SEN
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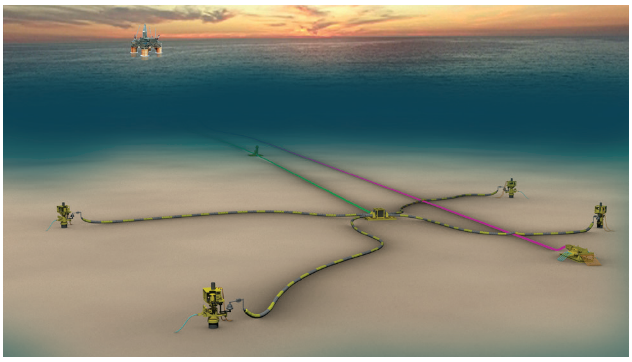
Shell Shows Way To Competitive Deepwater Production

When Shell first produced oil from its Kaikias project in the Gulf of Mexico in late May it was a great example of how efficiencies can be gained within the "lower for longer" price environment.

Kaikias, which has estimated peak production of 40,000 boe/d, is located in the prolific Mars-Ursa Basin about 210 km (130 miles) from the Louisiana coast. It is a tieback with four wells that utilize a single flowline going back to the Ursa platform. Production began about a year ahead of schedule, and Shell has reduced costs by about 30% on this deepwater project since taking final investment decision (FID) in early 2017, lowering the forward-looking, breakeven price to less than $30/bbl.



Shell was able to use just one compact plan instead of having to use a manifold and a pipeline end termination to reduce the subsea footprint in its Kaikias project. (Source: Shell Kaikias)

Amir Mansouri, Shell's Kaikias business opportunity manager, spoke with *SEN* about the processes and technologies that have facilitated the development.

***SEN:* What were the challenges that you faced both gaining FID and achieving the cost-effective and early start of production?**

Mansouri: When we started developing Kaikias, it was at the low point of the oil price environment, so one of the big challenges was that to mature a project we had to become twice as completive overnight. We had to very quickly adapt to a new reality, and we had to figure out how to crack the code to mature the project in a capital-efficient manner. In doing so, we had to ensure we had an alignment with the new ways of working both internally and externally.

***SEN:* What is different about this project?**

Mansouri: The overall scope on the subsea is a single flowline together with a compact manifold, flexible jumpers and an umbilical all tying back to an existing host with minimal topside alterations.

What is new here is first, we are reusing the exploration and appraisal wells as keeper wells that we will produce from. That was a real enabler for us. Another one is that we have significantly simplified the subsea layout, and the compact manifold is in its first application in the Gulf of Mexico. That enables us to use just one compact plan instead of having to use a manifold and a pipeline end termination that reduces the subsea footprint.

We also used flexible jumpers for the first time in the Gulf of Mexico on this type of project which, as their name implies, provided significant flexibility in the field layout that we could use in terms of the top-hole locations relative to the manifold.

WHAT'S INSIDE

SEN: **What about early engagement with the supply chain? How has that benefited the project?**

Mansouri: We involved our contractors much earlier than we traditionally do. We engaged with them during the feasibility stage where we shared with them the opportunity and asked how they might be able to achieve that efficiently with a shared target and shared vision for the project. That allowed us to make informed decisions about the project. It also enabled us to make sure that the contractors were aware sooner, so we could work together to ensure a safe and flawless execution.

SEN: **Are there any particular partners with whom you worked closely?**

Mansouri: TechnipFMC worked closely with us on the application of the compact plan, which is a new type of kit they have developed in recent times, and we worked closely with them on this first application and, of course, on the flexibles. They also ended up being the installation contractor and so were fully aware of the scope, which is a very good example of early contractor involvement and engagement.

What we recognized was that contractors and suppliers have unique capabilities that they have developed over the years in deep water, and we saw that we can benefit from involving them earlier. We have had collaborative relationships with several of our contractors including FMC, before they merged with Technip, so in a way, we have always worked closely with them. What is new here is that we have brought them in an integrated manner where we looked at the opportunity end-to-end, rather than just looking at one element of their scope, a lot sooner. It is that integrated approach looking at the value chain across the spectrum and involving contractors in that conversation early on that is an evolution of what we have been doing for many years.

SEN: **What prompted the decision to use appraisal wells for production?**

Mansouri: One of the reasons is that as you are exploring and appraising your well locations [and] they may be in a different location from where you want to produce from. That is simply part of the reason for drilling those wells. What we have been able to do here is identify well locations that satisfied both of those objectives. By optimizing that and integrating across the organization early in the project, we were able to identify locations for the exploration and appraisal well, and then later on we could use those as producing wells.

SEN: **An important part of the infrastructure is the compact manifold. What benefits does this deliver?**

Mansouri: The compact manifold, as the name implies, is smaller and lighter, and when used with a single flowline, as we have done here, enables it to be installed in one go. You are able to install your flowline and your manifold in a single campaign rather than having to use separate installation vessels to install that.

The other thing that it has enabled us to do is that now you don't need a pipeline end termination, because your pipeline end termination and your manifold have now been combined into one piece of kit—so better cost, better schedule and lower exposure.

SEN: **What prompted the decision of adopting a single flowline?**

Mansouri: We evaluated very carefully the fluids that we had to see if we were able to do a single flowline. We looked at the trade-offs, and we looked at having a single flowline versus a double flowline. The advantage of having a dual flowline was a bit more flexibility, but the competitiveness of a single flowline really made it more attractive.

SEN: **What lessons have you learned on Kaikias that can be used on other projects?**

Mansouri: We very much see Kaikias as a blueprint for projects going forward, and we have already started the process of making sure that the valuable lessons we are now seeing on Kaikias can be applied across our portfolio and that is happening.

Some of the lessons are really about a culture that enables integration across the value chain as well as with our contractors, clear and tangible kit, a process that ensures that translates into a scope, a simplified and fiscal purpose scope that is informed by what is available in the market and careful execution planning early on with key contractors.

Kaikias is a very good example of what we can achieve. I also believe that for us at Shell, Kaikias is a starting point. We have been operating in the Gulf of Mexico and deep water for over 40 years, so we have a long track record here and Kaikias marks a new chapter. But it is also a chapter we want to build on and further improve going forward.

There are further opportunities that we are going after; we are not standing still. We see opportunities around further integration across the value chain. We also see opportunities for further standardization and our ability to use equipment interchangeably to be able to move faster.

SEN: **What part can standardization play?**

Mansouri: We see good opportunities there. Going from discovery to first oil in four years in recent history for a deepwater subsea tieback is remarkable, and I think that we can do even better and we have started that journey. Standardization is potentially one element of that. We have carried out standardization in Shell before, and we have seen the benefits and we have benefitted on Kaikias as well. We have utilized standard subsea trees that enabled us to accelerate the project, and we see more opportunities to build on that.

***SEN:* What other technologies can help further reduce costs and compact the time lines?**

Mansouri: There are three things that come to mind there. I am excited by what I see in the way of analytical tools that enable us to make decisions faster and analyze trade-offs, particularly when it comes to the subsurface domain. At Shell, we have proprietary technology when it comes to seismic imaging. That was a key enabler for us at Kaikias, and I see us making a lot more progress in that space.

Another opportunity that I see is further automation in some of our drilling and automation activities. I'm encouraged by what I see in the market. The other one that we have already discussed is standardization. I believe that we have a very good foundation there, and I'm excited by what we can achieve as we further improve this.

—Mark Venables

DEVELOPMENT

Four Firms Join Race For Erawan, Bongkot Fields

Thailand's state-run PTT Exploration and Production (PTTEP), Chevron, Total and Mubadala Petroleum are vying to develop two offshore concessions, which comprise the oil- and gas-producing Erawan and Bongkot fields in Gulf of Thailand, after existing contracts expire.

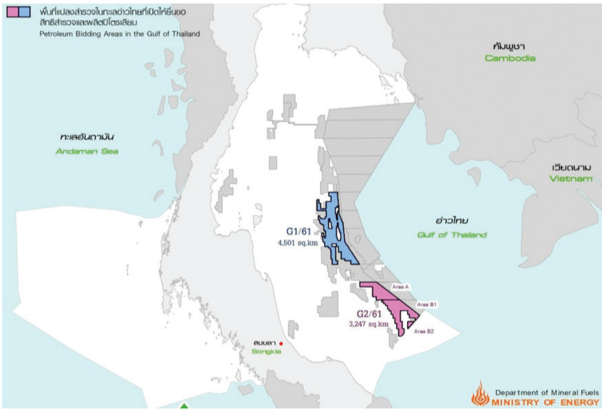
Thailand's Department of Mineral Fuels (DMF) shortlisted four companies—PTTEP, Chevron, Total and Mubadala Petroleum—for the G1/61 Block (Erawan Field) and three companies—PTTEP, Chevron and Mubadala Petroleum—for the G2/61 Block (Bongkot Field) after the prequalification round.

OMV Aktiengesellschaft participated in prequalification bidding for the two blocks launched in April but failed to cross that round.

"The winning bidders should be announced in December this year," DMF Director General Veerasak Pungrassamee said.

The production-sharing contracts (PSC) for the G1/61 and G2/62 blocks are scheduled to be signed by February 2019. The two concessions, however, will be allocated after the expiry of the existing development contracts for Erawan and Bongkot fields in April 2022 and March 2023, respectively.

The Erawan Field, operated by Chevron, produces 1,300 MMscf/d of gas, while the PTTEP-operated Bongkot Field pumps about 841 MMscf/d of gas and 276,000 bbl/d of condensate. These fields together produce about 70% of Thailand's domestic gas production and are expected to supply a large quantity of gas to the locals for many years.



Winning bidders for two offshore concessions in the Gulf of Thailand are expected to be announced in December. (Source: Thailand Ministry of Energy)

New PSC Regime

DMF's Pungrassamee said the two concessions would be offered under a new PSC regime with the focus on a greater proportion of returns to the government compared to the fiscal terms provided the previous bidding round. The new regime is based on the factors such as gas production, gas price and production share attributable to the government.

The selected contractors, according to the new PSC norms, must commit to a minimum production of 800 MMscf/d for G1/61 (Erawan) and 700 MMscf/d for G2/62 (Bongkot) for 10 years from the start of production. The output must be sold to the state or a state-owned company at a price comparable to the prevailing market price.

The offered gas price to the country's state-run oil and gas firm PTT will be the crucial criteria for the selection, making up 65% of the weightage in decision-making, while the benefits to the state, such as royalty, bonuses and recruitment of locals, account for the remaining.

The contractor also is required to share at least 50% of its profits with the Thailand government.

The exploration and development contract for the two blocks is offered for a period of 23 years, with an option to extend 10 years.

Significant Reserves

The two concessions are located in the hydrocarbon-rich Pattani and Malay basins in the Gulf of Thailand. Bid documents reveal that the proved oil and gas reserves in the G1/61 Block are estimated to be about 69 Bcm (2,435.59 Bcf) and 72.35 MMbbl, while that in G2/61 are 39 Bcm (1,375.52 Bcf) and 31.27 MMbbl (estimated at year-end 2016).

The Thai official said the producing Erawan and Bongkot fields are still left with significant quantity of oil and gas resources despite the extraction of hydrocarbons for the last three decades.

The northern part of Block G1/61 has oil and gas fields such as Plamuk, Platong, Surat, Yala and Kaphong. The central and southern parts of the block are mainly composed of gas fields like Pakarang, Satun, Erawan, Trat, Funan and Gomin.

The main source rock is the Oligocene lacustrine shale with high organic content in the Sequence 1 (oil prone). The Sequence 2, 3 and lowermost Sequence 4 also can be potential source rocks (gas-condensate prone).

The G2/61 Block covers f 3,247 sq km (1,253.6 sq miles) and is located south of the G1/61 concession. It is considered to be a major potential prospect in the Gulf of Thailand with the presence of hydrocarbon in Greater Bongkot North and Greater Bongkot South areas.

Gas in these two and neighboring fields in Gulf of Thailand is considered to be wet gas with a very high petrochemical content.

A DMF official estimated that the selected contractors could invest about $39 billion in development of Erawan, Bongkot and other leads in the two blocks.

—Ravi Prasad

DEVELOPMENT BRIEFS

Total Finishes Culzean Field Topsides Installation

All of the topsides facility items have been installed ahead of schedule for the Total-operated Culzean Field development in the U.K. North Sea, the company said July 10.

The topsides were installed by Heerema Marine Contractors, which used the *SSCV Thialf* heavy-lift vessel. In all, it took about 33 months, including design and fabrication, to reach the milestone, according to Total.

The HP/HT field, which is expected to start producing natural gas in summer 2019, comprises a wellhead platform, central processing facility, utilities and living quarters, flare stack, gas compression module, power generation module and bridge links. Joint venture partners in the project are BP and JX Nippon.

Hurricane Energy Stays On Track At Lancaster

Hurricane Energy is moving closer to first-half 2019 first oil for the early production system development of the Lancaster Field now that well completions operations are complete.

Field development plans for Lancaster include the tieback of two wells to the *Aoka Mizu* FPSO. (Source: Hurricane Energy)

The company said both production wells are ready to be tied into the subsea infrastructure.

"The installation of the mooring system is currently ongoing and will be followed by the SURF [subsea umbilicals, risers and flowlines] program," the company said in a news release July 6. "These elements remain on schedule to take place prior to arrival of the FPSO at the field, and first oil remains on target for 1H 2019."

The early production system is expected to be the U.K.'s first basement field development. The development will include two wells tied back to the *Aoka Mizu* FPSO. Production is initially expected to be about 17,000 bbl/d, Hurricane said.

Abu Dhabi's NPCC Wins Contract For Offshore Bu Haseer Field

Abu Dhabi National Oil Co. (ADNOC) subsidiary Al Yasat has awarded an engineering, procurement and construction contract for the Bu Haseer Field to Abu Dhabi's National Petroleum Construction Co.

The contract covers engineering, procurement, construction and commissioning activities for the field's offshore facilities. The operator aims to double the field's production capacity to 16,000 bbl/d in 2020.

The field is located offshore Abu Dhabi in the Al Yasat concession area, which is being developed by the joint venture between ADNOC and CNPC.

Eni Cranks Up Gas Production At OCTP Sankofa Field Offshore Ghana

Gas production has started from two of four deepwater subsea wells at the Sankofa Field, which is part of Ghana's Offshore Cape Three Points (OCTP) Integrated Oil and Gas Project, according to Eni.

The wells are connected to the *John Agyekum Kufuor* FPSO.

"After the final steps of commissioning of the offshore facilities, production will gradually flow via a dedicated 60-km [37-mile] pipeline to the onshore receiving facility in Sanzule, where gas will then be compressed and distributed to Ghana's national grid," Eni said in a news release.

The field is expected to provide 180 MMscf/d of gas for at least 15 years.

With 44.44% interest, Eni serves as operator of the OCTP project. Partners are Vitol (35.56%) and GNPC (20%).

SBM Offshore Lands Contracts For ExxonMobil's Second Liza FPSO

ExxonMobil subsidiary Esso Exploration and Production Guyana Ltd. (EEPGL) has selected SBM Offshore to carry out FEED for a second FPSO for the Liza development in the Stabroek Block offshore Guyana.

SBM said the FPSO's design is based on its Fast4Ward program, which incorporates the company's newbuild, multipurpose hull combined with several standardized topsides modules.

The FPSO, which will be spread moored in water depth of about 1,600 m (5,249 ft), will be capable of producing 220,000 bbl/d of oil and storing about 2 MMbbl of oil, according to SBM. The vessel also will have associated gas treatment capacity of 11 MMcm/d (400 MMcf/d) and water injection capacity of 250,000 bbl/d.

"Following FEED and subject to requisite government approvals, project sanction and an authorization to proceed with the next phase, SBM Offshore will construct, install and then lease and operate the FPSO for a period of up to 2 years, after which the FPSO ownership and operation will transfer to EEPGL," SBM said in the release.

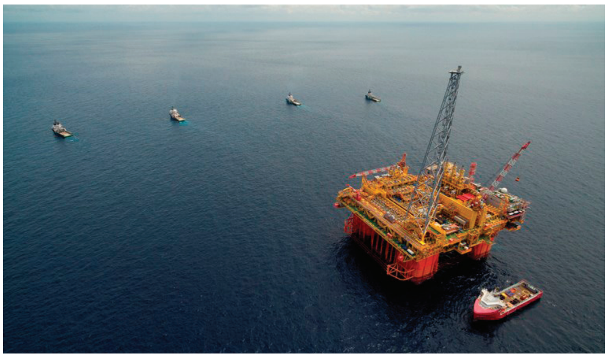
The company also reported that FPSO *Liza Destiny* for Liza 1 is progressing with conversion underway in Singapore. In addition, "discussions with the client are underway regarding a potential accelerated transfer of ownership using the purchase option in the 10-year lease contract," SBM said. "The outcomes of these discussions are expected to lead to a transfer of the FPSO ownership and operation after a period of up to 2 years."

EEPGL is the operator of the Stabroek Block. Partners are Hess Guyana Exploration Ltd. and CNOOC Nexen Petroleum Guyana Ltd.

Australia Regulator Finds Safety Problems On Inpex Offshore Gas Platform

An Australian regulator said on July 9 it had found some safety problems on the offshore gas platform for Japanese firm Inpex Corp.'s Ichthys LNG project off northern Australia and was considering enforcement action.

The National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA) found "deficiencies in the suitability of electrical equipment in hazardous areas" during a four-day inspection of the Ichthys Explorer platform in late June, a spokeswoman said in emailed comments. NOPSEMA said its inspection has yet to be formally concluded so it could not provide any further details.



The Ichthys LNG Project's central processing facility, Ichthys Explorer, arrives in Australian waters following a 5,600-km tow from South Korea in May 2017. (Source: Inpex Corp.)

Inpex had hoped to start producing gas from the long delayed $40 billion project in June, but the company's new CEO, Takayuki Ueda, told Reuters last week the company still had to address "various minor issues."

An Inpex spokeswoman declined to comment on the specific technical issues. During final safety checks required before startup, some minor areas for improvement were identified, but they posed "no major challenges," she said. "We are firmly committed to the safety of our workers above all else and will only commence production from the wellhead when we are satisfied that final safety verifications are completed.

Ichthys will send gas from the offshore central processing facility through an 890-km (550-mile) pipeline to the mainland near the city of Darwin, where it will be chilled into LNG for export.

Eni Starts Bahr Essalam Phase 2 Production Offshore Libya

National Oil Corp. and Eni have started production from the first well of the offshore Bahr Essalam Phase 2 project, the joint venture said July 5.

This comes just three years after the final investment decision. Two further wells will begin production within a week. An additional seven wells will come onstream by October.

Phase 2 of the project completes the development of the largest offshore producing gas field in Libya, increasing production potential by 400 MMscf/d. Phase 2 will be completed between September and October, bringing total field production to 1,100 MMscf/d. Bahr Essalam, located about 120 km (74 miles) northwest of Tripoli, contains more than 260 Bcm (68.6 Tcf) of gas. This is delivered through the Sabratha platform to the Mellitah onshore treatment plant before principally being used to supply the national network.

Equinor Lands Approval For Snorre Field Expansion

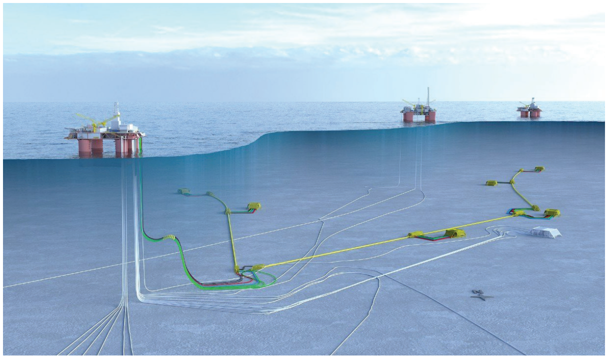
The Ministry of Petroleum and Energy has approved Equinor's plan for development and operation for the Snorre expansion project, the company said July 5.

Investments of just above $2.3 billion will increase recovery from the Snorre Field by almost 200 MMbbl and extend the field life beyond 2040.

The Snorre expansion project is the largest project for improved recovery on the Norwegian Continental Shelf. The project involves a comprehensive subsea development, upgrading of the Snorre A installation, increased gas injection and gas import for injection.

The Snorre Field was originally estimated to produce until 2011-2014. Now the field life has been extended beyond 2040, and the recovery rate increases from 46% to 51%.

Scheduled to start production in 2021, the Snorre expansion project will be operated and maintained by the existing Snorre organization in Stavanger. Supplies will still be handled by Fjordbase in Florø.



A field illustration of the Snorre Expansion Project includes plans for six new subsea templates for production and alternating water/gas injection. (Source: Equinor)

Subject to final regulatory approval, the partners have awarded contracts for the subsea production system to TechnipFMC, fabrication and installation of the pipeline bundle system to Subsea 7, Snorre A modifications to Aibel, drilling and well operations to Transocean, and marine installations to Deep Ocean.

Equinor Submits $955 Million Phase 3 Development Plan For Troll Field

On July 3 Equinor submitted a $954.46 million plan to develop gas reserves in the western part of its Troll Field, the largest gas field off Norway.

Reserves of 2.2 Bboe will be produced by using subsea installations tied in to the Troll A platform, which is about 25 km (15.53 miles) northwest of the reserves, in Phase 3 of development, Equinor said in a statement.

"It has a breakeven [price] of less than $10 per barrel," said Margareth Oevrum, head of Equinor's technology, projects and drilling.

Equinor holds a 30.58% stake in the Troll Field with partners Petoro (56%), Shell (8.1%), Total (3.69%) and ConocoPhillips (1.62%).

Equinor said it planned to sign contracts July 3 with marine installations and subsea facilities totaling $92 million with Allseas, Nexans and Deep Ocean.

TechnipFMC Lands Contract For Total's Zinia Phase 2 Field Development

TechnipFMC said July 2 it has been awarded a contract by Total E&P Angola for the Zinia Phase 2 field development, located offshore Angola at a water depth between 800 m and 1,000 m (2,624 ft and 3,280 ft).

The contract covers the engineering, procurement and construction of subsea equipment including nine subsea tree units as well as wellheads, subsea control systems, connection systems and associated equipment. This contract also covers support services, performed by TechnipFMC in Angola, for the assembly, test, mobilization and installation.

—Staff Reports

EXPLORATION

Norway Exploration Scene Building Up Steam

Since the beginning of the year, exploration activity offshore Norway has been increasing at a gradual, if not spectacular, rate. Confidence is certainly growing now that the sector is in a healthier state than last year when talk of the green shoots of recovery started to gather momentum.

The three main players are Equinor (formerly Statoil), Spirit Energy and Aker BP, with two North Sea stalwarts, Shell and Total, also involved in drilling work. Lundin Petroleum also is an active driller in the area, as is Wellesley Petroleum.

NCS: 40 Johan Castbergs Left

The Norwegian Petroleum Directorate (NPD) recently published the "2018 Resource Report for Exploration"—with the conclusions backing up growing confidence in the Norwegian exploration scene and the future outlook.

The report said that production of oil and gas will increase going forward, but that new and larger discoveries have to be made to maintain the same level after the mid-2020s.

There is a lot of remaining oil and gas on the Norwegian Continental Shelf (NCS), which still "provides significant opportunities in both mature and less explored areas."

Increased knowledge, more and improved data, new work methods and new technology will create new exploration possibilities and can yield more profitable discoveries. However, to maintain the production of oil and gas over time, companies must explore—and discover—more, the report stated.

"This report includes an updated overview of undiscovered petroleum resources on the NCS. It shows that after more than 50 years of activity, about 55% of anticipated oil and gas resources have yet to be produced. Of these, just under half have not even been discovered," the NPD's exploration director Torgeir Stordal said.

The estimate for undiscovered resources is 4,000 MMcm of oil equivalents (MMcmoe), which equates to about 40 Johan Castberg fields. The NPD expects about two-thirds of the undiscovered resources to be located in the Barents Sea; the rest is distributed between the North Sea and Norwegian Sea.

"The figures tell us that opportunities on the NCS are great and could provide the basis for oil and gas production for decades to come," Stordal said, adding that it is important that companies continue to actively explore in both familiar and more frontier areas, and that a diverse range of players contribute to this.

Spirit Wraps Fogelberg Appraisals

Spirit Energy has completed the drilling of appraisal wells 6506/9-4 S and 6506/9-4 A on gas and condensate discovery 6506/9-2 S (Fogelberg) in production license 433 (PL 433) offshore Norway.

The wells were drilled about 15 km (9 miles) north of the Åsgard Field in the Norwegian Sea and 250 km (155 miles) west of Brønnøysund. The wells were drilled by *Island Innovator* unit.

The Fogelberg discovery was proven in multiple levels in Middle Jurassic reservoir rocks in the Ile and Garn formations in 2010. Before the two appraisal wells were drilled, the operator's resource estimate for the discovery was between 4 MMcmoe and 15 MMcmoe (141.2 MMcfoe and 529.5 MMcfoe).

"The objective of well 6506/9-4 S was to reduce the uncertainty associated with the reservoir quality and resource estimate for the Garn and Ile formations in the 6506/9-2 S discovery," the NPD said.

The preliminary estimate of the size of the discovery following the appraisal wells is between 7 MMcm and 14 MMcm (247.1 MMcf to 494.2 MMcf) of recoverable oil equivalents. The licensees are planning to develop the discovery as a subsea development tied in to the Åsgard B facility.

Following these wells the NPD granted Spirit Energy a drilling permit for exploration well 7322/7-1 in PL 852 offshore Norway.

Well 7322/7-1 also will be drilled by the *Island Innovator* unit about 70 km (43 miles) west of 7324/8-1 (Wisting) and 110 km (68 miles) northeast of the Johan Castberg development.

Equinor Eyes Eagle

The NPD has given Equinor consent to drill exploration drilling 7324/3-1 in the Barents Sea. The well will target the Intrepid Eagle prospect, which is located about 172 km (107 miles) southeast of Bjørnøya in PL615. The water depth at the site is 452 m (1,483 ft).

Drilling is due to start in mid-August and is estimated to last for 28 days, depending on whether a discovery is made, the NPD said. The well will be drilled by the *West Hercules* semisubmersible rig.

Prior to this, Equinor completed exploration well 34/8-19 S in PL 120 as a dry hole. The well was drilled on the northern side of the Visund Field in the northern sector of the Norwegian North Sea.

Well 34/8-19 S was drilled by the *Deep Sea Atlantic* rig, which will now move to drill development well 34/8-D-4 AH on the Visund Nord Field in the North Sea, where Equinor is the operator.

Aker BP Gets Permit

The NPD has given Aker BP a drilling permit for wells 25/10-16 S, 25/10-16 A and 25/10-16 B offshore Norway.

The wells will be drilled by the *Maersk Intrepid* rig once it completes drilling production wells on the Martin Linge Field in the northern part of the North Sea.

The drilling program for wells 25/10-16 S and 25/10-16 A relates to the drilling of two appraisal wells and the drilling of one wildcat well 25/10-16 B in PL028 B.

Aker BP is operator of PL 028 with a 35% stake, with Equinor (50%) and Spirit Energy (15%).

"The wells will be drilled about 10 km [6 miles] north of the Ivar Aasen Field in the central part of the Norwegian North Sea," the NPD said.

Scarabeo 8 to spud Jasper prospect

Norway's Petroleum Safety Authority (PSA) has given Total consent to use the *Scarabeo 8* rig to drill an exploration well in the Norwegian Sea.

The PSA said well 6406/6-5 S has a planned spud date of July 1. Operations are expected to take 90 days to complete. The well, located in Total-operated PL255B, will target the Jasper prospect at a water depth of about 267 m (876ft).

Shell's Norway Dry Hole

Shell has completed exploration well 34/5-2 S in PL 373S offshore Norway as a dry hole.

The well was drilled about 10 km southwest of the Knarr Field in the northern part of the Norwegian North Sea and 125 km (78 miles) west of Florø.

Well 34/5-2 S was drilled by *Scarabeo 8,* which will be drilling wildcat well 6304/3-1 in the Norwegian Sea in PL832, which is operated by Shell.

—Steve Hamlen

EXPLORATION BRIEFS

Galp To Start Drilling Exploration Well Offshore Portugal

Portuguese oil company Galp Energia is set to start drilling the country's first deepwater offshore exploration well but with only modest hopes of success, the company's E&P director said July 2.

The project is being developed by a consortium of Galp and Eni off the Alentejo region's Vicentine coast, which is known for its beaches and large natural park. The move has led to protests by environmental activists and local municipalities.

Thore Kristiansen told Reuters on the fringes of a petroleum engineering event in Lisbon the seismic data shots made the project look "interesting enough so that we at least have to try," even if it turns out dry. He said the partners were "calibrating" the project to meet various conditions set by the Portuguese Environmental Agency in May but did not expect any delays. The agency has deliberated that drilling has to be carried out at some point between Sept. 15 and Jan. 15.

"But this is frontier drilling. Nobody has done it before and there is a high likelihood that we will not find anything," he said, adding that the geological formation could be similar to the oil-containing structures along the eastern coast of Canada. "We have applied the same ... models for what we are doing in Portugal. But the reality is that we don't know."

Israel's Navitas Raises Estimate At Gulf Of Mexico Oil Field

Israel's Navitas Petroleum said on July 1 its Yucatan oil field in the Gulf of Mexico is estimated to have more than triple the reserves than previously thought, according to a new contingent resources report.

The Yucatan Field, which is located in deep waters about 282 km (175 miles) south of Louisiana, contains an estimated 49 MMbbl of oil, up from a previous estimation of 15 MMbbl, the company said.

The report was prepared by Texas-based consultants Netherland, Sewell and Associates (NSAI).

Navitas has a 23.1% stake in the field, while LLOG Exploration holds 46.9% and Venari Offshore has a 30% share.

Yucatan is near another field Navitas is looking to develop, Shenandoah, which is estimated to contain 155 MMbbl of oil.

"NSAI's contingent resources report for Yucatan points to a significant increase in the scope of resources and supports the future joint development of the two fields," Navitas Chairman Gideon Tadmor said.

Cooper Energy Completes Sole-3 Flowback

Sole-3, the first of two production wells for the Sole gas project offshore Australia, has been shut in for future connection after cleanup and flowback operations were performed successfully, Cooper Energy said July 6.

"We now have a well in place, ready to go, with production capability exceeding project requirements. Reservoir quality, production performance and the gas composition are all in line with predrill expectations" Cooper Energy Managing Director David Maxwell said in a news release. "We now move on to resuming Sole-4 and completing the project's drilling requirement."

The Diamond Offshore Ocean Monarch conducts flowback operations at Sole-3. (Source: Cooper Energy)

The company said the cleanup and flowback test was conducted over a 26-hour period on the near-horizontal 97-m (318-ft) completed section of the Top Latrobe Group sandstone reservoir. Well performance and reservoir deliverability are consistent with predrill expectations based on analysis on test data.

"The flow rate was constrained by surface well test equipment to a maximum of about 48 MMscf/d through a 104/64-in. choke. During a 9-hour flow period, through a 88/64-in. choke, the flow rate averaged about 38 MMscf/d," Cooper said in the release. "Post-test analysis of the Diamond Offshore Ocean Monarch conducting flowback operations at Sole-3 on July 5 measured data has confirmed Sole-3 capability to produce above the maximum plant throughput rate of 68 TJ/day under production conditions."

The well is being suspended before pipeline connection. Cooper anticipates starting pipelay operation, and connecting the Sole gas field with the Orbost Gas Processing Plant to begin in October.

—Staff & Reuters Reports

TECHNOLOGY

Expert: Well Intervention Technology Can Pave Way To Improved Productivity

In this Q&A, Malcolm Banks, well construction solution center manager for the Oil & Gas Technology Centre (OGTC) in Aberdeen, Scotland, discusses work being done on well intervention technology that he said could pave the way for wider adoption. He said the technology has the potential to change the way wells are managed. The benefits include improved productivity that could over time save the industry millions of dollars.

OGTC is looking at new ways of developing and delivering the level of intervention that will reduce cost with new methods of working. (Source: Shutterstock.com)

Hart Energy: How does the sector need to change its well management strategy?

Banks: When you look across the industry, something like 400 wells had to shut in at some point last year. That's usually for two reasons: well integrity or well management. To overcome these problems requires some form of intervention. The challenge there is cost and [for offshore wells] the ability to get the people onto a platform when the bed space is already full.

Hart Energy: What is the current state of available technology?

Banks: It's about technology capability needed to address some of the challenges that we face with well management and well integrity issues. We're trying to focus on the technology aspect, and the industry will have to address some of the other issues.

Well intervention now is dominated by the need to bring in a wireline or a slickline crew and go digging into the well. Some of those technology tools and techniques require a crew of 10 to 12 men on a platform, which means that they're very expensive. They haven't changed the way they are being undertaken for about 30 or 40 years. What we're trying to do is look at new ways of developing and delivering the level of intervention that will reduce cost with new methods of working.

Hart Energy: Where are you targeting your efforts?

Banks: We're looking now at two things. One is trying to get tools that are controllable from the surface. One of our projects, Tendeka's PulseEight system, allows the control of a downhole valve by descending pressure pulses from the surface, so you don't need to go in with wireline or slickline for the intervention [and] it can be carried out from the surface.

In another project, we're supporting Raptor Oil to transform the transmission of downhole drilling data to the surface. The company's acoustic telemetry technology could increase the speed and capacity of data communication helping to drive efficiency, reduce costs and enable better decision-making.

A third one is supporting WellSense to develop and deploy a distributed acoustic and temperature log using the company's FibreLine Intervention. This system provides a low-cost option to deploy fiber-optic cable into a wellbore to capture distributed temperature and acoustic readings as well as single point pressure and temperature from the body of the tool.

Hart Energy: So where do we want to get to as an industry in the future?

Banks: When you look at where we want to go to in the future from our perspective as a technology organization, our focus is very much on how do we get a lot more functionality in these remote operational tools? Or how do we construct wells in the first place that are more intelligent and are able to respond themselves to data and pressure changes that come forward as their life continues?

The ideal utopia would be if you install programmable devices down the well when you build a well, and as the well is in production you've got a lot of real-time data management at the surface. You can analyze that, and then when you see something occurring that you need to respond to, you can do that remotely from the surface just by triggering one of these pre-installed tools. That sort of closed loops-controlled type system that would be the new well management regime.

Hart Energy: How do you identify the technology gaps or requirements?

Banks: What we want to do is make sure that what we put forward technology that is pulled from industry. We work very closely with organizations that are partnering with us as well as the industry in a broader sense. What we tend to do is create or facilitate workshops where we bring that industry grouping together. We get them to define and prioritize the key challenges in areas and then we go out and put an open call to the innovation community to try to bring in ideas that we're going to evaluate and look to turn into projects.

Hart Energy: What is the desired outcome of your work?

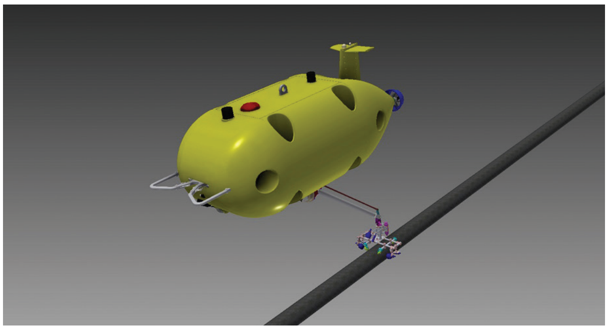
Banks: We want to try to ensure that wells are kept online and we're able to produce 100% of the time. We want no failures due to some well integrity issues, the ability to manage wells such that any pressure and fluid challenges can be addressed, and the wells to be kept in production. To do that, we need high-quality data to make predictive decisions to enable us to manage wells, and then, we need either pre-installed or remote intervention mechanisms that would allow us to address any particular issues.

—Mark Venables

TECHNOLOGY BRIEFS

Kawasaki Reaches Agreement With TUC To Test AUV For Subsea Pipeline Inspection

Kawasaki Heavy Industries Ltd. reached a basic agreement with The Underwater Centre (TUC), a marine testing and training facility in Fort William, Scotland, on conducting a verification test of a prototype AUV equipped with a robot arm for subsea pipeline inspection. The test, scheduled for October, will be the first such test in the world.



Kawasaki is developing an AUV capable of underwater charging and transferring of inspection data to the mother ship. (Source: Kawasaki)

With a focus on the growing demand for pipeline maintenance in offshore oil and gas fields, Kawasaki has been developing component technologies for AUVs, based on sophisticated submarine technologies fostered in-house over many years, according to the company. Aiming at commercialization in 2020, Kawasaki is developing an AUV capable of underwater charging and transferring of inspection data to the mother ship—features that allow longer deployment time—while autonomously locating and tracking pipelines at close range, including those buried under seabed sediment.

For the upcoming test, leveraging on synergies of its technologies, Kawasaki plans to use a prototype AUV equipped with a robot arm with an attached inspection tool unit (under development) to achieve autonomous locating and tracking of subsea pipelines. The test will focus on verifying the robot arm's capability to absorb the movement of the AUV due to tidal currents and on verifying that the inspection tool unit can continuously track a pipeline under those conditions.

TUC will be collaborating with Kawasaki on future development of underwater vehicle technology in accordance with the agreement, a press release said.

Software Systems Developed For FPSO Inspections

Marine Technical Limits has developed Pyxis, a software system that helps track risk-based integrity management strategies for the hull structure of FPSOs and FSUs.

According to a press release, the system was borne out of the need to assess and catalog vast amounts of inspection data.

The Pyxis dashboard, which is accessible from any internet-connected device, provides onshore management teams (integrity managers, inspectors, classification surveyors and asset leads) with on-the-spot, easy-to-interpret visual overviews of the health and status of vessels' hull integrity.

Pyxis helps assess structural integrity issues on FPSOs and FSUs. (Source: Marine Technical Limits)

The information is driven by gathered inspection data and assessments carried out by Marine's team of architects. This is further supported by graphical representations of anomaly trends, breakdown of anomaly types and overdue and upcoming inspection forecasting.

Pyxis features the ability to digitally define inspection work plans to allow tablet based inspection data recording, according to the company. As an inspection takes place, the data is uploaded to the dashboard immediately, allowing access to instant reports.

Nexans To Provide Umbilicals For Troll Field Project

Nexans said July 3 it will provide 27 km (16 miles) of complex umbilicals with power, fiber-optic and hydraulic elements for the next development phase of the Troll Field on the Norwegian Continental Shelf.

The initial development was carried out over two phases, and now Equinor is starting the Phase 3 development to recover the large amount of gas resources in the western part of the field. Nexans will supply Equinor with the complex umbilicals required to power and control the subsea systems.

Phase 3 of the Troll Field project is intended to recover the large amount of gas resources in the western part of the field. (Source: Nexans)

Phase 3 of the Troll project covers the development of the Troll West structure, which lies in water depths of approximately 330 m (1,082 ft) and is located 25 km (15 miles) northwest of the Troll A platform.

The subsea production systems will comprise two subsea templates or manifolds as well as nine trees. Each manifold is expected to have four well slots. Eight production wells will be drilled and tied-back to the Troll A platform to recover the gas reserves.

First gas is expected from the project in the second quarter of 2021.

For the Troll Phase 3 development, Nexans Norway will design, manufacture and supply static umbilicals that include high-voltage power elements, high-pressure hydraulic lines, low-pressure hydraulic lines, a methanol and glycol service line for chemical injection, a spare line and fiber-optic communications—all within a single cross section.

A 20-km (12-mile) umbilical will link the Troll A platform to Template W1, while a 7-km (4-mile) umbilical will then link Template W1 to Template W2. The contract also includes the supply of connections, terminations and other umbilical accessories.

Nexans is scheduled to deliver the Troll Phase 3 umbilicals in the first quarter of 2020.

—Staff & Reuters

VESSEL BRIEFS

Subsea 7 Employees Name Newest Reel-Lay Vessel

London-based Subsea 7 SA's newest reel-lay vessel received its name, *Seven Vega*, during its July 5 keel-laying ceremony at Royal IHC's shipyard in Krimpen aan den Ijssel, The Netherlands.

"When delivered, *Seven Vega* will be one of the most capable and cost-effective reel-lay vessels in the market and a global enabler for Subsea 7," said Stuart Fitzgerald, Subsea 7's executive vice president for strategy and commercial. "It has been designed to deliver economical technologies that address the growing market trend toward longer tieback developments."

Fitzgerald said the vessel's pipelay system focuses on crew safety, operational efficiency and flexibility. It will able to install complex rigid flowlines including pipe-in-pipe systems and electrically heat traced flowlines in water depths up to 3,000 m (9,842.5 ft).

The vessel's name was selected from an employee competition that included more than 1,700 entries.

"We chose *Seven Vega* because Vega is one of the brightest stars in the northern sky and will become the North Star in the future," Fitzgerald said. "We look forward to welcoming the winner of the competition to the naming ceremony and to *Seven Vega* joining the fleet in the first half of 2020."

STR Joins With Forssea Robotics In Strategic Partnership

The partnership between Subsea Technology & Rentals Ltd. (STR) and Forssea Robotics, announced June 27, will connect the former's global customer base with the latter's advanced ROV technology.

U.K.-based STR specializes in the design, production and rental of advanced subsea technology. Paris-based Forssea, launched in 2016, focuses on the design and development of autonomous subsea robotics and underwater vision systems.

Negotiations for the formation of the partnership took place over the last year.

JV-Built *Skandi Recife* Begins Contract With Petrobras

Laden with pipelay and marine technology, the Brazilian-flagged *Skandi Recife* began its eight-year charter contract with Petróleo Brasileiro S.A. (Petrobras) in mid-June.

The flexible lay and construction vessel, owned by the 50:50 joint venture (JV) between TechnipFMC and DOF Subsea, will work in the Campos, Santos and Espírito Santo basins offshore Brazil. TechnipFMC will manage flexible pipelay and DOF will be responsible for marine operations under the JV agreement.

Skandi Recife boasts a 340-ton vertical lay system tower with a 2,500-to underdeck carousel and two ROVs. The ship can lay flexible pipelines in depths of up to 2,500 m (8,202 ft).

The vessel was built in Vard Promar's Brazilian yard. Its sister ship, *Skandi Olinda*, is under construction at the same shipyard.

Ulstein Verft Lands Deal To Build DP3 Cable-laying Vessel For Nexans

The winner in an intensely competitive bidding process to build Nexans Subsea Operations' next DP3 cable-laying vessel was announced on July 4: Ulstein Verft.

"We are very pleased that Nexans, a solid and important player, chooses Ulstein to construct their new flagship," said Ulstein Group CEO Gunvor Ulstein. "We have a strong organization with long experience in delivering advanced vessels. The contract was won in tough, international competition. We look forward to a constructive and fruitful cooperation with Nexans in the years to come."

The vessel has been designated ST-297 CLV and was designed by Ålesund, Norway-based Skipsteknisk for Nexans. The 17,000-deadweight-ton ship is specifically designed to operate in severe weather, with advanced maneuverability and station-keeping capabilities.

Ulstein Verft will build the 149.9-m-long (491.7-ft-long) vessel and prepare it for the addition of topside equipment. It will be outfitted for power cable laying, including bundle laying, cable jointing and repair and cable system protection and trenching.

"We are experienced in constructing large and complex vessels and we look forward to commencing the work on the cable laying vessel for Nexans," said Kristian Sætre, managing director at Ulstein Verft.

—Staff Reports

Skandi Recife can lay flexible pipelines in depths of up to 2,500 m. (Source: TechnipFMC)

BUSINESS

New E&P Player Vår Energi Emerges

On the back of a general feeling of an ongoing recovery in the oil and gas industry, Italy's Eni and private-equity investor HitecVision have agreed to merge Point Resources into Eni Norge to create "a new E&P Norwegian player" called Vår Energi.

The new company will be "built on the existing organizations and leveraging on complementary strengths," Eni said.

Vår Energi's assets "will have a wide geographical coverage, from the Barents Sea to the North Sea, producing around 180,000 boe/d this year from a portfolio of 17 producing oil and gas fields," Eni added, noting that the operator will have reserves and resources of more than 1.25 Bboe.

Production is forecast to reach 250,000 boe/d by 2023 after developing more than 500 MMboe in 10 existing assets, with a breakeven price of less than $30/bbl.

In total, Vår Energi plans to invest more than $8.1 billion over the next five years "to bring these projects onstream, revitalize older fields and explore for new resources," Eni said.

New Exploration For Point

While the merger is not scheduled to take place until fourth-quarter 2018, Point Resources gave *SEN* details of its heavy schedule of E&P work planned in the coming months. This work will surely be merged into Vår Energi's plans when the company goes live later this year.

"Point Resources is certainly committed to invest in increased oil recovery initiatives. We are currently planning to carry out a new six-well infill drilling campaign at the Ringhorne Field, planned to start in the first quarter of 2019. A major future drilling program at Balder is also being matured, supported by a new seismic survey acquired this summer," a Point spokeswoman told *SEN*.

The Balder and Ringhorne fields area is also the site of a new exploration program in 2019 that has been approved. "These activities, along with facility life extension programs, will significantly increase oil recovery at our operated assets," she added.

"Furthermore, we are committed to perform exploration drilling as partner in the PL 740, more specifically the Brasse prospect, expected to take place [fourth-quarter] 2018," she said. "Exploration activities in 2018 will focus on maturing prospects in existing licenses and identifying new drilling prospects in licenses awarded in the Awards for Pre-defined Areas 2018. In addition, the Hornet prospect in PL 777 in the North Sea is being prepared for exploration drilling, planned to take place in the second half of 2018."

Vår Energi will be jointly owned by Eni (69.6%) and HitecVision (30.4%).

The new company will have about 800 employees, including offshore and onshore staff. HSE performance, projects delivery and production efficiency will be priority areas for the management.

Kristin F. Kragseth, currently vice president of production for Point Resources, will become CEO of the combined entity, while Philip D. Hemmens will be the chairman of the board. Hemmens and Mauritzen will remain in their respective positions until completion of the merger.

The combination is subject to customary closing conditions and regulatory approvals and is expected to be completed by year-end 2018, Eni said in a statement.

Portfolio Growth

"The extended presence in the Norwegian waters will allow the company also to expand further its portfolio through both future exploration bid rounds and M&A [merger and acquisition] transactions," the Italian operator added.

Eni CEO Claudio Descalzi said, "This is a fundamental step ahead in our strategy to reinforce Eni's presence in OECD [Organization for Economic Co-operation and Development] countries with further upstream potential, such as Norway. The high quality of the human capital, as well as of the assets in the portfolio, together with the expansion opportunities still available in Norway, will create a significant upside value to the shareholders of the merged company.

"Eni will bring into Vår Energi its globally recognized capacity to innovate and its best technology, which has enabled us to achieve remarkable results in recent years, through great discoveries and the startup of these discoveries in a record time."

Ole Ertvaag, CEO of HitecVision, added, "We are proud to bring together two E&P organizations that each have a history in Norway going back to the very beginning of our oil and gas industry, with license 001 from 1967 and participation from the start in Ekofisk, the first oil field in Norway.

"After more than 50 years Norway still has very significant oil and gas resources, and the combination of Eni and Point builds on decades of experience to create an all-new company for the decades ahead."

Morten Mauritzen, CEO of Point Resources, said, "Point Resources has come a long way in a short time since acquiring ExxonMobil's operated business in Norway last year. Vår Energi will be one of the largest independent E&P companies in Norway, with strong growth ambitions for the future.

"A large portfolio of operated and nonoperated fields, increased focus on exploration and many development projects means that it will go forward as one of the most exciting companies in the industry," Mauritzen added.

Philip D. Hemmens, managing director of Eni Norge, added, "The new company shall have the ambition, capacity and competency to deliver on its aggressive growth plans to be a safe and sustainable independent Norwegian E&P company for many years to come."

—Steve Hamlen

BUSINESS BRIEFS

Airborne Oil & Gas Names Oliver Kassam CEO

Oliver Kassan was named CEO of Airborne Oil & Gas (AOG). He was most recently at SBM Offshore N.V. where he served as president and managing director in charge of the company's activities in Brazil.

"We are very happy to welcome Oliver Kassam to Airborne Oil & Gas," Tim van Delden, chairman of the supervisory board, said in a statement. "Oliver shares our vision that AOG's Thermoplastic Composite Pipe (TCP) will become a significant component of the subsea pipeline infrastructure, in line with the industry's continued drive for reduction of total installed cost and life-cycle cost. With Oliver's global network and solid commitment to safety and quality, the supervisory board is confident that he can work with the AOG management team to lead the company to the next phase of growth and further success."

Kassam has more than 20 years of experience in the global offshore services industry holding various senior executive roles. He began his career in the oil and gas industry with KBR in 1996. He has since worked globally with extensive experience in the North Sea, Brazil, Gulf of Mexico, Middle East, West Africa and Asia.

He spent eight years with Subsea7 before joining SBM Offshore N.V in 2012 as part of a new management team to restructure the business. He began his new position on July 1 and is based in IJmuiden, The Netherlands.

Nexans Appoints Christopher Guérin As CEO

The board of directors of Nexans appointed Christopher Guérin as CEO on July 3, during a meeting chaired by Georges Chodron de Courcel.

Guérin has been with Nexans since 1997 and most recently since 2014 served as senior executive vice president, Europe and Telecom/Datacom, and member of the group management board.

In a statement, Nexans said during his years with the company, Guérin has demonstrated strong and decisive leadership while successfully leading economic and social transformations in highly competitive international environments. In 2017, Guérin was instrumental in building the present "Paced For Growth" strategic plan.

Arnaud Poupart-Lafarge will serve as adviser to the new CEO until Sept. 30.

"Christopher Guérin is a solid and inspiring executive who has demonstrated many successes within the group," de Courcel, said. "The board of directors unanimously supports him in his new mission to which he brings not only an in-depth knowledge of the cable industry but also a clear strategic view as to avenues of future growth."

—Staff & Reuters

UPCOMING

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