November/December 2018

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Continental Focus, International Reach

15th ANNIVERSARY

Wireless Well Development

Supermajors Cost Efficiency

Pipeline Progress

African Focus

Equatorial Guinea * Gabon * Republic of Congo

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Source: Tendeka

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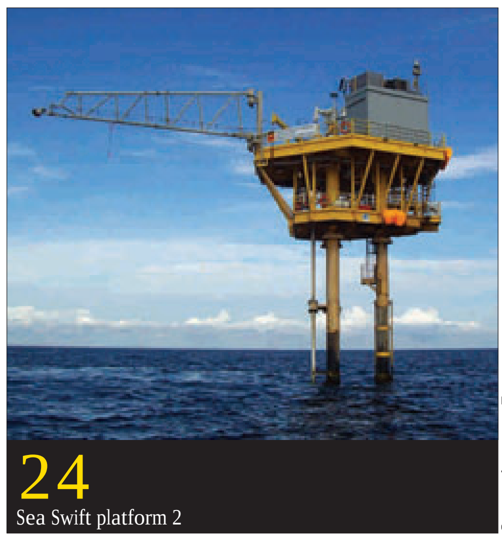
Source: Aquaterra Energy

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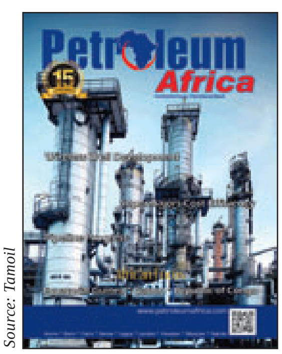
Sea Swift platform 2

ON THE COVER



Source: Tamoil

Libya looks to relocate its Swiss refinery to the south of the country, bringing new jobs to the region in the process.


Raymond N. Plank

The industry will be missing one of its veterans. Raymond N. Plank, a US WWII bomber pilot who watched from the air as a mushroom cloud formed over Nagasaki, then returned to the United States to build Apache Corp. into one of the country's largest independent oil and gas companies, died November 8 at his home in Ucross, Wyoming. He was 96.

Chevron Corporation named Steven W. Green president of Chevron North America E&P, effective March 1, 2019. Green succeeds Jeff Shellebarger, who is retiring from Chevron after 38 years of distinguished service. Green, who is currently president of Chevron Asia Pacific E&P, will oversee Chevron's exploration and production activities throughout North America, including the company's significant portfolio of assets.


Emma FitzGerald

Puma Energy Singapore announced the appointment of Emma FitzGerald as CEO. She will succeed Pierre Eladari from January 2 following his previously announced decision to step down. She brings to her new role a wealth of relevant experience from the energy and utility industries. Prior to these roles, she pursued a 20-year career with Royal Dutch Shell where she held a variety of technical, strategic and general management positions in the downstream sector.

THREE60 Energy, a fast-growing energy services provider, has appointed Walter Thain as Group CEO. Thain will be responsible for leading strategic growth across the group, broadening its technical and geographic capability and extending its footprint in key energy markets. Thain comes to THREE60 Energy from Petrofac, where he was most recently MD, West for Engineering & Production Services.


Mohamed Galal

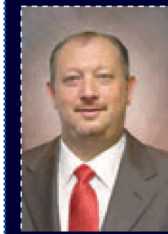
TWMA, provider of specialized drilling waste management services, has strengthened its senior management team with the appointment of Mohamed Galal as regional director for MENA. Galal brings more than 20 years of experience, most recently at Weatherford International as vice president of international accounts. He will be responsible for the strategic growth of TWMA in the region with a particular focus on the UAE, Egypt, Algeria, Kuwait and Oman.

Neptune Energy announced the appointment of Odin Estensen as managing director of its Norwegian business. With more than 28 years' experience in the oil and gas sector, Estensen started his career with Schlumberger before joining Shell in 1990, where he went on to hold various senior roles across Europe, and also to support operations in the Middle East, Africa and Asia. Anne Botne, currently interim country director of Norway for Neptune, will remain with the company and fully resume her head of legal responsibilities.


Thomas B.

Winston & Strawn LLP announced the addition of leading emerging markets attorneys Thomas B. (Tom) Trimble as partner and John David Bryant as counsel in the firm's Washington, D.C. office and as members of Winston's corporate practice. Both hires have considerable experience in Africa and will help Winston in its commitment to expansion into the continent's energy sector.

ULO Systems, a regional grouting contractor for the oil and gas industry, announced the appointment of Colin Reilly as deputy general manager for ULO Systems. Reilly will be based in the company's global corporate headquarters in Sharjah. The company also announced that Zack Agha has been promoted to Group GM for Bukhatir Group and will be based in the group's headquarters in the UAE.


Bryan Ellis

Wild Well Control, a Superior Energy Services company and a leader in well control and engineering services, has named Bryan Ellis as president. Ellis, who has been with Wild Well since 2008, succeeds Freddy Gebhardt as president effective immediately. Most recently, Ellis served as a chief administrative officer overseeing all financial and administrative operations.

Stefan Hantke, CEO of Schneeberger Holding AG in Roggwil. will be chairman of the management team of Schneeberger Group and will be responsible for the entire linear bearings, system technology and mineral casting production business. Adrian Fuchser, managing director of Schneeberger AG Linear Technology will be leaving the company at the end of December. Michael Dvorak will succeed Fuchser, assuming responsibility for the division on January 1, 2019. Michael Dvorak has held various management positions at Schaeffler in Austria, Hungary, Germany and, most recently, the United States.


Miguel Ángel López

Siemens Gamesa Renewable Energy announced some new senior appointments over the period. Miguel Ángel López, current CFO, was appointed new non-executive chairman of the board of directors, replacing Rosa García, effective December 1. David Mesonero will succeed López as CFO. The CEO of the Onshore Business Unit, Ricardo Chocarro, will leave the company. Mark Albenze, CEO of the Service Business unit, will take over in the interim in addition to his current responsibilities. The company also said it will add a new COO function to strengthen focus on cost-out efforts.

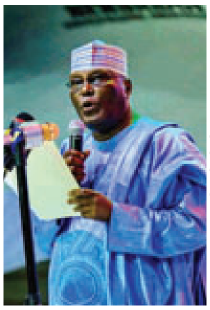
To include a corporate personnel announcement in Moving On, write to *info@petroleumafrica.com.* Preference will be given to Africa-specific appointments and to those companies who have interests within the continent; all others will be included on a space available basis.

Nigerian Election Sparring Begins in Earnest

The next Nigerian presidential elections are scheduled for February 2019 and the rhetoric and dirty tricks are in full swing from both sides as President Muhammadu Buhari and main opposition party challenger, former vice president Atiku Abubakar look to be the strongest in the field of contenders.

The People's Democratic Party (PDP), threatened to go to court as it leveled charges that President Buhari does not hold a high school diploma. Buhari denied the claim but was unable to produce his certificate, although his camp said this is an old charge, having proved the claim false previously.


Source: Nigeria.gov.ng
Muhammadu Buhari


Source: www.atikuabubakar2019.org
Atiku Abubakar

The Senior Special Assistant to the President on Media and Publicity, Garba Shehu, said, "We have read that the failed Peoples Democratic Party is going to court to challenge the President's West African School Certificate (WASC). This is a waste of time because we have the record of this and of higher qualifications obtained by hard work and truly merited by Mr President. This certificate story is an old one. As Femi Adesina stated clearly, it is a settled issue in the courts. To approach the court to pursue a matter long settled by the temple of justice is an abuse of the judicial system. It is shameful, disgusting and disgraceful."

Meanwhile charges have been leveled at Abubakar for not paying his personal taxes by watchdog group Committee for the Protection of Peoples Mandate (CPPM). The activists have demanded that he produce receipts for payment. PDP claims these charges are politically motivated.

A slate of other candidates are expected to run in the election including Obiageli Ezekwesili of the Allied Congress Party of Nigeria (ACPN), Donald Duke of the Social Democratic Party (SDP), Fela Durotoye of the Alliance for New Nigeria (ANN), Kingsley Moghalu of the Young Progressive Party (YPP), and Omoyele Sowore of the African Action Congress (AAC).

Debates are scheduled for both presidential and vice-presidential candidates. The presidential debate is scheduled to take place on January 19, 2019 and will be hosted by the Nigerian Election Debate Group and the Broadcasting Organizations of Nigeria (BON). The vice-presidential candidates are scheduled to debate on December 14

Libyan Elections in the Works

Long awaited elections in Libya could take place in H1 2019 according to Italian Foreign Affairs Minister Enzo Moavero. The Italian minister was speaking after a two-day conference in Palermo aimed at trying to stabilize the North African country.

Libya's two main rival leaders met for the first time in more than five months in Sicily and its prime minister endorsed a UN plan for an election next year.

Ethiopian Women Making Strides

Ethiopia swore in its first female Supreme Court chief, Meaza Ashenafi, on November 1. Ashenafi was a judge on Ethiopia's High Court from 1989 to 1992 and adviser to the UN Economic Commission for Africa. She founded the Ethiopian Women Lawyers Association and started the country's first women's bank.

Ethiopia's new Prime Minister Abiy Ahmed, 42, Africa's youngest head of government, was elected prime minister in April, and has promoted a series of measures to improve gender parity in the country. After a cabinet reshuffling, women now make up half of Ethiopia's ministerial positions, according to a report by NPR.

Trump Words Result in Nigerian Protestor Deaths

According to reports out of Nigeria, the country's army fired at and killed Muslim protestors, citing US President Donald Trump's words as justification for their actions. Apparently, the protestors were throwing rocks when the army soldiers decided to open fire on them. The Nigerian military put the death toll at three, while Amnesty International stated it was over 40 people.

The Nigerian army's official Twitter account posted a video, "Please Watch and Make Your Deductions," showing Mr. Trump's speech in which he said rocks would be considered firearms if thrown toward the American military at the nation's borders. "We're not going to put up with that," Trump said when speaking about immigrants attempting to cross the Mexican border into the US illegally. "They want to throw rocks at our military, our military fights back."

The Nigerian army later deleted the post without explanation.

Bouteflika to Seek Re-Election in 2019

Shockingly to some, but perhaps not to all African citizens, Algeria's long-term president, Abdelaziz Bouteflika, will stand for a fifth consecutive term in next year's elections, the head of his party said in October.

State news agency APS reported that National Liberation Front chief Djamel Ould Abbes said Bouteflika, 81, who suffered a stroke in 2013, would be the party's candidate in voting set for April 2019.

"Bouteflika... is the candidate of the FLN for the presidential election," Ould Abbes was quoted as saying at a meeting with lawmakers from the party. "His candidacy has been demanded by all the FLN cadres and activists across the country," he said.

Bouteflika who has not addressed the nation in over six years, has yet to officially announce his candidacy.

UN Extends Sanctions on Illicit Libyan Crude

The UN Security Council has voted to extend the mandate of the Panel of Experts who oversee the sanctions targeting the illicit export of crude oil and refined products from Libya until February 15, 2020.

The Security Council – which adopted a resolution by 13 votes in favor and none against, with abstentions from Russia and China – underlined that the primary responsibility of the Government of National Accord (GNA) is taking appropriate action to prevent the illicit export of petroleum, including crude oil and refined petroleum products, from Libya.

The UN Security Council "condemns attempts to illicitly export petroleum, including crude oil and refined petroleum products, from Libya, including by parallel institutions which are not acting under the authority of the Government of National Accord," it said in a statement.

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MESSAGE
FROM THE EDITOR

Since 2015 and prior to June of this year, it seemed we had been talking a lot about low oil prices. The five years prior to that high oil prices were all the talk. To close out 2018, low oil prices are a hot topic once again. Since January we have seen a nice steady rise in the oil price, with the Brent crude barrel peaking at about $85 in October, only to tumble down to a 2018 low of under $60 per barrel later in the month; that is lower than the mid to high $60s we started the year with.

These low oil price developments can be disheartening to some operators, especially the smaller independents, who have either made plans to pick up the exploration pace, or indeed have laid down the exploration gauntlet. Further, some may be nervous about finalizing development plans or making an FID.

However, as I write this month's message, OPEC and its non-OPEC partners have just agreed to take 1.2 million bpd off the market for at least six months in an attempt to boost oil prices that have been slumping for almost two months. The cuts will begin from January 1. The barrel price posted an immediate reaction on the news, jumping between 2% and 5% on the various markets. This is expected to settle down again however, and the industry will have to take a wait and see posture to know if the participating countries will stick to their pledged cuts, and what the ensuing result on supplies will be.

On another note, it's that time of year again where many around the globe will be celebrating the various holidays in December and January, myself included. This is always an interesting time in the oil and gas industry as I watch for the breaking news during this traditionally slower part of the year. But it is not slow for everyone, the E&P show must go on and our industry troops remain out there on the frontline; be sure to share a little holiday goodness and cheer with them!

This issue is jam-packed with great reading material; Equatorial Guinea, Gabon, and the Republic of Congo fill the pages of our Africa Focus section. Aquaterra Energy takes a look at how West Africa can benefit from a more modular offshore platform approach in our Local Impact feature. Meanwhile, Muktadir Ur Rahman of Apex Consulting presents the Supermajors Cost Index in Monthly Focus; be sure to find out if cost efficiency has peaked? As always, your comments and suggestions are welcome and can be sent to *info@petroleumafrica.com*.

Happy holidays to one and all!

Dianne Sutherland
Chief Editor

Mellitah Restores Two Wells

Mellitah Oil & Gas recently restored two oil producing wells in spite of security challenges and logistical difficulties at Libya's Wafa field. After a thorough study conducted by the company's Reservoir Engineering Department, in coordination with NOC's Reserve Development Department, engineers were able to apply the Schlumberger Coiled Tubing Velocity String technique to well A52 which had been closed since July 2017 due to continuous low wellhead pressure, preventing the flow of crude oil.

Pumping gas produced by one of the gas wells through well A52 production pipelines ensured the flow of crude oil. The company succeeded in restoring the well, with a daily production rate of 2,600 bpd. The same technique was applied to well A20 which successfully restored with a daily production rate of 1,200 bpd.

The company is now conducting studies on several other wells selected by departmental specialists in the hope of applying this technique following the success at the Wafa field.

BP and ENI to Explore Libya in Q1

BP and ENI expect to begin joint exploration in Libya in Q1 2019, according to CEO Bob Dudley. "I'm not sure about this year since it takes time to set up offshore rigs but Q1 for sure," Dudley was cited by Reuters as saying.

Earlier ENI agreed to buy half of BP's 85% stake in a Libyan oil and gas license and become the operator of the exploration and production license in the country.

Dudley said the agreement with ENI did not mean BP was thinking of pulling out of Libya. "We remain committed and have plans to expand," he said.

Libya Plans Qaddafi Era Production Target

Libya expects its production to rise to the levels seen during former ruler Muammar Qaddafi's reign, according to the chairman of the state-run firm NOC, Mustafa Sanalla. To achieve this the country plans to refurbish its pipeline network and raise output at some fields to reach a target of 1.6 million bpd. Currently Libya is pumping at a rate of 1.25 million bpd.

"We've put together a plan to boost field production, including pipeline maintenance and addition of new pipelines," Sanalla said. He went on to say that the goal was to reach 1.6 million bpd by the end of 2018 and increase from that level.

While NOC officials have sought to increase oil and natural gas output, security issues and lawlessness have plagued the country's reemergence as one of the continent's producing powerhouses.

Mubadala Joins ENI on Nour North Sinai Offshore

ENI and Mubadala signed an agreement for the sale of a 20% participating interest out of ENI's share in the Nour North Sinai Offshore concession in Egypt to Mubadala Petroleum, a wholly owned subsidiary of Mubadala Investment Company.

In the concession, which is in participation with EGAS, ENI holds an 85% stake in partnership with Tharwa Petroleum Company, which holds a 15% stake of the contractor's share where ENI and Tharwa are collectively the contractor.

The completion of the transaction is subject to the fulfillment of certain standard conditions, including all necessary authorizations from Egypt's authorities.

Nour is located in the prolific East Nile Delta Basin of the Mediterranean Sea, approximately 50 km offshore in the Eastern Mediterranean, in a water depth ranging from 50 to 400 meters, covering a total area of 739 sq km. ENI and

Eland Tests and Drills in Nigeria

Eland Oil & Gas has completed drilling operations on the Opuama-11 well. The well has now been handed over to the Opuama field production team. The company, through its JV subsidiary Elcrest Exploration and Production Nigeria Ltd (Elcrest), is now flow testing the well into the production facilities and on to export.

The long string producing from the deepest of these reservoirs, the D4000, flowed at 1,610 bpd on a 24/64" choke with a flowing tubing head pressure (FTHP) of 1,450 psi and the short string, producing from the D3500, flowed at 2,453 bpd on a 28/64" choke with a FTHP of 609 psi.

It is expected following completion of testing that stabilized initial production from Opuama-11 will be between 4,000-6,000 bpd, in-line with previous guidance.

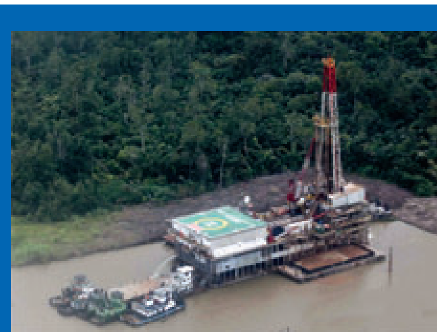
As previously announced, the Opuama-7 sidetrack well has experienced increased water-cut from the current D2000 completion. A production log was run in order to confirm water containment options ahead of a future planned re-completion on the D1000 reservoir, the well's primary target.

Aggregate production from the Opuama field is currently 26,325 bpd. Following completion of Opuama-11 testing, aggregate production from the Opuama field is expected to be approximately 30,000 bpd.

Upon completion of Opuama-11 drilling operations, the OES Teamwork Rig mobilized to the Gbetiokun field where it will re-enter the Gbetiokun-1 well and drill the Gbetiokun-3 well as part of the initial phase of the field development.

The Gbetiokun field will be brought on stream through an early production system (EPS). The Gbetiokun EPS will receive production from the existing Gbetiokun-1 well, which will be completed to produce from the E2000 and E6000 reservoirs, as well as the planned Gbetiokun-3 infill well, which will produce from the D9000 and E7000 reservoirs. Initial production through the Gbetiokun EPS is estimated to be approximately 15,000 bpd.

At the Ubmina field, workover operations on the Ubima-1 well have now been completed and the rig has been demobilized. Further to the release in September, in which the company announced that the F7000 reservoir was tested at flow rates



Source: OES

OES Teamwork in Nigeria

of up to 2,500 bpd on a 24/60" choke, testing operations on the D1000 reservoir at 4,908 ft subsea were completed. During the test, sand production prohibited flow to surface, but an oil sample with about 15 API gravity was recovered. The JV will now evaluate options for the further appraisal and potential development of the D1000 sands.

A dual completion has been installed and a production test will be carried out on the E1000 / E2000 reservoirs to further assess volumes and productivity. Initial results from the production test are expected in the coming period and the company will update the market once these results are evaluated.

Tharwa Petroleum Company are currently carrying out the drilling of the exploration well as foreseen in the first exploration period of the Nour concession.

Bahr Essalam Phase 2 Complete by Year End

Following a meeting with ENI CEO, Claudio Descalzi, Libya's NOC chairman Mustafa Sanalla revealed that the Bahr Esslam Phase 2 project was nearing completion. Sanalla said that project was expected to be completed by year end.

Sanalla and Descalzi discussed ongoing operations by the Italian firm, including plans for the seven remaining wells. The first wells in phase two of the development of Bahr Essalam came online in July.

Source: NOC

Also under discussion was the compression capacity upgrade project at the Wafa plant. First gas from the project is expected to come onstream in a matter of days. According to a statement by NOC, the Wafa plant was "a successful joint project in challenging conditions in Libya's remote interior."

The two men also discussed opportunities to increase production, investment and exploration, and the importance of sustainability in all activities.

Wafa Gas Compressor Project Nears Completion

Libya's NOC, reported that the Wafa field's gas compression project is almost complete. The project is part of the state-run company's efforts to secure target quantities of natural gas and the optimal utilization of reserves available on the Wafa field located on NC-169.

The project, undertaken by the field's operator, Mellitah Oil and Gas Co. (MOGCO), calls for the installation of four new gas compressors. The new compressors will be used to compensate for the low pressure of the reservoir and to stimulate wells to produce additional quantities of gas.

The completion of operating tests for gas compressor D and the first fire of it was scheduled to take place on October 28 and the first gas flows from compressor D were expected on November 4. Operating tests and gas production from the second compressor C were expected to complete by mid-November, two weeks after the first compressor is operational.

The additional quantity of gas resulting from the start up of the first compressor is estimated at between 25 and 30 Mmcf/d. NOC estimates that this additional quantity of gas will increase to between 70 and 80 Mmcf/d following the operation of the second compressor, and up to 100 Mmcf/d following the third. According to the project implementation plan, the third and fourth compressors A and B will become operational in February and March 2019 respectively.

ENI, Sonatrach and Total to Venture Offshore

In Algeria ENI, Sonatrach, and Total entered into two agreements on the sidelines of the Algeria Energy Summit. One of the agreements has the three firms teaming up to explore offshore Algeria in a virtually unexplored geological province.

In parallel, ENI and Total will also pursue obtaining exploration permits that will allow for the rapid completion of an assessment of the hydrocarbon potential.

ENI's CEO, Claudio Descalzi, said: "Together with Sonatrach and Total, we will have the opportunity to explore the deep waters of the Algerian offshore, a virtually unexplored geological province where ENI will be able to contribute by leveraging its experience in the Eastern Mediterranean and its inventory of advanced exploration technologies."

Vitol/Africa Oil/Delonex on Nigerian Deepwater Adventure

A consortium made up of Vitol, Africa Oil and Delonex are moving into Nigeria's offshore deepwater arena, picking up stakes in major producing assets. The three have entered into a Share Purchase Agreement (SPA) to acquire a 50% interest in Petrobras Oil and Gas B.V.(POGBV) for $1.407 billion. BTG Pactual E&P B.V. will continue to own the remaining 50% of POGBV.

The transaction is subject to customary conditions precedent. The primary assets of POGBV are an indirect 8% interest in OML 127, which contains the producing Agbami field, operated by affiliates of Chevron, and an indirect 16% interest in OML 130, operated by affiliates of Total, which contains the producing Akpo field and the Egina field, which is expected to commence production by the end of 2018. Current production of 368,000 bpd is anticipated to increase to over 568,000 bpd by H2 2019.

The agreed base purchase price of $1.407 billion, is on a cash and debt free basis as of the effective date of January 1, 2018. A deferred payment of up to $123 million may be due to the Seller depending on the date and ultimate OML 127 tract participation in the Agbami field, which is subject to a redetermination process.

Libya Restarts Field in East

Libya's AGOCO, a subsidiary of state-run NOC, restarted production at the al-Bayda oilfield in the eastern part of the country. This is the latest field to restart following the heavy fighting that took place in mid-2018. The field has a current capacity of about 12,400 bpd.

The restart of production will aid in NOC in its plan to reach crude production totals of 1.6 million bpd by the end of the year. The country has not seen its flows hit this level since former ruler Muammar Qaddafi was still in office.

In June, an armed group attacked the eastern ports of Es Sider and Ras Lanuf, forcing NOC to declare *force majeure* for several weeks.

Red Sea Acreage Up for Grabs

International oil and gas firms with an interest in exploring in Egypt's Red Sea will get their chance to gain access to acreage. According to the country's Minister of Petroleum, Tarek El Molla, the government plans to invite international players to explore for oil and gas in its territorial Red Sea waters before the end of the year.

El Molla said the process would be announced after the processing of seismic data collected by Schlumberger and TGS. The two companies started work in the area in March and the data collected, the Ministry of Petroleum said, are being processed. The Ministry said it expects huge interest.

Egypt became an important spot on the international oil and gas map after major finds were made off its Mediterranean coast. The discoveries include the Zohr Field, which contains confirmed reserves of 850 Bcm of gas.

Zohr was one of four major gas wells that came online in Egypt in the past year, allowing Egypt to achieve self-sufficiency with 6.7 Bcf of daily production. The government stopped imports in October and is expected to resume gas exports next year as new developments come online and/or ramp-up production.

Foreign and local companies spent $27 billion in developing the four wells. The willingness of international companies to invest such huge amounts of money in Egypt boosted the country's image in international oil and gas markets, the Petroleum Ministry said.

"International oil and gas companies know that this country has a lot to give them," said Hamdi Abdel Aziz, the spokesman of the Ministry. "This is why we expect high interest among international companies in the expected bid for exploration in the Red Sea."

Abdel Aziz described data collected by Schlumberger and TGC as very positive."There are strong possibilities for the discovery of large amounts of gas and crude oil in the area," Abdel Aziz said. "This will be very encouraging for international oil and gas companies."

Total Plans New Wells for Block 17

Total's Block 17 offshore Angola will see 13 wells drilled to help the company maintain production levels. The wells will help the French firm keep levels at 400,000 bpd until 2023.

The wells, which will connect marginal fields to existing floating platforms, would be divided between two projects, Total said in a statement.

CLOV 2 will involve drilling seven additional wells to produce 40,000 bpd. First oil is expected in 2020. While six wells will be drilled at Dalia 3 to produce 30,000 bpd. Oil from Dalia 3 is expected in 2021.

The projects, along with the previously announced Zinia 2, will enable Total to maintain production from Block 17 of more than 400,000 bpd, the company said.

ENI and Sonangol Sign Block 15/06 Amendment

ENI and Sonangol have signed an amendment to the Block 15/06 PSC which defines the new perimeter of the block, now covering an additional area of 400 sq km on the west side. This is in line with ENI strategy to increase exploration activities in the country, chasing opportunities nearby the existing producing hubs.

Following the discovery of Kalimba 1 in June 2018, ENI set up an accelerated exploration program and already started the drilling activities with a schedule of four exploration wells. In the event of success, this strategy will enable a fast-track development of these new resources, leveraging on synergies with existing infrastructure and significantly reducing their time to market.

Furthermore, new start-up already achieved during 2018, and expected in the coming months, will increase production by up to 50,000 boepd, with production at plateau reaching a peak of 170,000 boepd early next year.

Sonatrach Awards Petrofac Tinhert Job

Sonatrach awarded a contract worth $506 million to Petrofac to boost gas output at the Tinhert field by 4.7 Mmcm/d, Sonatrach's CEO Abdelmoumen Ould Kaddour said. The value was about $100 million less than originally announced. Kaddour said the difference in value was because part of the work had been awarded to Algeria's GCB.

Angolan Parliament to Submit New Local Content Law

The Angolan parliament is expected to submit a new local content law for the oil and gas sector. The law will aim to establish a framework of clear, feasible, and unbureaucratic procedures to allow the application of better local content principles.

The announcement was made by Frederico Cardoso, Minister of State and Head of the Civil House of the President of the Republic at the opening of the 2nd African Conference on Local Content in the Oil and Gas Industry. According to Cardoso, it is "essential to end the inefficiency of local content laws" in the country. He assured that the new regulations will answer the outstanding questions in this direction. Once the new law is approved, it will include security commitments and legal commitments to local companies. It will open the door to multiple opportunities for them in the field of technical, technological, employment and human resource development.

ENI Picks up Stakes in Three Algerian Blocks

A deal was signed between ENI and Sonatrach on the sidelines of the Algeria Future Energy Summit that will see ENI take a 49% stake in three concessions in the onshore North Berkine Basin.

The Chairman and Director General of Algeria's state oil company Sonatrach, Abdelmoumem Ould Kaddour, and the CEO of ENI, Claudio Descalzi, signed the agreement on behalf of their respective companies.

The agreement, which was signed at the Algeria Future Energy Summit in Algiers, will cover three areas: Sif Fatima II, Zemlet El Arbi, and Ourhoud II. Sonatrach will retain a 51% stake.

The licenses cover a total area of 8,500 sq km and are located in the North Berkine Basin where all the company's current production assets are also located.

The two firms will carry out an important exploration program in order to develop the reserves on the three blocks, estimated at 145 million boe. Production is expected to start by the end of 2020.

The development will benefit from synergies with existing facilities in the area, as well as new projects and infrastructure that are currently under construction. These include a 180 km-long gas pipeline that is being fast-tracked and will connect the oil fields of BRN and MLE.

OML 40 Renewal Approved with Hefty Bonus

Eland Oil & Gas, through its JV subsidiary Elcrest Exploration and Production Nigeria, announced that the Petroleum Ministry had consented to Elcrest's renewal of its equity participation in OML 40 for a further 20 years. This took effect on October 22.

The consent is conditional on an Elcrest payment of a Renewal bonus of $6.3 million within 90 days and a commitment from the OML 40 JV to gas monetization and additional sales of 25 Mmcf/d with the gas sales agreement to be signed within five years. The company is currently preparing the title deed for OML 40 to conclude the renewal process. All other conditions precedent to the consent have been met.

Rockhopper Updates Abu Sennan

Rockhopper Exploration updated its activities on Egypt's Abu Sennan concession. Currently the concession is producing at a rate of around 3,800 bpd of oil, which is in line with H1 rates.

The company participated in drilling the development well, the Al Jahraa 6. The well was successful, not only in its primary objective as an Abu Roash-C infill oil producer but also encountered good oil shows in the Abu Roash-D, E, G and made a new oil discovery in the deeper Bahariya section. The Bahariya formation was put on test in late-September and, after clean-up, is producing in excess of 550 bpd with a stable water cut of 22%. This represents the first commercial oil production from the Bahariya formation within the Abu Sennan concession.

The well has been completed to allow potential future production from Abu Roash G and C levels. The company believes that the Bahariya discovery de-risks additional exploration targets at the same level elsewhere in the concession.

The second Al Jahraa field development well, the Al Jahraa-10 well, reached total depth on October 16 in the Abu Roash-F Formation. Oil pay was calculated in the Abu Roash-C and Abu Roash-D levels. Operations are ongoing to test both levels and put the well into initial production on the most productive horizon.

The Abu Sennan exploration concession amendment agreement was approved by the Egyptian Parliament and was signed by the Minister of Petroleum in September. The first phase of the concession was triggered upon signing of the agreement and has a set three-year duration with an expiry date.

Exploration well ASZ-1X located on Prospect S was spudded using the rig EDC-53 on November 8, and will be the first of two commitment wells to be drilled in the first phase of the new concession. The primary objective of well ASZ-1X is the Abu Roash-C reservoir sand that produces in the neighboring Al Jahraa field. The deeper Abu Roash reservoirs present secondary targets.

Aquaterra Wins Nigeria Gig

Aquaterra Energy, in conjunction with Maerlin Nigeria Ltd, its local partner, was awarded a contract by FIRST Exploration and Petroleum Development Company Ltd (FIRST E&P) to design, engineer and install two non-identical Sea Swift conductor-supported offshore platforms in the Niger Delta Basin.

The platforms are destined for the Anyala and Madu fields within Oil Mining Leases 83 and 85 offshore Nigeria. The Anyala and Madu field project scope will develop approximately 185 million barrels of oil and 637 Bcf of gas reserves.

Aquaterra Energy will manage the end-to-end project scope with engineering and onsite fabrication support being performed in Nigeria. The work includes structural design, topsides engineering, equipment selection, procurement, fabrication management and logistics. Once complete, the platforms will be installed in water depths of 35-meter to 55-meter with first oil expected in late 2019.

Sonatrach Removes Equipment from Libya

Algerian state-run firm has repatriated its equipment from its acreage in Libya. According to Libyan media reports, the Algerian firm removed its equipment used in the development work of an oil block located on the border with Algeria, in the coastal basin of Ghadames. The equipment was removed due to the current security situation in the region.

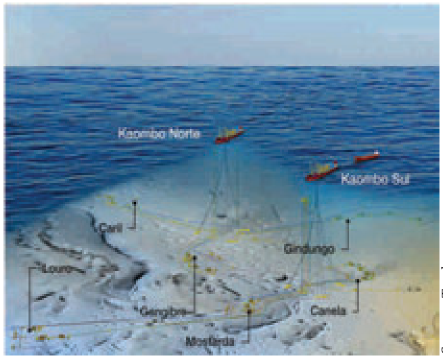
Sonatrach's repatriation of its equipment was preceded by the evacuation of its employees. The company had completed drilling seven production-ready wells before deciding to retire temporarily until security conditions improved, reported The Libya Observer.

No further details were offered by Algerian or Libyan authorities. It is also unclear whether the violence has resumed in this zone where a lull was observed a few months ago.

Angola and Total Inaugurate Kaombo

Angola saw the inauguration of Total's Kaombo project offshore the country on Block 32. While the project came on stream in July, the inauguration was held just recently and was attended by the Angolan State Minister for Economic and Social Development, Manuel Nunes Junior, the Chairman and CEO of Total, Patrick Pouyanné, and the Chairman of the Board of Directors of Sonangol, Carlos Saturnino.

During the ceremony, Total also announced the continuation of its development program in Angola, following on from its launch of the Zinia 2 project in mid-2018.



Source: Total

Total, along with its partners, has notably taken two investment decisions on Block 17, to develop satellite fields that will be tied back to existing infrastructures and will quickly bring additional production. The CLOV 2 project requires the drilling of seven additional wells and the Dalia phase 3 project. The Dalia will see an additional six wells drilled.

Zinia 2, CLOV 2 and Dalia 3 will develop 150 million barrels of additional resources to maintain the Block 17 production plateau and further extend the profitability of this prolific block, with over 2.6 billion barrels already produced.

The Kaombo is the biggest offshore development in Angola. The first FPSO, *Kaombo Norte*, came on stream in July 2018, with a production capacity of 115,000 bpd. The start-up of the second FPSO of similar capacity, *Kaombo Sul*, is expected next year. The overall production will reach an estimated 230,000 bpd at peak and the associated gas will be exported to the Angola LNG plant.

A total of 59 wells will be connected to the two FPSOs through one of the world's largest subsea networks. Together, they will develop the resources of six different fields (Gengibre, Gindungo, Caril, Canela, Mostarda and Louro) over an area of 800 sq km in the central and southern part of the block.

Panoro Contracts Rig for Sfax Well

Panoro Energy signed a Heads of Terms with Compagnie Tunisienne de Forage (CTF), Tunisia's state-owned drilling contractor, for use of the CTF-4 onshore rig. Panoro will use the rig to drill its Salloum West-1 well (SAMW-1) located on the Sfax Offshore Exploration Permit (SOEP).

The spud date of the SAMW-1 well is anticipated to be in H1 2019 and is subject to the entry into a second renewal period of the SOEP for a period of three years, and the subsequent approval of the final drilling program and budget by state firm ETAP. Advanced discussions for the renewal are ongoing with the Tunisian Authorities.

The SAMW-1 well, to be directionally drilled from the shore as a deviated well, comes only three months after the closing of the acquisition of DNO Tunisia.


Source: Panoro

The primary objective of the SAMW-1 well is the Bireno formation, at approximately 3,200 meters vertical depth, where the company has identified, based on 2D and 3D seismic data, what it believes to be an extension of the Salloum structure to the west. The SAMW-1 well will target an independent fault compartment up-dip from the Salloum-1 well which was drilled by British Gas in 1992 and tested the Bireno formation at a rate of 1,846 bpd.

The objective of the SAMW-1 well is to prove up additional resources in the vicinity of the Salloum-1 well and subsequently fast-track the development of Salloum through a tie-in to existing adjacent oil infrastructure.

The decision to drill this new well is supported by rig availability, cost-savings due to drilling equipment for the well already being owned and stored in Panoro's Sfax warehouse, existing 2D and 3D seismic covering the SAMW-1 location, close proximity to the Salloum-1 discovery well, the existing adjacent oil infrastructure, and a high chance of success.

FAR Looks for Extension in Kenya

During Q3 FAR Ltd. submitted a request to Kenya's Ministry of Petroleum and Energy for a further non-operations extension to the current Permit Year for the L-6 block. The JV continues to be prevented from gaining land access across vital areas of the onshore block, which has indefinitely suspended the start of the onshore work program.

While FAR awaits Ministerial approval for the current extension request, it has secured a 24-month renewal to the existing Environmental and Social Impact Assessment License in effect across the onshore areas of Block L-6.

In related news, Pancontinental Oil and Gas remains in default under the terms of the joint operating agreement on payments to FAR.

Anadarko Awards Mozambique EPCI Contract

Anadarko Mozambique Area 1, LTDA, a wholly owned subsidiary of Anadarko Petroleum, on behalf of the co-venturers in Mozambique's Offshore Area 1, selected the consortium consisting of TechnipFMC and VanOord as the preferred tenderer for the EPCI of the offshore subsea system for its Mozambique LNG project.

"Selecting the preferred tenderer for the EPCI contract for the offshore subsea system is another major step for the Anadarko-led Mozambique LNG project in moving toward an expected FID in H1 2019," said Mitch Ingram, Anadarko Executive Vice President, International, Deepwater and Exploration. "TechnipFMC and VanOord bring additional proven experience to the project and further demonstrate our continued commitment to advancing this important project toward first cargoes."

APC and its partners have discovered more than 75 Tcf of natural gas resources in the Prosperidade and Golfinho-Atum complexes in Mozambique's Offshore Area 1, which will be used to feed an onshore LNG terminal.

Total and Sonangol in Talks for STP Block

In Sao Tome and Principe, the National Petroleum Agency (ANP) began negotiations with a consortium consisting of Total and Sonangol to sign an oil exploration contract for Block 01 in the Exclusive Economic Zone (EEZ).

These negotiations are the result of the interest shown by Total E & P for oil exploration in this block, following a public call for tenders launched by ANP last May.

Total's ROC Production on the Rise

Total saw its production in the Republic of Congo (ROC) rise, according to a company official. Martin Deffontaines, GM of Total E&P Congo told Bloomberg that its production in the West African country exceeded expectations.

"Its production is far more than what we had anticipated," Deffontaines said.

The company is pumping 200,000 bpd and the ROC is targeting a 65% increase in production this year.

Polarcus Wins 3D Job in West Africa

Seismic firm Polarcus was awarded a contract in West Africa. The contract is for a 3D marine seismic acquistion project.

The award comprises two surveys of approximately three months each, with the first survey expected to commence in Q2 2019 and the second survey in Q4 2019.

BP and Kosmos Launch EIA in EEZ

The consortium of BP and Kosmos Energy have launched environmental impact studies on newly acquired blocks 10 and 13 in Sao Tome and Principe's Exclusive Economic Zone (EEZ). The island nation's state-run oil company, ANP, controls 15% participation on each block.

The firms have a 28-year exploration and production contract. The first years will focus on seismic studies, followed by development and production if reserves are discovered.

Block 10 is located at a water depth of 2,500 meters within an area of 6,839.6 sq km and Block 13 is located at a water depth of 3,000 meters and covers an area of 6,776.9 sq km.

Invictus Puts a Damper on Zimbabwe Discovery Talk

Australian-listed Invictus Energy denied reports of an oil discovery in Zimbabwe where it had been exploring. Zimbabwean president, Emmerson Mnangagwa, had told reporters that Invictus had found oil and gas deposits in the Muzarabani area of northern Zimbabwe and had agreed to enter a PSA with Zimbabwe once the project reached commercial production.

The company, however, said that deposits were not yet discovered but there were indications of a "working petroleum system" which could only be confirmed by a planned exploration well.

"The prospective resource estimate for the Muzarabani prospect relates to undiscovered accumulations which have both a risk of discovery and a risk of development," said Invictus. "Although the Cabora Bassa Basin possesses all the elements for a working petroleum system, a discovery can only be confirmed through drilling of an exploration well."

Mines Minister Winston Chitando said the well would be drilled in 2020 at a cost of $20 million and said the Muzarabani project was the largest undrilled onshore resource in Africa.

Madagascar Launches Licensing Round

Madagascar, through state-run firm OMNIS, will be promoting its oil and gas potential to attract new investment in the sector. The state-run firm worked with TGS and BGP to create an attractive environment for offshore exploration. The announcement was made by Voahangy Nirina Radarson, Director General of OMNIS on November 6 at the NOC Prospect Forum.

The round opened November 7 offering 44 offshore blocks in the Morondava Basin. The round will close on May 30, followed by a three-month awarding period. For interested parties, roadshows will be held in Houston and London during February. Existing seismic and well data will be available for viewing at the TGS offices, in London and Houston; data packages will also be made available for clients.

Exploration in Madagascar began in the early 1900s with the discovery of hydrocarbon-rich sedimentary basins in the west, including the Tsimiroro heavy oil field and the Bemolanga tar sands. After over 100 years of exploration, the offshore of this frontier region remains largely under-explored. The Island shares a maritime boundary with Mozambique, a hydrocarbon province where large quantities of natural gas have been discovered.

Studies conducted on new data, in collaboration with TGS and BGP, suggest there is significant potential for future discoveries offshore.

Tlou Successfully Drills First Lesedi CBM Well

Tlou Energy successfully drilled its first well in the Lesedi CBM Project in Botswana. The Lesedi 3P was spud on October 16 and successfully reached a total depth of 575 meters.

Wireline logs were acquired over the open hole interval of Lesedi 3P. The well intersected the Lower Morupule coal seam, which is the target seam for dual lateral wells, planned to be drilled for approximately 700 meters in-seam, which will then intersect with Lesedi 3P.

The rig was released from location and then set up at the Lesedi 4P location. Lesedi 4P was spudded on November 4. Operations at Lesedi 4P will follow the same program as for Lesedi 3P. The well is planned to be drilled to a proposed total depth of approximately 580 meters.

Total Preparing to Spud in South Africa

South Africa is set to see some drilling action from Total E&P in the near future. The company will be drilling on Block 11B/12B, which could be one of South Africa's most prospective oil exploration assets in Africa with multi-billion-barrel potential and a high chance of success. Total is the operator of the block.

The *Odfjell Deepsea Stavanger* semi-submersible rig is mobilizing from the North Sea to spud the Brulpadda well on Block 11B/12B in December. A discovery would be transformational for the South African oil sector, which has been dormant due to political uncertainty.

Source: Odfjell

Deepsea Stavanger

There are rumors that Qatar Petroleum beat out Shell to take a 25% stake in the blocks and the transaction has recently closed. CNR also holds a 20% stake in the block.

Total has fulfilled its obligation to date regarding the Environmental Management Plan (EMP). As a part of the work program the partners will reenter the Brullpada-1AX (3522C-12-3-64-1) well which was suspended in 2014 in order to establish any traces of hydrocarbons. The well is located offshore approximately 180 km south of Mossel Bay in the South Outeniqua Deepwater Basin. The drilling activity is expected to last for approximately three to four months depending on weather conditions.

The wellhead survey is estimated to start around end November and is scheduled to last no more than one week.

Kosmos Goes to Namibia

Kosmos Energy expanded its position in Africa picking up acreage in southern Africa. The company entered into a strategic exploration alliance with Shell to jointly explore in Southern West Africa.

Initially, the alliance will focus on Namibia, where Kosmos has completed the farm-in to Shell's acreage in PEL 39, and then moves northwest to Sao Tome & Principe where it has entered into exclusive negotiations for Shell to take an interest in Kosmos' acreage in Blocks 5, 6, 11, and 12.

As part of the alliance, the two companies will also jointly evaluate opportunities in adjacent geographies. This alliance is consistent with Kosmos' strategy of partnering with supermajors to leverage complimentary skillsets. Shell has deep expertise in carbonate plays, while Kosmos brings significant knowledge of the Cretaceous in West Africa. Furthermore, by working with Shell, Kosmos has a partner with the expertise to move exploration successes through the development stage efficiently.

Gambia's Samo-1 Disappoints

The first well drilled off the coast of Gambia in decades was not the success hoped for. FAR Ltd. reported that its Samo-1 well offshore was drilled to a total depth of 3,240 meters and wireline logging is nearing completion. The well operations to date have been conducted safely, efficiently, ahead of schedule and within budget.

Interpretation of the wireline logs so far indicates that the main target horizons are water-bearing. Oil shows were encountered at several levels indicating that the area has access to an active hydrocarbon charge system. The well also encountered excellent reservoir and seal facies, indicating that all the key components for a successful trap are present. As the first offshore well in 40 years and the first modern well, the data that has been collected at Samo-1 and the ongoing interpretation will be critical to unlocking the hydrocarbon potential in the area. The well will be plugged and abandoned, consistent with the plan for this exploration well.

The government of The Gambia confirmed a six-month extension to the current license to end June 2019 to allow for evaluation of the Samo-1 well results.

CGG Fast-Tracks Mozambican 3D

CGG announced during Africa Oil Week that the fast-track 3D seismic data from its recent Mozambique multi-client survey in the outer Zambezi Delta Basin is now available for license. Interested international oil companies with an Africa focus can view the high-end data set in CGG data rooms in anticipation of the country's 2019 licensing round.

The data covers a 15,400 sq km area over Block Z5-C and Block Z5-D and surrounding open acreage. It was acquired as part of a multi-client program agreed between CGG and Mozambique's Instituto Nacional de Petroleo (INP) in 2017.

Final PSDM deliverables will be released in Q4 2019 and be complemented by a JumpStart™ integrated geoscience package as well as a geological regional study (2017 East Africa Robertson Study), and the Robertson New Ventures Suite of exploration screening tools.

Tullow Picks Up Stakes Offshore Comoros

Discover Exploration Comoros has signed a binding agreement to farm out a 35% working interest in its PSC covering Blocks 35, 36 & 37 offshore Comoros to Tullow Comoros. As part of the transaction, Tullow will become the operator, and will partly carry Discover for a 3D seismic survey and the first exploration well. The transaction is subject to governmental consent.

Simultaneously, Discover has signed a binding agreement to acquire (subject to certain conditions) the entire issued share capital of Bahari Resources, its 40% joint venture partner in the Comoros PSC.

Following completion of both transactions, Discover will hold a 65% non-operated working interest in the Comoros PSC (through its wholly-owned subsidiaries Discover Exploration Comoros and Bahari), while Tullow will hold the remaining 35% and operatorship (through its wholly-owned subsidiary Tullow Comoros Limited).

The Comoros PSC covers a deep-water area of 16,063 sq km and is outboard of circa 200 trillion cubic feet of gas in place discovered in Rovuma Areas 1 and 4, offshore Mozambique.

South Africa Eases Licensing Moratorium

Firms who have been looking to explore in South Africa received some good news recently, the government will be going over applications soon. South Africa plans to ease its moratorium on gas and oil exploration licenses to allow exploration and production applications already in the system to be granted. The moratorium was enacted earlier this year.

"This amendment will ensure that applications currently in our system are processed and granted," Mineral Resources Minister Gwede Manta she told an oil and gas industry meeting.

Uganda Plans 2019 Licensing Round

Uganda plans to launch a new licensing round for oil exploration in mid-2019. According to Ernest Rubondo, executive director of the Petroleum Authority of Uganda, the licensing round will kick off in May 2019.

"We will have a road show first and then we will start the bidding round in May next year," Rubondo was cited by Reuters as saying on the sidelines of an industry event in Cape Town.

Total and CNOOC plan to begin production in Uganda but will miss the government's target of 2020. Both firms say that first oil flows will begin in 2021.

Total Joins Namcor and Impact Offshore Namibia

Namibia's state-run oil firm, Namcor, revealed that two Joint Operating Agreements (JOA) were executed with Total and Impact Oil in Cape Town. The JOA has Total joining Impact and Namcor in deepwater Block 2913B.

Block 2913B covers approximately 9,000 sq km 300 km offshore Namibia in a water depth of 3,000 meters. The acreage lies along the western toe of the Orange River delta, where deep marine fan sands are contained within large structural traps. While Block 2913B is located 150 km west of the Kudu Gas field, recent exploration wells along the outer fringes of the Orange Basin have demonstrated that there exists a rich oil prospective zone running through the block.

In addition, the Namcor and Total partnership concluded a JOA in respect of Block 2912, also located in the Orange Basin. NAMCOR holds a 15% carried interest in the Block 2912 and Total holds the remaining interest. Total will act as operator of both Block 2913B and Block 2912.

Sasol Picks Up New Acreage in Mozambique

Sasol has been awarded two new licenses for gas exploration in Mozambique. The South African firm has been given the greenlight to explore on acreage covering more than 3,000 sq km in southern Mozambique.

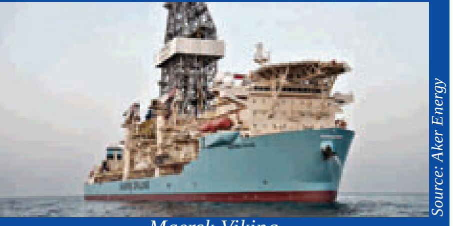
The company has also been awarded a block offshore the country in the Angoche Basin, covering an area of about 5,100 sq km. Sasol holds 70% interest in the first block and 25.5% in the second.

According to Business Day, Sasol's executive VP for upstream, Jon Harris, said on the sidelines of the Africa Oil Week conference, that the company was excited about the block in southern Mozambique because it was adjacent to its gas-producing Pande and Temane fields.

"We know there is a hydrocarbon system in the vicinity of this block so we know there is a very good chance we might find some more gas." The production license for Pande and Temane, which was due to expire in 2022, has now also been extended for 20 years, Harris said.

Maersk Viking Arrives Offshore Ghana

In Ghana, Aker Energy, saw the arrival of the *Maersk Viking* drill ship on the Deepwater Tano Cape Three Points (DWT/CTP) license off Ghana.



Source: Aker Energy

Maersk Viking

The vessel will drill the Pecan-4A evaluation well when all preparations are complete, says Jan Helge Skogen, head of the Norwegian company in Ghana. The work is expected to be completed at a water depth of 2,674 meters approximately 70 miles off the coast of Ghana.

The contract between the two parties contains a clause stating that, if successful, the partners may drill two additional wells.

Drilling was expected to begin imminently and last between 30 and 35 days.

Predator Picks Up Guercif in Morocco

Predator Oil & Gas Holdings saw its application for an exclusive license for onshore acreage in northeastern Morocco accepted by the government. Predator was awarded a 75% stake in the 7,269 sq km Guercif I, II, III, and IV permits in the east of the Gharb Basin. ONHYM, Morocco's state-run firm, will hold the remaining 25% of the license. The license covers an eight-year period, divided into three phases.

SNE Development Plan Submitted

Cairn Energy, operator of the SNE field offshore Senegal, submitted the Development and Exploitation Plan to the government. The company expects to see the plan approved later this year.

The Development and Exploitation plan outlines the full multi-phase development of oil and gas. The field will be developed in a series of phases with plans for ~500 million barrels of oil and gross production of 100,000 bpd of oil with first flows targeted for 2022. Following the establishment of oil production, commercial gas sales to Senegal are expected to commence.

The tender responses for the FPSO facility and supporting subsea infrastructure have been received and are under evaluation and short-listing ahead of the FEED planned later this year. In parallel with the detailed engineering work, an Environmental and Social Impact Assessment study has been submitted to the National Technical Committee.

The submission of the Exploitation Plan coincides with the opening of the MSGBC conference for the oil and gas industry in Dakar, Senegal.

In addition, Cairn revealed that Woodside Energy, one of the JV partners, has exercised its option to become operator of the SNE field. Work is already well underway to facilitate transfer of operatorship which is now subject only to government consent.

Dragon Puts Africa on Shopping List

Dragon Oil, a subsidiary of Dubai-based government firm Emirates National Oil Company (Enoc), plans to spend around $500 million on acquisitions in 2019. According to the company's chief executive, countries in Africa are on its shopping list.

"We will drill two wells in Egypt in early next year and we have a commitment to drill one well in Tunisia by Q1 2019. In West and North Africa, we are talking to Ghana, Algeria and Egypt," Ali Rashid Al Jarwan said while speaking on the sidelines of Gas and Oil Technology (Gotech) exhibition.

"For 2019, our acquisition target will be between $350 million to $500 million. We are very ambitious about expanding our existing assets and adding new ones," Al Jarwan added.

Gabon Launches Licensing Round

Gabon launched its highly-anticipated 12th Shallow and Deep Water Licensing Round of open blocks in November. The opening of the licensing round took place at the 25th Africa Oil Week held in Cape Town. The round will cover 34 oil and gas exploration blocks.

Pascal Houangni Ambouroue, Minister of Oil and Hydrocarbons, made the announcement during a special session at Africa Oil Week event on November 7. The announcement was followed by a technical and fiscal workshop that detailed the new petroleum code, the license round, and associated terms.

One of the highlights was the revelation would remove the 35% corporate tax on operators, as part of the revised petroleum law. The workshop also included further details of available blocks, the fiscal terms, timings and conditions of the 12th Gabon Licensing Round.

The Minister of Oil and Hydrocarbons advised on the dates and venues of the associated global license round Road Shows, supported by Spectrum.

Spectrum, in collaboration with the Direction Générale des Hydrocarbures (DGH) has undertaken a number of shallow water 3D seismic surveys across the open blocks available in the 12th License Round. This data provides the industry with state-of-the-art 3D broadband data. A variety of plays are targeted to allow a new generation of oil exploration in these prolific basins.

Seismic has been acquired in both the north and south of the country. The 11,500 sq km southern survey, now complete, is the definitive dataset to image the pre-salt and, for the first time, intra syn-rift plays can be targeted. In the North, acquisition of a 5,500 sq km 3D survey images pre and post-salt targets.

Savannah Submits Pre-feasibility Study on Niger Discoveries

Savannah Petroleum has submitted its pre-feasibility study (PFS) to Niger's Ministry of Energy and Petroleum. The PFS is in relation to its planned early production scheme on the R3 portion of the R3/R4 PSC in southeast Niger.

Savannah Niger, the company's subsidiary in the African country, undertook to prepare and submit the PFS within 90 days of the signature of its MoU with Niger. The MoU affirms the commitment of Savannah Niger and the government to realize a domestic-focused EPS using crude oil resources associated with its recent discoveries.

The PFS sets out Savannah Niger's plans for the Amdigh-1 well test, resource volumes expected to be developed as part of the EPS and associated potential production profiles, as per previous announcement and as reviewed by Savannah's Competent Person, CGG Robertson.

Libya to Relocate Swiss Refinery

Libya's state-run firm, NOC, wants to relocate its Collombey refinery into the southern portion of the country. With the events of the past seven or so years, it is often forgotten that the state-run firm held assets outside of the country, but NOC is the owner of the Collombey refinery in Switzerland.

According to a statement, NOC said that moving the refinery was within the framework of its ongoing efforts to address the southern fuel crisis, and the creation of projects to bring new employment opportunities and economic benefits to southern Libya.

Both NOC and Zalaf Oil & Gas Exploration and Production Co. have reviewed studies relating to the relocation of the refinery to southern Libya. The decision to relocate and proceed with the refinery project plan was recently taken during a meeting overseen by Khalifa Rajab, chairman of the Zalaf management committee, on November 11 in the presence of specialists from NOC's Oil Industries department, and the refinery working group team.

Source: Tamoil

Attendees stressed the importance of security, calling on the people of the south to support NOC and Zalaf in ensuring a stable security environment in the region given its importance for the successful implementation of this important project; one which will bring tremendous benefit to the southern population once completed.

The Collombey refinery is owned by Tamoil Switzerland Oil Company. Tamoil is the trading name of Oilinvest Group which is owned by NOC and the Libyan government.

NNPC and BP Enter Oil Swap Deal

In an effort to gain access to petrol Nigeria's state-run firm, NNPC, entered into a six-month crude-for-product deal with BP Oil International, the crude trading arm of BP.

NNPC said in a statement that this latest agreement would represent 20% of the state-run firm's petrol supply under the Direct Sale-Direct Purchase arrangement.

Head of NNPC, Maikanti Baru, said his firm was committed to product availability by inviting new and old players to play in the Nigerian oil sector, including supermajors.

NPPC also said later that it was working with Shell and ExxonMobil on a similar deal. "Unfortunately, Shell and ExxonMobil exited the downstream sector in Nigeria a couple of years ago but they are coming back for this particular arrangement, because it's an opportunity for them to get crude and sell their products to the refineries," NNPC's COO for upstream, Bello Rabiu, was cited by *Reuters* as saying.

The state-run firm is also wrapping up talks with consortiums including top traders, energy majors and oil services companies to revamp its long-neglected oil refineries in an effort to reduce its reliance on imported fuel.

Sonatrach Opts for Honeywell UOP Tech at Arzew

Honeywell UOP technologies will be used by Algerian state-run firm Sonatrach, to produce 200,000 metric tons per year of methyl tert-butyl ether (MTBE), a high-octane gasoline additive that reduces emissions in automobile exhaust.

Honeywell will provide technology licensing, design services, key equipment and state-of-the-art catalysts and adsorbents for the project at Sonatrach's refinery in Arzew. Included in the technology package is UOP's Butamer™ technology, which isomerizes normal butane into isobutane.

The package also includes a UOP C4Oleflex™ unit to dehydrogenate isobutane into isobutylene. C4 Oleflex features low energy consumption, low emissions and a fully recyclable, platinum-alumina-based catalyst system which minimizes environmental impact. This results in a lower cash cost of production, and higher return on investment than competing technologies. Honeywell UOP has been awarded 55 dehydrogenation projects since 2011.

The contract further includes a UOP Ethermax™ unit that converts isobutylene and methanol into a high-octane MTBE blending agent that contains no benzene or aromatics. The Ethermax technology delivers a high MTBE yield and is currently used in 44 units worldwide.

PetroSA Denies Report on its "Poor Quality Diesel"

South African state run firm PetroSA denied reports in the *Mail & Guardian* (M&G) alleging it was losing international buyers of its diesel due to its poor quality. The M&G report said that Shell South Africa was one of those firms that would cease buying diesel manufactured at PetroSA's Mossel Bay refinery.

In a statement the state-run firm said the news report, which cited highly placed individuals within PetroSA and CEF as its sources, alleged that the diesel that PetroSA produces from crude is off-specification and of such poor quality that Shell and the other major oil companies have decided to cut ties with PetroSA as customers for this product.

The company strongly rejected the allegations and reiterated its position, as stated in the company's response to the M&G, that it continues to enjoy good business relationships with its customers, and with Shell SA in particular.

"Shell SA is one of our valued customers and continues to buy the diesel that we produce in Mossel Bay," said PetroSA's acting Group CEO Kholly Zono. "PetroSA is committed to, and always strives to maintain its record of producing clean and high-quality products that we are known for."

"It is deeply worrying that the Mail & Guardian has published such damaging allegation sattributed to anonymous sources, without producing any concrete evidence to back up the sources' claims," he added.

Emerson Picks Up Alrar Job from Sonatrach

Emerson, in partnership with Fores Engineering, signed a $32 million contract with Sonatrach to modernize its gas processing plant in Alrar. As part of the contract, Emerson will combine its innovative technologies and operational certainty methodology to optimize Sonatrach's production operations and improve the reliability and security of the Alrar plant's processes.

Emerson's modernization program at the Alrar gas processing plant, in the southeast part of Algeria, is designed to help Sonatrach achieve Top Quartile performance – defined as operations and capital performance in the top 25% of peer companies.

In its role, Emerson will update control and safety systems, fire and gas systems, field instrumentation control and isolation valves, and other equipment to improve production efficiencies, equipment reliability and safety.

The project includes the engineering procurement, commissioning and testing of the new integrated control and safety systems, fire and gas systems, boosters and compressor controls, field instrumentation, liquid and gas metering skids, control and isolation valves, and other equipment for improved production efficiencies, equipment reliability and safety.

Mounir Taleb, vice president for measurement and analytical, Emerson Automation Solutions, Middle East and Africa said, "This project enables us to support Sonatrach to ensure its facility meets the latest standards for safe, reliable and efficient operations," adding "We are proud to provide Sonatrach the automation it requires to expand its gas processing operations in Alrar."

GE Power and GEL to Support Nigerian Refinery's Power Needs

GE Power Services signed a multi-year agreement (MYA) with GEL Utility Limited, a joint subsidiary of Engro Corporation of Pakistan and Genesis Power & Energy Solutions, to support the power generation requirements of NNPC's wholly owned subsidiary, Port Harcourt Refining Company, in Nigeria.

The 12-year MYA includes the provision of parts, spares, repairs and services over two major inspection cycles for three units of GE's TM2500 aeroderivative gas turbines earlier installed at the plant site in March 2015.

GE's Power Services offering will feature the expanded capabilities on GE's TM2500* fast power solution assets installed at the plant. GE's TM2500 aeroderivative gas turbines enable governments, utilities, and businesses around the world to fulfill their generation requirements within days. Thanks to their modular concept, fast installation features and quick production schedules, these units typically can be ready to enter into commercial operation approximately 30 days after an order is placed.

The state-owned refinery, which specializes in the refining of crude oil into petroleum products, will have an optimal supply of the power it needs to run its plant reliably and efficiently. GE's TM2500 fast power solution represents some of the most reliable distributed power units available. That means plant operators will not face frequent interruptions and instabilities due to technical problems related to faulty equipment or an unstable electricity grid. The units will also provide the ability to frequently and rapidly ramp up to meet load and demand fluctuations. With production capacity currently at approximately 210,000 bpd, the Port Harcourt refinery, which is also the country's largest operational refinery, needs a constant supply of power with no room for downtime to the facility and its operations.

Air Products and Sonatrach Sign Two New Agreements

Air Products and Sonatrach, Algeria's state-owned oil and gas company, signed two gas production and delivery agreements. Conducted through both companies' joint venture (JV), HELIOS, the deals have a combined value of $100 million.

Through the deal, Sonatrach will recover helium from two existing LNG facilities (GL1Z and GL3Z), and that helium will be delivered to HELIOS' existing liquid helium plant in Arzew. The HELIOS plant is an important part of Air Products' total global helium source portfolio, and the new feedstock will increase the amount of liquid helium produced by the JV plant.

Source: MiX Telematics

"The potential for helium production in Algeria is significant thanks to its large, established natural gas industry and LNG operations," said Walter Nelson, VP and GM–Global Helium at Air Products. "Connecting the HELIOS plant to Sonatrach's other LNG facilities in Arzew is a further illustration of how unlocking Algeria's helium potential can further diversify the helium supply chain and improve the reliability of supply for customers in Africa and Europe."

Another important component of the agreement is that Air Products will design and build, and HELIOS will own and operate, two new air separation plants in Algeria. One will be located in Hassi Messaoud and the second in Arzew. Once in operation, these plants will produce nitrogen, oxygen and argon, which will be supplied to the Algerian and Maghreb markets through Sonatrach's subsidiary, COGIZ.

These latest agreements are part of Sonatrach's 2030 Vision for growth, which includes a multi-billion-dollar investment program to expand Algeria's energy sector and infrastructure.

ESIA Nears Completion for Uganda/Tanzania Pipeline

The Environmental Social Impact Assessment report for the East Africa Crude Oil Pipeline is in the final stages and will be completed by next month. The pipeline will take Ugandan crude from the Lake Albert region to the Port of Tanga on the Tanzanian coast.

The completion and approval of the report will give the green light for Total to start on the implementation of the project. The pipeline is expected to cost around $3.5 billion and is planned to have the capacity to transport 216,000 bpd.

According to earlier negotiations, Uganda will pay Tanzania $12.20 for each barrel flowing through the pipeline.

It was said that the company would submit the report to the National Environment Management Council by December for approval.

Sanalla and BPMC Discuss Supply Challenges in Southern Libya

Mustafa Sanalla, chairman of Libya's NOC, is looking for a path forward to making sure southern Libya has access to fuel and cooking gas supplies. Toward this end, the chairman hosted an extended strategy meeting with the chairman and Board of Directors of Brega Petroleum Marketing Company (BPMC) to discuss key challenges.

The parties agreed that the low access was principally caused by a lack of security in the region, calling for enhanced cooperation between security authorities, and for citizens of the south to renounce and demand justice against the criminal gangs that threaten truck drivers – a major cause of suffering for those in the south.

BPMC's strategic plans covered the development of permitted investment projects, local market fuel supply, management of bottlenecks, and improving the distribution and control of products to gas stations – thereby increasing accessibility for citizens. Chairman of BPMC's management committee, Imad Benkoura, also presented the company's strategy for reducing smuggling in the country. Attendees were additionally briefed on the extent of the damage caused by hostilities near the Tripoli depot facilities in September of this year.

The NOC chairman praised the efforts of BPMC and its staff across the country, encouraging them to persevere in spite of ongoing national challenges.

COTCO Could Double Pipeline Flows by 2022

The managing director of the Cameroon Oil Transportation Company (COTCO), Johnny Malec, said the volumes of crude transported through the pipeline could double by 2022. An increase in crude being shipped through the pipeline would be a boon for Cameroon's economy.

The increase in production would come from new operators that have arrived in Chad over the past few years. Since the pipeline's inception, the Chad-Cameroon pipeline has shipped 680 million barrels of crude.

There is also the chance that crude from Niger could be shipped through the pipeline. There has been talk of a pipeline being constructed from the oil fields of Niger to the pipeline in Chad, shipping it on through the Chad-Cameroon pipeline to the coast of Cameroon.

BP Slates $1 Billion for South Africa Downstream

BP Southern Africa (BPSA) will invest $1-billion in South Africa over the next five years with more than a quarter of that set aside to upgrade the SAPREF refinery to produce lower sulfur diesel, its chief executive Priscillah Mabelane said, according to a Reuters report.

The refinery, which produces 180,000 bpd, is a 50/50 venture between Shell and BPSA, a subsidiary of UK-based major BP.

BP plans to invest $252-million to $288-million in the refinery upgrade, Mabelane said. The upgrade is to ensure that the refinery can meet the new specifications in terms of low sulfur and Marpol regulations. Mabelane added that about 40% of the total $1-billion investment would go toward retail activities.

Three Nigerian Modular Refineries on Pace

Nigeria's Minister of State for Petroleum Resources, Ibe Kachikwu, said there are strong indications that three out of the 40 planned modular refineries would come on stream by the end of 2019.

"Out of the 40 licenses issued, only 10 have shown progress by submitting their programs and putting something on the ground. By the end of 2019, we are assured that three private modular refineries would come on stream," he said.

By Catarina Távora
Miranda & Associados

EQUATORIAL GUINEA

Time to Prepare for a New Licensing Round

Last September, the Minister of Mines and Hydrocarbons of Equatorial Guinea, Gabriel Mbaga Obiang Lima, announced that the country will be launching a new bidding round in 2019 for oil and gas exploration in both onshore and ultra-deepwater areas. The last licensing round was opened in June 2016 and closed in mid-2017. Out of a total of 23 companies expressing interest, 12 submitted official bids and six were announced as winners along with ExxonMobil, who had recently signed a contract through direct negotiations. Other direct negotiations followed as different oil companies, including majors, have been showing interest in the country's hydrocarbons potential.

The key legislation that governs exploration, development and production of hydrocarbons in Equatorial Guinea is the Hydrocarbons Law which came into force in November 2006 and was complemented in 2013 by Regulations on Petroleum Operations and in 2014 by Regulations on National Content. No major regulatory change is expected before this new licensing round.

Although the Hydrocarbons Law would allow other contract options, petroleum contracts have always taken the form of production sharing contracts (PSCs) and are negotiated on the basis of a model contract developed by the Ministry responsible for petroleum operations since 2006.

The Minister has full authority to negotiate, modify and sign PSCs, but contracts only become effective after they are ratified by the Head of State. Usually, the ratification process takes at least one month and contracts become effective on the date the Contractor is notified by the Ministry of the ratification. Yet, the Ministry usually sets up teams including representatives of other governmental departments, in particular the Ministry of Finance, to negotiate contracts so that all relevant aspects can be reviewed and considered, which facilitates the ratification process.

Under the Hydrocarbons Law, petroleum operations are divided into two different phases: the exploration period, which includes an exploration phase and appraisal; and the production period, which encompasses both the development and the production phases. In turn, the exploration period is split into two sub-periods each with associated minimum work and area relinquishment obligations. The standard duration of the initial exploration period shall be between four and five years and a maximum of two extension periods of one year each are allowed. However, the Hydrocarbons Law enables the Ministry responsible for petroleum operations to change the duration of such periods for each contract. Also, the typical duration of the production phase has been of 25 years for each field after the date of approval of the field's development and production plan, plus an extension, but the Ministry has the ability to agree on a different duration.

The minimum work to be performed during each exploration sub-period, which typically includes the acquisition of seismic data and well drilling, and the size of areas to be relinquished are also agreed in each PSC. A key factor for block award decisions is the minimum work investment commitments that bidders offer.

> "The State is also entitled to royalties in the amount set forth in each PSC and royalty rates proposed by bidders are also very important. Contractors are to propose increasing levels of royalty based on daily production rates with a minimum of 13%."

In addition to taxes payable under the General Tax Law, including

Corporate Income Tax on the annual net profits at the rate of 35%, with a minimum of 800,000 XAF (approximately $1,409 USD) per year, regardless of whether or not there are any taxable profits, contractors have to pay annual surface rentals and bonuses which are set forth in PSCs and agreed with the Ministry. The 2006 Hydrocarbons Law also makes reference to a windfall profit tax. This tax, however, is not set forth in the tax legislation currently in force in Equatorial Guinea and there is no indication that it will be introduced in the near future.

The State is also entitled to royalties in the amount set forth in each PSC and royalty rates proposed by bidders are also very important. Contractors are to propose increasing levels of royalty based on daily production rates with a minimum of 13%. Unless the Ministry decides otherwise, royalties are to be paid at least on a monthly basis, in cash and at market prices to be computed in accordance with the terms of each PSC to be proposed by bidders.

In addition, under the Hydrocarbons Law the State may elect to have, either directly or through a National Company, a minimum carried interest of 20% in each PSC. The proposal of any additional interest to GEPetrol – the National Oil Company – and the percentage of GEPetrol's cost recovery oil to be allocated each year to the Contractor parties that have carried GEPetrol during exploration are factors that may render a bid more attractive for the State.

Finally, PSCs set forth minimum amounts to be spent every year by Contractors during both the exploration and production periods for national content purposes, including on training and welfare projects designed to benefit local communities, such as the construction of schools and hospitals. This type of investments and the annual amounts offered can also be used to make bids more attractive.

The Ministry of Mines and Hydrocarbons is currently in negotiations for the extension of some PSCs and apparently plans to have these negotiations concluded by the end of the year. Therefore, the official launch of the licensing round is expected for January 2019. This gives newcomers some months to prepare and consider how to address each of the above issues in their bids.

About the Author
Catarina Távora is a Partner and Global Head of the Energy and Natural Resources Practice at Miranda & Associados. Catarina frequently advises oil & gas companies in setting up and carrying out their operations in Africa. Catarina may be contacted at Catarina.Tavora@mirandalawfirm.com.

Halliburton Releases First Fluid Efficient Dissolvable Frac Plug

Halliburton Company has released the Illusion® Spire, the first fluid efficient dissolvable frac plug. This offering expands on the capabilities of current dissolvable plugs, but with a larger internal diameter and less mass for greater efficiency.

In the unconventional market, the time to bring a well on production is critical. Traditional plug designs can result in suboptimal plug conveyance and excessive fluid volumes. Halliburton Completion Tools designed the Illusion Spire technology with a water saving element so that operators can pump faster, resulting in reduced completion time. The reduced plug size also drives quicker and more consistent dissolution time.

"Our goal was to develop the industry's most advanced frac plug that delivers increased efficiency to help operators reduce rig time and save costs,"

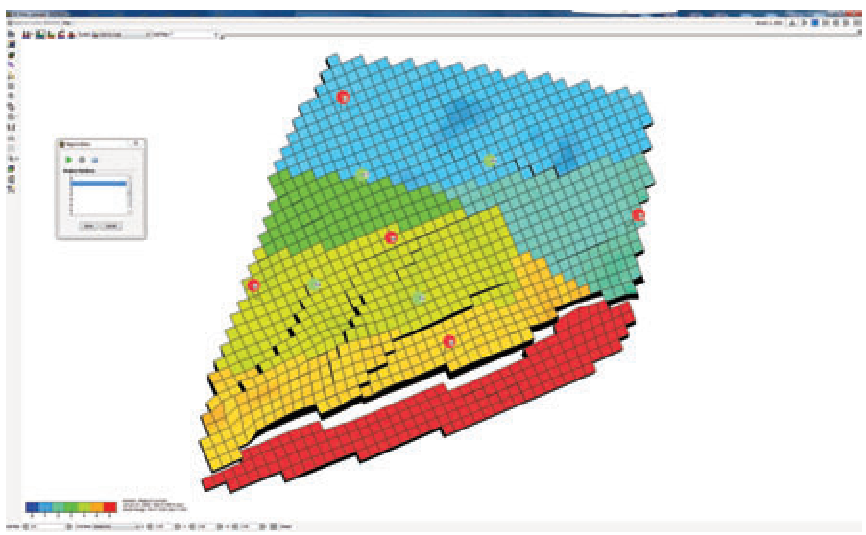
Source: Halliburton

said Mark Dawson, vice president of Completion Tools. "Illusion Spire is the only efficient dissolvable plug that decreases water costs and substantially increases flowback to help maximize operators' asset value."

During multiple field trials conducted in North American basins, Illusion Spire demonstrated fluid and time efficiency improvements that are unprecedented compared to other plugs on the market. In a typical wellbore, this can save thousands of barrels of fluid and reduce overall pump time.

New Release of Tempest 8.3 takes Automation a Step Further

Emerson has announced the release of Roxar Tempest™ 8.3, its integrated reservoir engineering suite that offers tools for advanced reservoir management and flow simulation. The latest release takes automation a step further and focuses on increasing user productivity, for a superior understanding of the reservoir and its potential for return on investment. The new product suite strengthens Emerson's end-to-end Exploration & Production (E&P) software portfolio, comprising Paradigm and Roxar software solutions, aimed at helping operators efficiently exploit both new and established reservoirs.



Source: Emerson

Tempest 8.3 provides increased compatibility with industry-standard reservoir simulators, enabling users to run third-party simulation datasets, such as ECLIPSE* models, with minimal changes. Additionally, algorithmic consistency in the product suite ensures that the volumes and reserves estimates are preserved when using third-party simulation decks with MORE. This compatibility enables the easy embedding of simulation workflows and models within Big Loop™, which links static uncertainties and flow parameters to ensure that geologic and geophysical constraints are honored when matching production. Further gains in productivity are achieved by easy and interactive creation of simulator regions and the streamlined analysis and export of well-to-well flows.

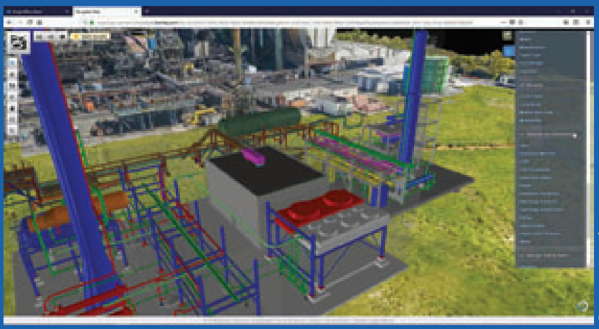
The ENABLE module within Tempest 8.3 also comes with a host of user-driven improvements serving Big Loop, including the ability to select and relaunch a specific simulation, to test out additional settings or investigate the causes that previously led a run to stop.

Roxar Tempest runs on Windows and Linux, and operates alongside Emerson's reservoir characterization and modeling solution, Roxar RMS. Tempest is an integrated software suite that provides a wide range of reservoir engineering features and is used in hundreds of installations worldwide. All modules can be deployed together or separately within third-party simulation workflows. To learn more about Tempest 8.3, visit *www.Emerson.com/Tempest8-3*.

PlantSight Digital Twin Cloud Services Debuts

Siemens and Bentley Systems announced the introduction of *PlantSight*, resulting from development together based on their highly complementary software portfolios. *PlantSight* is a digital solution to benefit customers through more efficient plant operations. *PlantSight* enables as-operated and up-to-date digital twins which synchronize with both physical reality and engineering data, creating a holistic digital context for consistently understood digital components across disparate data sources, for any operating plant. Plant operators benefit from high trustworthiness and quality of information for continuous operational readiness and more reliability.

Every real-world operating plant is characterized by cumulative evolution, both to its brownfield physical condition and to the varied types and formats of theoretically corresponding engineering data. Accordingly, as-operated digital twins must reliably synchronize reflections of both the physical reality and its virtual engineering representations, comprehensively and accurately. Moreover, further frequent changes are inevitable. With *PlantSight*, every process plant owner-operator can realize the benefits of as-operated digital twins – without disruption to their existing physical or virtual environment.



Source: Bentley

For process industries, characterized by ongoing capital projects, the effectiveness of digital twins depends upon the integrity and accessibility of as-operated information presented and continuously updated in trusted 2D schematic and 3D model formats. *PlantSight* provides all stakeholders with cloud/web-enabled visibility and access into existing data and tool interfaces, assuring that changes are timely and accurately captured and managed.

With *PlantSight* as-operated digital twin cloud services, operational and project-related engineering data is aligned seamlessly. All disciplines and stakeholders have immediate access to consistent representations. Especially for brownfield installations, the time and effort to federate and complete asset information will be significantly reduced, with plant documentation kept up to date, and its quality accordingly improved.

New Premium Oil Filtration System for Power End Lubrication

The leading cause of premature power end failure is contamination of the lubrication oil. To address this issue Caterpillar has released a premium Oil Filtration system for the Power End Lubrication as an installed standard attachment.

The Cat® Well Stimulation Pump Power End Lube Oil Filtration allows oil to be cleaned with the specifications that Caterpillar recommends. By integrating industry leading filters from the TH55 transmission into the power end filtration system, Caterpillar provides world class filtration to power ends, as well as parts commonality with the transmission of choice for well stimulation customers.

Source: Caterpillar

The oil filtration system is available on every Power End Only, Complete Pump and Configurable Pump horsepower.

One benefit of the system is simplified maintenance, as it is capable of being mounted on the power end itself, allowing for rapid filter changes. Meticulously designed, the filtration system provides its greatest benefit of limiting contamination downstream. Now, there is less chance of debris being introduced from intermediate components. Another convenience of the system is the ability to use the same tools for transmission filter changes.

Two additional features of the system include an integrated bypass sensor and sampling ports both upstream and downstream of the filter to allow for a consistent oil sampling process. In conjunction with a Scheduled Oil Sampling (SOS) program, this allows extended oil change intervals while ensuring satisfactory oil cleanliness. The oil filtration system is fully integrated with the Pump Electronic Monitoring System (PEMS), which provides oil pressure, oil temperature, and filter differential pressure data via J1939 standard.

Available now, the new system is compatible with and recommended for retrofit of already shipped Cat power ends.

By Aquaterra Energy

SMALL DIFFERENCES AND BIG CHANGES

From Potential to Profit in West Africa

It rarely pays to generalize in the global oil and gas industry, where profit can be found in even the smallest differences of geology on one hand, and infrastructure on the other. Nowhere is this more true than in West Africa, where mature producing nations like Nigeria or Angola resist easy comparison with each other, never mind the neighboring countries whose production capacity and supporting industrial ecosystem is in a much earlier stage of development.

Even the idea of countries being on a spectrum from frontier nation to mature market is slightly misleading. Nigeria and Angola are not alone in physically producing oil and gas for decades, but a patchy history of investment and political interventions have created the diverse picture we see today. Sporadic investments and decade-long delays in following up on exploratory activities have decelerated the acquisition of skills and capabilities that were needed to maintain momentum.

There is also no such thing as a West African rulebook at present. International codes and specifications obviously apply, but unlike some other areas of the world, for example the North Sea where pan-European law applies, each African country has different specific requirements. That could well change in the future as the various Regional Economic Communities, and the overarching African Economic Community push for greater harmonization on trade and other economic concerns. But the current picture remains fragmented and far from homogeneous.

What does unite the various markets in West Africa are the opportunities that are still available. Mature countries are extending the life of existing offshore platforms and exploiting more difficult to access sites; for frontier countries, it's the race to achieve first oil from extensive shallow-water reserves. For investors, operators, financiers, engineers and manufacturers and for the countries themselves, the potential is absolutely there, provided these differences are understood, and a number of challenges overcome.

Perhaps the greatest hurdle for the region is that the necessary logistics and infrastructure are either entirely absent or for many, not yet sufficiently mature to support oil production in a safe, efficient and sustainable way.

As the region's most developed market, Nigeria is home to many large yards that between them can produce any fabrication required.

Source: Aquaterra Energy

Sea Swift platform 1

Of equal importance, the country has a well-established and talented core of people with the skills and experience in analysis, engineering and HSE to sustain a wide-reaching and multi-faceted industry. Emerging countries struggle in both areas. Even Angola, the second biggest player in West African oil, still relies on domestic fabrication facilities that have not yet reached world-class capabilities.

This is where the law of unintended consequences makes an appearance. Each producing country in West Africa may be at a different stage of maturity, but they all want to develop, maximize in-county operations and increase indigenous capabilities.

However, 'rules of origin' policies that are intended to protect developing local industry by specifying local content, can actively work against these goals. The financial incentives of the various stakeholders are often misaligned, and policy that is supposed to encourage a thriving local industry inadvertently stifles it, holding back further development in fabrication, logistics and operations.

> "Mature countries are extending the life of existing offshore platforms and exploiting more difficult to access sites; for frontier countries, it's the race to achieve first oil from extensive shallow-water reserves."

Even in Nigeria, with its advanced fabrication yards, consumables that are used for manufacture of platforms, drilling or production-based activities often must be imported. So, while the country's world-class engineers are

Source: Aquaterra Energy

Sea Swift platform 2

assembling the component parts of a sophisticated offshore platform, all the steel they use is shipped in, as is the topside equipment, the valves, and the pipes.

In places like Cabinda or Cameroon, the yards don't yet have the capability to handle extremely large fabrication, and some of the critical quayside facilities that are needed to do large wellhead jackets, for example, may not be available. In truly frontier countries, this can mean that local content will only amount to a small amount of fabricating or machining – which does little to up skill local engineers, enhance local employment opportunities or build a sustainable, domestic industry.

> In contrast to a large conventional jacket design, a more modular offshore platform approach suits the existing and emerging capabilities typically found in frontier countries or indeed the smaller yards in more developed areas.

Breaking this self-propagating cycle while respecting national independence is no easy task. However, one of the answers lies in the very design and conception of offshore platforms so that they are less dependent on larger fabrication capability or expensive transportation, and therefore suited to smaller or less developed fabrication capabilities, as well as the bigger and more developed ones.

In contrast to a large conventional jacket design, a more modular offshore platform approach suits the existing and emerging capabilities typically found in frontier countries or indeed the smaller yards in more developed areas. The manufacture can be split up between a number of smaller yards, for example, or laid out in such a way that it fits into the smaller space that is typically available.

Alternatively, domestic yards can build certain parts of the platform, such as the subsea structure, while the topside equipment that requires more complex fabrication can be produced elsewhere. As a solution it allows for a significant degree of local content, while also building local capability over time.

Modular design allows platform developers to provide a more bespoke solution that takes into account not just the fabrication facilities, but also the availability of external vessels and cranes, port size and berthing capacity, transportation and installation, and the myriad of other small differences that make each market unique.

It also reduces the burden placed on many of these factors. For example, a platform sub-structure weighs something in the region of 220-250 tons. Lifting that amount of steel structure is by no means easy, but it is a lot easier than trying to find a crane to lift the 800 tons of a typical jacket for that water depth in a country with a limited capability.

The advantages ripple out from there including costs. Mobilizing that heavy-lift crane to the West African coast and back again can cost many millions of dollars that could instead be put towards the cost of a modular platform. As such, a site-specific solution designed around available resources will reduce the overall project cost. That means it is more likely to get the green light, which in turn creates a route to first oil that smaller independent operators can achieve.

To date, our Sea Swift platform has been deployed four times off the coast of Africa, with a contract in place to deliver two more platforms offshore Nigeria, both to reach first oil in 2019.

There are huge possibilities throughout West Africa, for operators and for producers, but also for the countries themselves and their local populations. But turning that potential into production and profit requires smart thinking and an approach that has individuality, specificity and expertise at its heart. This isn't the narcissism of small differences. It's the proven path to success.

By Gillian King and Phil Stone
Tendeka

The Wonder of Wireless for Well Development

Following the abrupt decline in production caused by plummeting oil and gas prices, recent reports suggest a revival for Africa's oil and gas industry as drillers begin to return to the region. According to analysts Wood Mackenzie, higher crude prices, stronger balance sheets and growing demand for natural gas are enticing supermajors back for business.

Another report expects nearly twice the number of offshore exploration wells to be drilled this year – up from 17 to 30. With at least 41 billion barrels of oil and 319 trillion cubic feet of natural gas yet to be discovered in sub-Saharan Africa, the research by the US Geological Survey claims the prize is huge. Such prospects are comparable to more than five years of the USA's oil consumption and 12 years of gas.

To safely and efficiently maximize production, support and investment in a digital oilfield market is expected to grow by more than a quarter (28%) within four years – from $21.14 billion last year to $27.10 billion in 2022. The increasing focus on optimization through digitalization, particularly in mature fields, is being led by oil and gas markets in Africa, alongside Asia Pacific and the Middle East.

Digital completions

The challenges associated with achieving rapid uptake and acceptance of new technology in the sector are well documented. The industry's inherent risk-averse nature, and hence its 'race for second' attitude may hinder its impact on innovation.

However, there is no doubt the impact of digital oilfield integration and automation on the industry is substantial, allowing more efficient operations, optimized production planning and ultimately greater recovery.

In the completions sector, wireless and automated technologies have been successfully applied in the wellbore for many years enabling effective directional drilling, surface read-outs during drill stem testing, and more efficient operations. The latest technology is targeting the production phase, providing monitoring and intelligent control to manage inflow downhole with connectivity to the engineers' desktop.

All images are courtesy of Tendeka

Figure 1: Tendeka's PulseEight device

Tendeka, the independent global completions service company, is expanding its footprint in Africa's oil and gas exploration and production sector, by implementing new cutting-edge technologies to develop the continent's energy sector.

Dialling downhole via smart phone

Increasing wellbore complexity and the desire to drill longer wells with maximized reservoir contact means that traditional methods for monitoring and control are no longer adequate. The main advancement has been moving from costly and complex control line bundles for communication and actuation, to smart, wireless systems which negate the need for additional hardware, manpower and rig-time.

Tendeka's PulseEight wireless intelligent completion technology (*Figure 1*) uses pressure pulse telemetry to communicate bi-directionally between the wellhead and downhole. Sending pressure, temperature and status data to surface and instructions down to the tools, it provides a new way of controlling flow and optimizing production. It uses energy from the production flow to transmit the data which can be read on the surface pressure gauge without the need for additional surface kit or signal boosters (*Figures 2 and 3*). The ability to communicate down the well to 'talk' to the tools to open/close/choke was proven in field trials in late 2017 as was the ability to access the data, via the cloud,

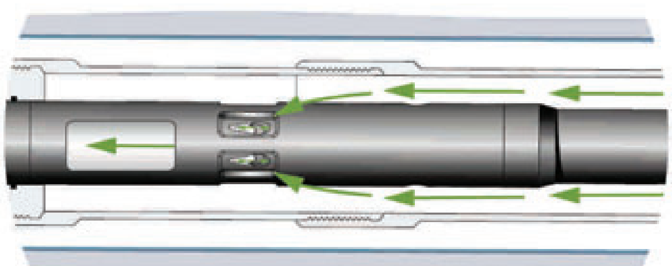


Figure 2: Flow from the reservoir enters ports in the tool and flows to surface

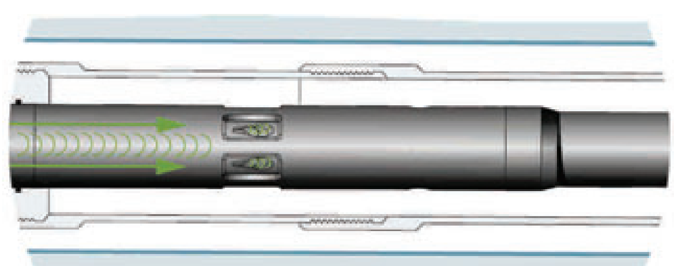


Figure 3: Commands are generated on surface using the wellhead choke and sent to the downhole device.

from anywhere in the world: operators actually used their own smart phones to watch the pressure pulses occurring.

The ability to retrofit PulseEight devices into existing wells has created many new applications for the technology in addition to a pressure/temperature gauge and interval control valve (ICV). For example, formation integrity, multi-lateral wells, gas-lift optimization, gas hydrate prevention and water/gas shut-off to name a few.

Safety first

One of the more valuable propositions is to use the PulseEight tool as a safety device. This is currently under field trial in the UK. In wells where safety valves have experienced problems with the control line, ambient valves or storm chokes are typically run to act as a secondary barrier mechanism. Inherent issues with the reliability of these devices and loss of production associated with them have meant that operators are looking for a safe and effective alternative.

The system has intelligence built into the device so it can detect changes in the downhole conditions and react autonomously. For example, in the event of an emergency shutdown or loss of well control, it will detect a rapid increase or decrease in pressure and close.

Through the mitigation of hazards and the number of personnel exposed to them, deployment of the technology also has the potential to improve operational safety, compared to normal intelligent well system operations.

Regular intelligent completion functionality and communication tends to be conveyed by TEC lines, hydraulic lines or, in some cases, both. Typically, these lines are deployed as the completion is run-in-hole with the use of air-driven spooler units, which, depending on the control line or flatpack, may be cumbersome and take up precious deck space.

Although spoolers would perhaps be adequately guarded, rotating equipment poses several hazards, which while mitigated, are inherent by design. If their movement is initiated remotely as is the case when the completion is lowered, it may be prudent to have the spooler manned throughout. This could mean another individual exposed to a hazardous environment, that may not be necessary during PulseEight operations.

Ultimately, fewer people on board the installation or asset means less people exposed to hazards and, in the case of retro-fit solutions, bed space may be at a premium on mature field assets where no MODU is alongside and where many PulseEight applications may be found.

As the technology can be run on wireline, this reduces operational time compared to running technologies on tubulars. Tubing retrievable (TR) intelligent well solutions can require large pulling capacity to replace as, once a TR system fails, there may not be much the well owner can do to recover functionality other than to recover the completion and workover the well. PulseEight offers a solution that can be run, communicated with bi-directional and configured in situ. Unlike TR options, the tool can be recovered and replaced as required.

Control lines themselves are not without potential to cause harm. Both electrical and hydraulic systems pose hazards to operators, whether that takes the form of electrocution or unplanned escape of pressurized control line fluid, some of which are attributed to causing contact dermatitis. Also, control lines could be susceptible to failure and dropping to deck from sheaves, endangering those in the firing line. This arrangement may present further hazards during adverse weather conditions and may even become inoperable in extreme instances.

Cross coupling protectors or clamps are the industry standard for affixing control lines to the conduit tubing. Generally installed with the use of pneumatic ratchet guns, these would usually number in the hundreds, with the quantity increasing with well depth.

Repetitive lifting and positioning clamps, which typically weigh a few kilograms, subsequently presents manual handling concerns, alongside the conventional pinch points and hazards associated with using hand tools.

Figure 4: Wireless intelligent well technology can extend the operating envelope for the advanced completion

The use of Pulse Eight ultimately mitigates hazard exposure and reduces OPEX through less deployment time, manpower and possible accidents. The diversity of reservoirs and applications across the sub-Saharan countries are hugely interesting and advanced completion technologies can play a major role in maximizing recovery for operators.

African ambitions

The first installation of the PulseEight in sub-Saharan Africa is planned for later in 2018 (*Figure 4*) and is part of the company's long-term commitment to the region. Tendeka recently appointed Phil Stone as Business Development Manager for sub-Saharan Africa, who is working to establish key technology partners and local agents to bring the company's technologies to market. Phil has held several field and shore-based positions in sub-Saharan Africa including Operations Manager for Completion & Well Construction in Nigeria, Business Unit Leader for both Reservoir Monitoring and Upper Completions, based in South Africa, and Regional Applications Engineer, based in Aberdeen.

As a sign of its growth and influence in the region, Tendeka was recently awarded its first contract with a sub-Saharan operator to supply autonomous inflow control devices (AICD). The multi-million-dollar contract, which commenced earlier this year, will provide FloSure Elite sand screens alongside its FloSure autonomous inflow control devices (AICDs) and zonal isolation products for two major developments in the region.

The FloSure AICD device works on the principle of Bernoulli's equation and differentiates between different fluids within the reservoir based on their viscosity, preferentially choking those travelling through the device at higher velocity (lower viscosity). The AICD has now been installed in more than 140 wells and has shown significant increases (up to 50%) in oil production by delaying the early breakthrough of unwanted gas and/or water.

The company is also about to deploy its first commercial installation of Cascade[3] in the region by the end of the year to address the challenge of sandface injection flow for water injector wells.

This new well screen, flow control completion system utilises intrinsic check-valves to prevent any backflow or crossflow during shut-ins. Depending on well conditions, it also limits the damaging effects of water hammer. Its commercialization follows a three-year R&D program and field trial with a major operator in the Gulf of Mexico to improve performance on water injections wells which had suffered severe loss of injectivity within a short period of completion.

Tendeka is continually developing new technology offerings to enhance reservoir recovery, with sub-surface engineering and innovation teams working to bring reliable, cost-effective alternatives to meet operator challenges. With increased focus on the region going forward, Tendeka aims to support Africa's drive to be recognized as a major oil and gas hub again.

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By Muktadir Ur Rahman
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Supermajors Cost Index
Has Cost Efficiency Peaked?

A combination of rising oil prices, stronger balance sheets and continued significant cost deflation has created a 'sweet spot' for oil and gas companies to start investing in new projects.

Overview of recent developments

The oil and gas industry has experienced some dramatic changes over the last couple of years. Prices collapsed to around $26/bbl in early 2016 (*see chart 1*) as the market became increasingly gloomy about persistent excess supply in the global oil markets and OPEC's ability to reach an agreement among its members to address this worldwide glut.

But bearish sentiments gave way to optimism as robust global economic growth led to higher-than-initially-anticipated demand for oil. This, together with the historic OPEC and non-OPEC alliance to address the oil inventory overhang, resulted in a strong price recovery. As a result, prices more than doubled from their nadir in the first quarter to over $52/bbl by the end of Q4 2016.

Source: U.S. Energy Information Administration (EIA), Apex

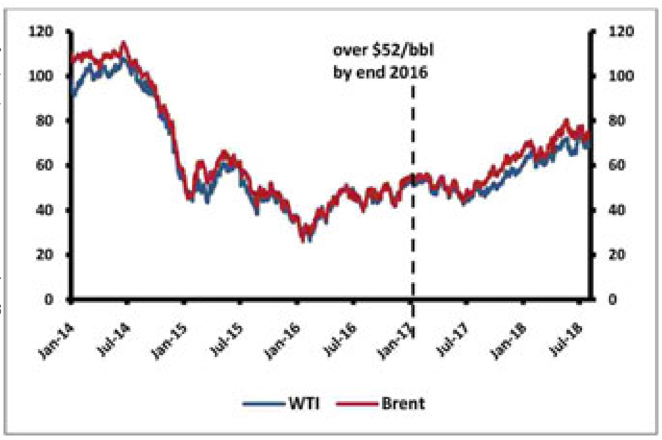


Chart 1: Crude Oil Prices since January 2014 (US $ per Bbl)

Other than occasional fluctuations, prices continued to move upwards throughout 2017 and for the most part in 2018 as inventories fell sharply. By the end of April 2018, OECD commercial stocks dropped from 292 million barrels above the five-year average a year ago to 27 million barrels below the five-year average.

Strong, synchronized growth across the major economies, and record-high compliance with the production cuts agreed by OPEC and non-OPEC members, were mainly responsible for this reduction in stocks of approximately 319 million barrels. Geopolitical factors, such as supply outages in Venezuela, also contributed to this earlier-than-expected decline in the OECD commercial inventory level.

Higher oil prices also helped oil and gas operators to rebuild their financial health. The combination of rising oil prices, stronger balance sheets and an industry still experiencing significant cost deflation created a 'sweet spot' in which oil executives felt confident enough to start investing in new projects. As a result, a number of flagship projects received the go-ahead in 2017. For example, Shell decided to proceed with its Kaikias development in the Gulf of Mexico, which was its first such investment in more than a year and half, while ExxonMobil gave the green light to phase 1 of its Liza field development in offshore Guyana.

As optimism gradually returned to the market and capital spending picked up after years of deep cuts, many industry players and observers became concerned about the sustainability of the cost reductions achieved during the downturn. Citing recent cost inflation in the US shale region as an example, some argued that the industry was moving back to a high cost environment as a wave of new projects reached Final Investment Decision (FID) in 2017.

Given that the number of new projects, including large-scale LNG projects, reaching FID in the coming years is expected to remain high by recent historical standards it is instructive to analyze the industry's latest performance in developing its reserves. We have therefore updated our proprietary Supermajors Cost Index to determine how the industry has performed over recent years, and also investigated the performance of the industry's 'trendsetters', the seven supermajors, in this context.

Supermajors Cost Index: a historical context

In the early 2000s, oil prices entered a 'super cycle' phase alongside other commodities (*see chart 2*). Robust global economic growth, surging demand for commodities from emerging markets and developing economies (EMDEs), such as China, and supply deficit caused by underinvestment in various commodity markets during the previous decade were the main drivers behind this extended and sharp rise in commodity prices.

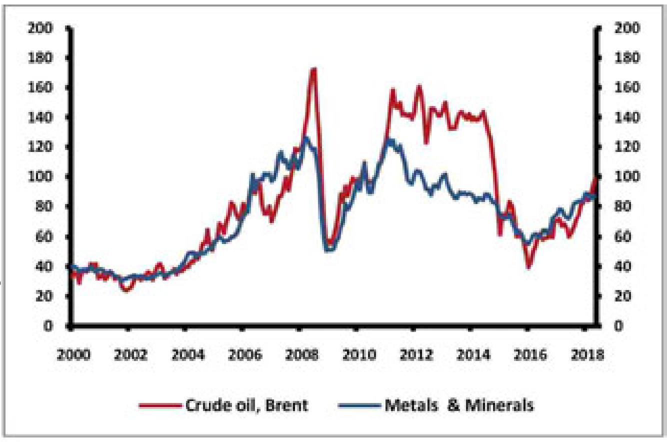


Chart 2: Nominal Commodity price indices (Sept. 2010 = 100)

In the case of oil, this strong demand coincided with a period in which 'peak oil supply' dominated industry thinking. As a result, the industry expected oil prices to move considerably higher than the previous decade average of $20/bbl. This expectation changed the strategic priorities of oil and gas companies markedly. After more than a decade of retrenchment, the industry moved into a growth phase, and resource and reserves development became the primary focus of oil and gas operators

.

This shift in volume growth encouraged companies to develop shale, deep water, ultra-deep water, and heavy oil resources in more technically challenging and harsher environments. The greater technical risk profile of these resources meant that the costs of developing these assets were higher than for conventional onshore or shallow water developments. Partly because of the development of these inherently riskier resources, global oil and gas capital investment increased almost five-fold, from $160 billion in 2000 to $780 billion in 2014 (in 2015 US $).

Other factors also contributed to the staggering growth in upstream capital investment in this period. Excessive focus on 'volume growth' in many cases resulted in poor planning and flawed project execution. As a result, the industry failed to deal effectively with the myriad of technical and non-technical risks associated with these new sources of supply. Cost overruns and delays became the norm. Indeed, a study conducted by the Oil and Gas Authority in the UK found that between 2011 and 2016, on average, projects in the UK Continental Shelf (UKCS) were costing 35% more than estimates in the FDP (Field Development Plan) and were delivered 10 months late.

Sustained capex growth since 2000 also ushered in a period of significant industry-wide cost escalation. Prolonged ramp-up of upstream capital investment created unprecedented pressure on the supply chain. Therefore, cost of materials (e.g. steel, cement etc.), equipment (e.g. rig rates) and labor increased significantly over the same period. The situation was made worse by the rent-seeking behavior of industry participants, as material suppliers and oil services companies tried to grab their share of the higher oil price dividend, alongside national governments and regulators.

This mix of higher cost resources, industry-wide cost escalation, and cost overruns and delays meant that the productivity of the vast sums of capital employed suffered significantly. As a result, our Supermajors Cost Index almost doubled between 2011 and 2014 (*see chart 3*). We estimate that development cost per BOE (barrels of oil equivalent) for the supermajors as a group went up from just over $11 to almost $22 during this period.

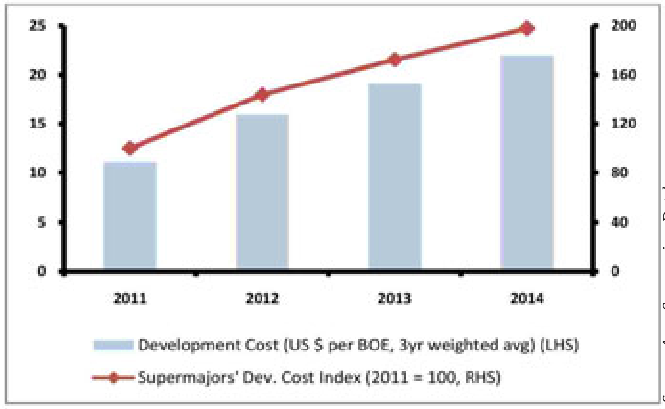


Chart 3: Supermajors Cost Index – evolution of development costs (2011 – 2014)

Note:Supermajors group consists of Shell, BP, Total, ENI,Chevron, ExxonMobil and ConocoPhillips.

Supermajors Cost Index: post 2014

Global growth remained sluggish between 2014 and 2016 due to subdued economic activity in the advanced economies as well as in the EMDE regions. This period of weak global growth took place against the backdrop of weakening long-term demand for fossil fuel brought on by a continued increase in energy efficiency and energy productivity, a growth in renewables, and the rise of electric vehicles. While oil demand prospects remained weak, supply continued to increase throughout this period, led by US shale production. In 2014, growth in US shale oil production alone outstripped the rise in global oil demand. The resulting oversupply triggered an almost 18-month long decline in oil prices.

Prior to its collapse in mid-2014, price growth had slowed significantly in response to weak projections of long-term oil demand. This, together with the staggering rise in the cost of developing assets, brought cost reduction back into the spotlight. As a result, by the end of 2013, several projects were delayed or canceled and many companies had cut their capital investment budget for 2014. For example, in 2013, rising costs forced Equinor (previously Statoil) to defer its development plan for the Johan Castberg field, while Shell cut its 2014 upstream investment budget by 20% to improve its financial performance.

At the same time, a number of companies, such as Chevron and Total, were coming out of a major capital investment cycle. The combination of project cancellations and a slowdown in upstream investment eased the pressure on the supply chain which had previously caused service and supply costs to escalate. As a result, service sector cost started to soften as early as 2014.

This trend of project cancellation and cuts in investment accelerated sharply as prices more than halved over the next couple of years. As the industry's attention shifted back firmly to value instead of volume, companies decided to high-grade their portfolios and focus investment activities on their most productive low-cost basins. In addition, operators took a number of steps to reduce the costs of developing assets, as many projects were not commercially viable in this 'lower-for-longer' oil price environment.

Prior to the price collapse, developing large new flagship projects at frontier basins requiring vast upfront capital was the norm for the big players. After prices collapsed, the industry's attention shifted to developing projects with smaller footprints, less capital intensity and shorter payback. Consequently, there was (and still is) a strong focus on developing incremental brownfield projects, developing projects with smaller facilities and fewer wells, and making use of existing infrastructure to reduce upfront capital requirement. Instead of customizations and unique solutions, simplified processes and standardization became the preferred options, enabling companies to achieve manufacturing-like efficiencies through repeated utilization of the same processes and technology. Instead of 'future-proofing' new developments, companies delayed the design of future development phases to exploit the technology available at the time and take account of prevailing market conditions in their investment decisions. These steps generated significant cost savings for the industry. In addition, costs went down further as technological advances reduced drilling times and boosted drilling productivity notably.

The service sector also played its part in reducing the cost of new projects. The collapse in upstream investment which began in 2014 resulted in a significant oversupply of equipment, labor and materials across the board. In response to this supply overhang, oil services companies offered deep rate cuts in order to survive and maintain the utilization of their rigs and equipment. Furthermore, greater collaboration between the operators and service companies improved the industry's ability to manage complex technical challenges and its overall project execution capability.

At the same time, industry-wide job-losses decreased the cost of labor, while lower input costs, such as for steel, reduced the cost of equipment and building appropriate facilities.

The mixture of smaller project footprints, improved efficiency, and lower input and service sector costs raised cost efficiency and capital productivity of the sector significantly. As a result, by 2017, our Supermajors Cost Index had declined by more than 41% compared with the level seen in 2014, when the Index reached its peak (*see chart 4*).

> Among the seven companies analyzed between 2011 and 2017, we found that Eni's performance improved the most, followed by Chevron and Total

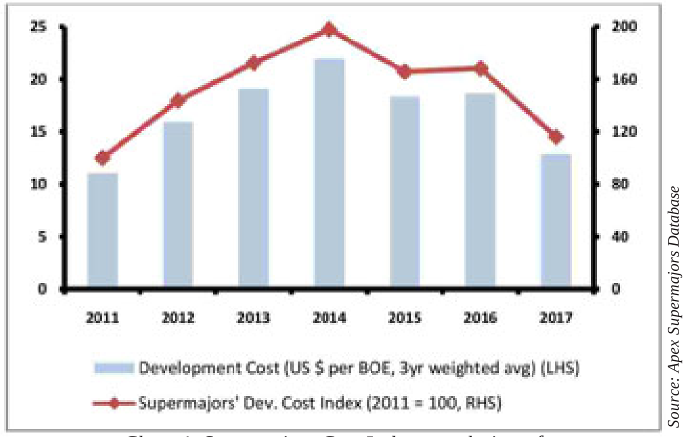


Chart 4: Supermajors Cost Index – evolution of development costs (2011 – 2017)

We estimate that about 35% of this cost reduction took place between 2014 and 2015, which largely reflects the reduction in service sector costs during this period. The remaining 65% took place between 2015 and 2017, reflecting various cost saving measures adopted by the industry, as well as a continued fall in service sector costs.

Despite this impressive reduction, cost was about 16% higher in 2017 than in 2011, when the industry was in the midst of significant cost escalation.

How individual supermajors have performed

The impressive decline in costs over the past few years for supermajors as a group masks considerable differences in the cost reduction achieved by individual supermajors (*see chart 5*). Among the seven companies analyzed between 2011 and 2017, we found that Eni's performance improved the most, followed by Chevron and Total. Although the three-year weighted average development cost per BOE went down for these companies over this period, it increased for the other four companies in line with the wider industry trend.

In our opinion, various actions taken in response to the oil price collapse and falling capital productivity, some as early as 2010, significantly

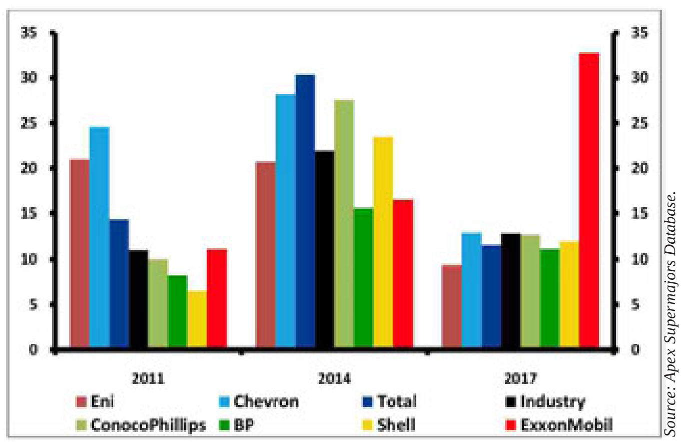


Chart 5: Supermajors Development Cost per BOE – 2011, 2014 and 2017

Note: Three-year weighted average, in US $.

improved Eni's development cost efficiency. For example, in order to manage costs better and negate the impact of sector-specific cost inflation, Eni started high-grading its portfolio, standardizing specifications, applying technologies that reduced drilling and completion times, and focusing on managing risks better and improving its project execution. These steps helped reduce its development cost per BOE by 55% between 2011 and 2017. As a result, by end-2017, Eni's development cost per BOE was 27% lower than that of the supermajors as a group, whereas it was almost twice the peer group average in 2011.

Chevron's development cost efficiency followed the wider industry trend, albeit at a different rate. While development cost per BOE almost doubled between 2011 and 2014 for supermajors as a group, Chevron's cost only went up by 15%. This was mainly due to improvements in capital stewardship and cost discipline, including greater use of technology to manage field performance and complex drilling projects, leveraging of existing infrastructure and facilities, and investing in targeted growth areas.

At the end of 2013, largely due to a number of major projects coming on-stream, Chevron reduced its capital investment budget for 2014. The pace of this reduction increased in 2015 and 2016 in response to declining oil prices.

At the same time, with major projects continuing to come on-stream, a combination of lower investment, portfolio high-grading, cost deflation in the wider industry, and its ongoing focus on capital stewardship, cost efficiency and project execution, enabled Chevron to reduce its development costs significantly. As a result, Chevron's cost efficiency increased by 47% between 2011 and 2017. By end-2017, its development cost per BOE was in line with the supermajors as a group, down from more than twice the peer group average in 2011.

> Looking ahead, 2018 may turn out to be the year when development cost deflation bottoms out, leading to a rise in the Index in subsequent years.

Between 2011 and 2014, the decline in Total's development cost efficiency closely followed its peer group average. During this period, in line with an almost doubling of costs for supermajors as a group, its development cost per BOE increased from \$14.3 to \$30.4.

At the end of 2013 Total, like Chevron, was coming out of an intensive capital investment phase, which led to it reducing its investment in 2014. This cut in capital investment deepened in the subsequent years as prices began to fall sharply. At the same time, greater cost discipline and improving capital efficiency became key strategic priorities for the company. These priorities – alongside industry-wide cost deflation, a continued focus on portfolio high-grading and a number of major projects coming on-stream – helped Total reduce its development costs per BOE by 62% between 2014 and 2017, compared with 41% for the supermajors as a group. As a result, looking at the period between 2011 and 2017 as a whole, we estimate that Total's cost efficiency improved by 19% during this period. By the end of 2017, its development cost per BOE had decreased from around 30% above the peer group average in 2011 to 10% below the group average.

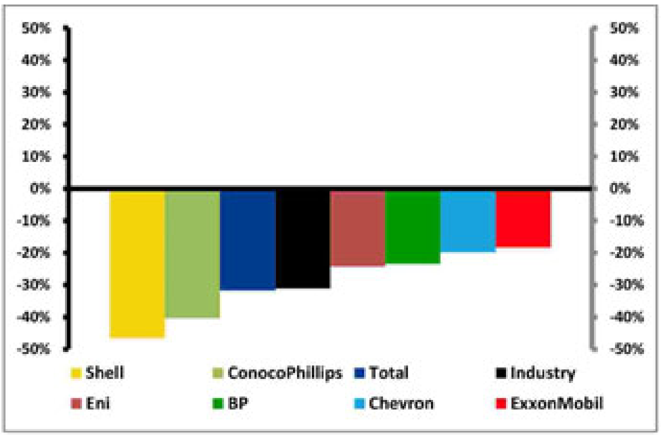
While these three companies bucked the trend, others have seen their cost efficiency decline during this period. ExxonMobil's development cost efficiency fell significantly following a downward revision of approximately 3.8 billion BOE of reserves, primarily due to low prices in 2016. As a result, ExxonMobil went from having one of the lowest development costs per BOE in 2011 to having the highest among the supermajors in 2017.

Prior to the collapse in oil prices, Shell's development cost efficiency had deteriorated dramatically, due to cost overruns and delays in many of its flagship projects, as well as industry-wide cost escalation. A significant write-down of reserves, particularly in its North American shale operations, also contributed to reducing Shell's cost efficiency. However, since 2014, renewed focus on cost control and capital discipline, portfolio high-grading, important strategic acquisitions, such as that of the BG group, and a number of major projects such as Gorgon (Australia), Lula (Brazil) and Kashagan (Kazakhstan) coming on-stream helped Shell to reverse this trend. As a result, despite the 83% decline in its development cost efficiency between 2011 and 2017, Shell's development cost was around 6% lower than the supermajors as a group in 2017.

Like Eni, having a strategic focus on cost control and capital efficiency long before the oil price slump enabled BP to moderate the impact of sector-specific cost escalations, whilst at the same time developing a portfolio of inherently more expensive resources. As a result, the growth in BP's development cost per BOE between 2011 and 2017 was smaller than that of companies like Shell, helping it maintain its relative cost advantage over some of its peers. During this period, its development cost per BOE went up by 36% compared with 83% for Shell.

In the case of ConocoPhillips, the general industry trend of cost overruns and escalations, along with greater emphasis on debt reduction, production and dividend growth rather than capital efficiency, were largely responsible for the development cost per BOE shooting up from \$10.0 in 2011 to \$27.6 in 2014. However, like its peers, just as it suffered from the industry-wide cost escalations prior to the fall in oil prices, the company also benefited from the cost deflation that followed the slump in prices. Furthermore, a number of major projects coming on-stream, such as APLNG, and greater focus on cost control and capital discipline helped the company improve its cost efficiency and more than halve its development costs in 2017 compared with 2014 levels.

In our analysis of how companies performed between 2016 and 2017, Shell, ConocoPhillips and Total came out on top (*see chart 6*). This suggests that companies whose development cost per BOE more than doubled between 2011 and 2014 were the ones achieving the greatest improvement in development cost efficiency between 2016 and 2017. While development cost efficiency improved for all supermajors



Source: Apex Supermajors Database

Chart 6: Changes in Development Cost between 2016 and 2017 (%)

Note: Negative percentage reflects reduction in development cost per BOE and therefore,improvement in development cost efficiency.

between 2016 and 2017, it increased by less than the peer group average for Eni, BP, Chevron and ExxonMobil. In the case of ExxonMobil, an 18% improvement in its cost efficiency between 2016 and 2017 helped the company moderate the impact of a significant write-down of reserves in 2016.

The recent revival of deep-water projects provides an initial indication of a broad-based recovery in upstream investment taking place across various sectors of the industry, not just in US shale. The latest reports from several global oil services companies also point to early signs of activity picking up and rates recovering elsewhere in the world. As rates in the service sector continue to improve globally in line with this broad-based uptick in investment, further efficiency and productivity gains – through technological innovation, a continued focus on cost management and structural cost reduction – will be even more crucial to offsetting this emerging inflationary pressure and keeping overall development costs down. While this seems to have been achieved so far in 2018, the industry's ability to continue to do so in 2019 remains to be seen. Therefore, in the absence of additional efficiency gains, 2018 may turn out to be the year when development cost deflation bottoms out, leading to a rise in the Index in subsequent years.

Challenges to sustain this cost reduction

Challenges, therefore, remain, not only in sustaining this cost deflation but also in preventing a recurrence of the cost escalation we have seen in the past.

During the previous growth phase, capital productivity declined significantly, as poor project execution caused cost overruns and delays, and a prolonged ramp-up in investment activities caused industry-wide cost escalation. We might see a repeat of this trend if capital discipline is not maintained as investment greenfield and relatively larger projects increases in 2019 and beyond.

What's more, protectionist measures such as tariffs on coal, steel and other components threaten to raise the cost of manufacturing equipment and building facilities significantly.

This potential upward pressure on costs will be moderated somewhat by cost-saving measures that are not dependent on third-party rates, such as optimizing logistics and production operations, simplifying processes, adopting lower cost drilling techniques, and so on. However, approximately 50-60% of the cost savings achieved by the industry in the last few years could be lost as a result of increased activity, higher rates, tighter labor markets and input tariffs, given that a third of this cost deflation resulted from lower activity and two-thirds from lower costs.

A new approach is therefore needed to mitigate the risk of rising costs and make cost savings more sustainable. Not only do we need greater collaboration between operators and service providers, we also need a more transparent and shared approach to risk allocation so that oil services companies are incentivized appropriately to find innovative ways to cut costs.

Several oil and gas players have already taken steps towards greater collaboration with their suppliers. For example, Equinor (previously Statoil) cited close co-operation with its suppliers as the main reason for the reduction in investment costs of its Johan Sverdrup project. Project owners also identified collaboration as one of the key drivers behind the 60% reduction in BP's Mad Dog phase 2 cost estimates.

Some oil executives believe that two-thirds of the cost savings achieved in the last few years can be sustained, even if upstream investment accelerates. Due to the risks mentioned above, we believe the potential for costs to escalate rapidly is high, especially if the industry tries to manage costs in the same way it has for the last 20 years. However, the threat of rising costs can be managed through greater collaboration and risk-sharing between operators and their suppliers. This new model of collaboration with appropriate incentive structures must be guided by the overarching mantra of '*value accretive volume growth*' to prevent the recurrence of the runaway cost escalations of the past and make the industry's activities more resilient to adverse price movements.

About the Author

Muktadir Ur Rahman is a highly experienced consultant with considerable expertise in project economics, modelling of upstream projects and portfolios, capital raising activities, commercial/contract negotiation strategy, and regulatory compliance. He has worked extensively with major oil and gas companies worldwide on a variety of projects, from undertaking independent reviews of economic models and modeling various fiscal regimes to leading investment appraisal, risk and sensitivity exercises to identify commercial value drivers for clients' commercial teams.

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Prediction of Centrifugal Compressor Performance in Off-Design Condition

Introduction

Centrifugal compressors are a vital component within process plants and compression machines are widely used in upstream as well in mid-stream plants accomplishing critical missions toward meeting overall production goals.

Compressors are often one of the most important assets in these plants considering their capital investment costs, and the critical impact caused if temporarily unavailable along with their related maintenance and repair costs.

From this perspective it is evident how the capability to understand if the machine is running and working properly assumes a primary role. The ability to detect early indicators of potential malfunctions and understanding their causes and possible remedies gives a valuable contribution toward plant proficiency, allowing overall operational costs to be minimized.

This growing trend is generally known as predictive maintenance. Today the predictive approach is well present across all of the involved industries and applied over several types of machinery. For many of the most common centrifugal machines the predictive techniques commonly implemented are connected to the vibrational and structural dynamic aspects of the machine's rotor operational conditions. This approach, being phenomenological, can be applied in the design stage where insight is given by OEMs to rotor dynamics but often it assumes more practical and empirical form at operation floor, where basically the machine vibrational parameters are measured and compared to acceptable limits and used merely for alarm triggering. Predictive strategies based on the analysis of performance are increasing their presence as a tool for diagnostics and evaluation of machine health status during operational time. For centrifugal pumps, for instance, the use of machine model for the purpose of comparison of measured performance to design performance is relatively easy and straightforward. For the centrifugal compressor the same process is more complex because of the dependency of compressor performance from the gas mix composition and operative inlet conditions (inlet pressure and inlet temperature). For centrifugal compressors an approach based on performance assessment requires a more complex machine model that should embed and couple several calculation capabilities from aeromechanics to thermodynamics.

In fact, one of the main difficulties for the analysis of centrifugal compressors' operative performances arises from the need to have ready and available the compressor performance map adjusted to actual inlet conditions. Usually expected performances are described in terms of graphs of discharge pressures, discharge temperatures, polytropic heads, efficiencies and absorbed power, related to the design inlet gas conditions. In general it may happen that inlet conditions, in the field, are different from specification conditions defined in the machine data sheets. A somewhat diffused practice consists of trying to reduce the complexity of the problem considering the compressor head as invariant with inlet gas conditions, and applying simplified machine formulas. While this method holds for very low pressure ranges and constant gas mixes, it introduces considerable errors as soon as the pressures go up and the gas mix variability is introduced into the problem.

In these situations, in order to assess compressor performance it is then necessary to proceed to adjust the design performance to operative conditions taking into account all the complexity of the problem and then compare that to measured values. This is basically the approach also indicated on PTC10.

The main purpose of this paper, is to present a general method and calculation tool for prediction of centrifugal compressor field performances in off-design conditions. All numerical evaluations executed with Cmap software reported in this paper have been developed using the most recent thermodynamic theories and machine aero-mechanical models in accordance to the ASME PTC10 (Performance Test Code on Compressors and Exhausters) standard.

Methodology

Here we provide a simple explanation of the calculation process used to evaluate the compressor performances. As a starting point we can consider that, for a centrifugal compressor, performances are strictly linked to the inlet gas conditions. This consideration is valid both to the design and off-design performance. The starting point is the availability of a centrifugal compressor performance curve, the relevant gas mix composition and thermodynamic conditions (pressure and temperature). Having this input data available, the software will perform all complex calculations in a fully automated way and will produce the expected compressor performances for inlet pressures, inlet temperatures and gas mix compositions different for design / reference ones.

Item	Gas name	Symbol
1	Acetylene	C_2H_2
2	Ammonia	NH3
3	Argon	Ar
4	Benzene	C_6H_6
5	Iso-Butane	C_4H_{10}
6	n-Butane	C_4H_{10}
7	Iso-Butylene	C_4H_8
8	Carbon Dioxide	CO_2
9	Carbon Monoxide	CO
10	Chlorine	Cl_2
11	n-Decane	$C_{10}H_{22}$
12	Ethane	C_2H_6
13	Ethyl Acohol	C_2H_5OH
14	Ethylene	C_2H_4
15	Helium	He
16	n-Heptane	C_7H_{16}
17	n-Hexane	C_6H_{14}
18	Hydrogen	H_2
19	Hydrogen Chloride	HCL
20	Hydrogen Sulphide	H_2S
21	Methane	CH_4
22	Methyl Alcohol	CH_3OH
23	Nitrogen	N_2
24	n-Nonane	C_9H_{20}
25	Iso-Pentane	C_5H_{12}
26	n-Pentane	C_5H_{12}
27	n-Octane	C_8H_{18}
28	Oxygen	O_2
29	Propane	C_3H_8
30	Propylene	C_3H_6
31	Sulphur Dioxide	SO_2
32	Water Vapour	H_20
33	1-Butene	C_4H_8
34	2-Butene	C_4H_8
35	1.3 Butadiene	C_4H_6
36	Ethyl chloride	$C_2H_5C_l$
37	Methyl Chloride	CH_3C_l
38	Pentylene	C_5H_{10}
39	Propadiene (Allene)	C_3H_4
40	Methyl Acetylene (Propyne)	C_3H_4
41	Toluene	C_7H_8
42	Freon R134a	CH_2FCF_3

Table 1 Gas components

From a fluid dynamic point of view a strict similarity of flow at each performance point is necessary. For this reason the non-dimensional parameters – head coefficient, flow coefficient and Mach number – must be conserved.

The proposed method then needs the following inputs:

a) Reference/Design compressor maps: in general these maps provided by the machine OEM, give a reliable indication of the machine capability and are considered here as starting point. It is clear that in case these input data should be affected by error, these error shall be propagated in the outputs generated by this method. OEMs usually supply two different machine maps related to different moments of the compressor manufacturing process. “Expected” maps are usually issued in the commercial/design stage, while tested maps are issued at the end of the manufacturing process when the compressor is shop or field tested. In general, both maps may be used as input for the method although “as tested” maps may be considered preferable.

b) Reference input conditions: reference/design maps are linked to specific inlet conditions such as inlet pressure, inlet temperature and gas mix composition. This set of data shall be stated in order to proceed to off-design calculations.

c) Off-design input conditions: these are the conditions at the compressor inlet (pressure, temperature and gas mix composition) in which the new performance should be obtained. Off-design conditions may be some alternative inlet conditions to be considered in the compressor design stage, or may be the actual inlet condition in some specific time during compressor operation.

With the above described inputs the method proceeds to calculate the compressor performances in off-design inlet conditions. Performance obtained as output from the described method, shall be referenced in the following paragraphs as off-design conditions i.e. design performance adjusted to off-design operative conditions. When reference is made to off-design performance in off-design operative condition during operational time, these performances shall be indicated also as “actual” performance. Calculation of off-design performance requires the capability to extract the invariant information that describe compressor behavior and that use this information to rebuild the performance in new conditions. These calculations are intimately coupled with thermodynamics of gas compression and thermodynamics of real gas mixtures, so that a variation in each component of the gas mixture is potentially able to manifest its effects, as well as a change of the inlet pressure and temperature. The connection among these different modeling areas allows the method to provide an accurate prediction of the compressor performance. The method does not require information about the internal parts of the machine, and in this sense it should be not considered as a design tool but more correctly as an analysis tool that starts its job just after the completion of the machine design stage.

Calculation algorithms used are able to predict both machine behavior and thermodynamic real gas properties in off-design conditions. Below the list of gas can be configured:

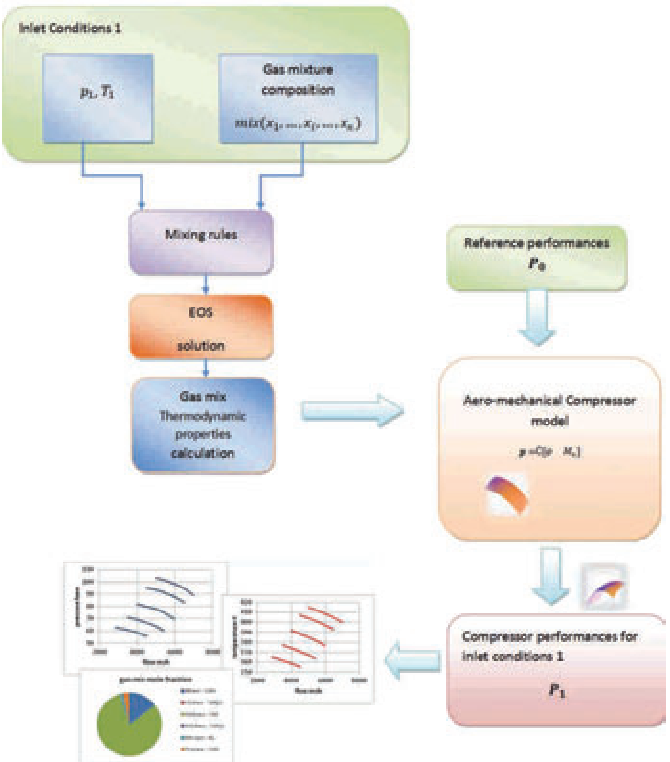


Figure 1: How Cmap works

Case Study: Prediction of Performance in Off-Design Conditions

This paragraph describes how the presented method is applied using the Cmap software tool.

Two real cases will be presented. The compressors under study were running under off-design inlet conditions. The analysis developed with Cmap allowed to obtain the performances in these off-design conditions and a comparison to measured field values.

In these case studies, the compressor performances map in design condition were available for both machines. The following figures and table show the design maps (discharge pressure vs inlet flow) for compressor 1 and compressor 2 and relative design inlet conditions:

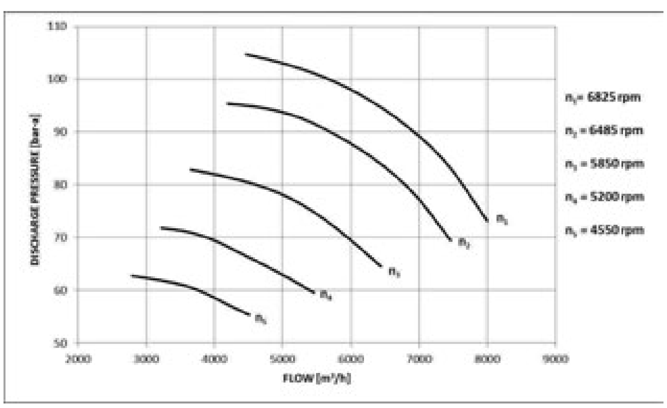


Fig 2: design map compressor 1: discharge pressure vs inlet flow

The following table indicates the inlet design gas conditions of Compressor 1.

• Pressure:	40.2 bar a
• Temperature:	50°C
• Gas Mixture (Mw 19.24 g/mole):	
- Methane	80.51%
- Nitrogen	1.46%
- Ethane	14.69%
- Propane	3.19%
- I-butane	0.07%
- N-butane	0.08%

Table 2: Inlet design gas condition Compressor 1

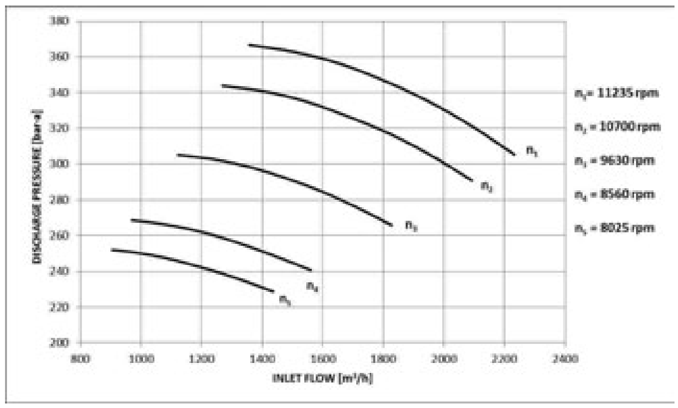


Fig 3: Design map compressor 2: discharge pressure vs inlet flow

The following table indicates the inlet design gas conditions of Compressor 2.

• Pressure:	150 bar a
• Temperature:	37°C
• Gas Mixture (Mw 19.1 g/mole):	
- Methane	87%
- Nitrogen	1.2%
- Ethane	3.5%
- Propane	0.8%
- I-butane	0.5%
- N-butane	0.5%
- Carbon Dioxide	4.5%
- I-pentane	0.1%
- N-pentane	0.1%
- N-octane	0.1%
- Hydrogen Sulfide	1.7%

Table 3: inlet design gas condition Compressor 2

Considering the above maps, the expected performance curves in the off-design conditions have been calculated.

The following tables are indicative of the off-design inlet condition for Compressor 1 and Compressor 2.

- Pressure: 43 bar a
- Temperature: 47°C
- Gas Mixture (Mw 19.64 g/mole):

- Methane	78%
- Nitrogen	0.5%
- Ethane	17.9%
- Propane	3.5%
- I-butane	0.03%
- N-butane	0.07%

Table 4: Inlet off-design condition Compressor 1

- Pressure: 154 bar a
- Temperature: 30°C
- Gas Mixture (Mw 20.1 g/mole):

- Methane	83.7%
- Nitrogen	1.1%
- Ethane	4.7%
- Propane	2.8%
- I-butane	0.4%
- N-butane	0.4%
- Carbon Dioxide	4%
- I-pentane	0.5%
- N-pentane	0.2%
- N-octane	0.3%
- Hydrogen Sulfide	1.9%

Table 5: Inlet off-design gas condition Compressor 2

The following picture compares the performance curves (discharge pressure vs inlet flow) in design and off-design condition:

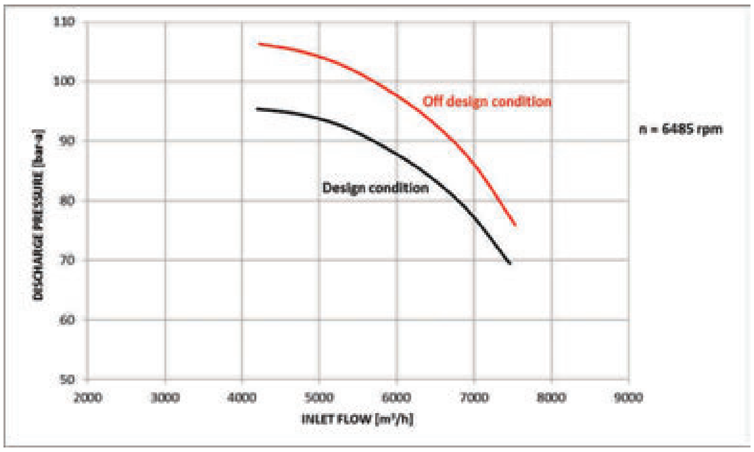


Fig 4: Comparison of discharge pressure between design and off-design condition (Compressor 1)

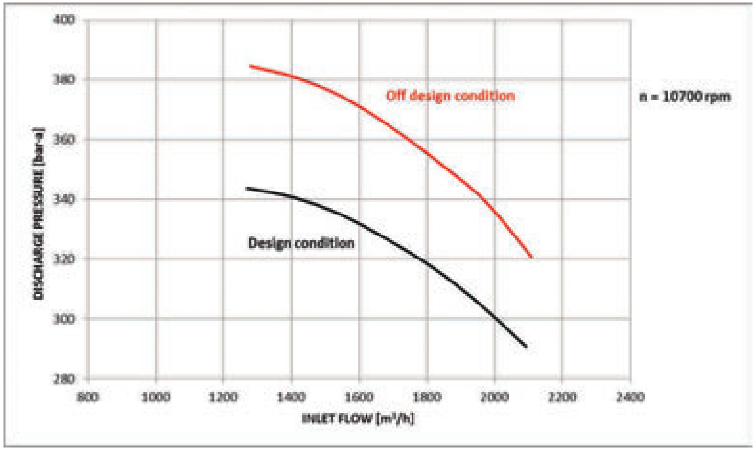


Fig 5: Comparison of discharge pressure between design and off-design condition (Compressor 2)

The Cmap software allowed the calculation, at the actual flow, the values of expected pressure, temperature, Head and efficiency in the actual (off-design) conditions and then compares it to the measured ones.

With reference to the field values, the following table compares the pressures and temperatures as read from transducers to the value predicted by Cmap software:

Compressor 1

Properties	Field value	Cmap predict value	Percentage error
Discharge pressure [bar a]	98	97.6	+ 0.4
Discharge temperature [°C]	122	123	- 0.8

Compressor 2

Properties	Field value	Cmap predict value	Percentage error
Discharge pressure [bar a]	240.5	263.7	- 8.8
Discharge temperature [°C]	99	102	- 2.9

The same comparison has been executed for Head and Polytropic efficiency.

In the previous tables it can be noted how for Compressor 1 the maximum error calculated is less than 1% and for Compressor 2 the error calculated is about 9%.

The analysis indicates than that Compressor 1 was running with operative performance aligned with design expectations. Compressor 2, differently, was running with performance not aligned with design expectation. This comparison gives to the compressor analyst an important quantitative indication on the machine health status and should drive the analysis towards an understanding of possible causes that may justify the observed difference.

The analysis developed using Cmap also allowed to obtain an evaluation of the efficiency deviation (difference between the actual compressor efficiency and the expected efficiency in the actual operative conditions). Time trends of calculation results provided a useful analytical basis for compressor maintenance decisions. The method has been advantageously used to predict compressor performances and to support planning of machinery maintenance activities.

Cmap allows compressor performance prediction using different equations of state (EOS) depending on the gas mix considered in the calculation. For hydrocarbon gas mixture Lee-Kesler or PR EOS can be used. For Freon R134a the MBWR EOS shall be selected to determine the thermodynamic properties of the operating fluid.

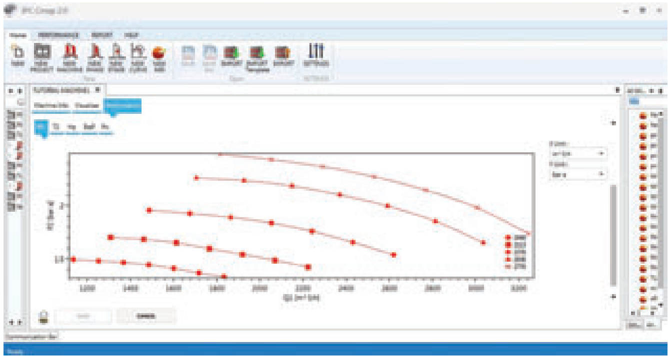


Fig 6 Screenshot Cmap 2.0

Conclusions

Experiences with real machinery showed that compressor performance prediction obtained with Cmap software are in very good alignment with OEM predictions and field measurement for machines in good condition. Also experience showed that in most cases the deviation of a parameter such as the efficiency, indicates the eventuality of a problem on the machine.

The proposed method may be used in a fully automated way, and could provide high benefits especially for those machines that work in high and very high pressure ranges and under rapidly time varying process conditions.

Automated application of Cmap gives the possibility to provide a continuous monitoring of the machine performance and therefore exert an automated surveillance and diagnostic. Also the compressor protection from surge can be automatically and continuously updated to actual inlet conditions overcoming limitation of actual systems (see SPS surge protection system - IPC™, all rights reserved).

Methods proposed and described in this paper can allow to:

- Predict the performances of a centrifugal compressor in off-design condition. The prediction of compressor performances is accurate even at high pressures, where the ideal gas theory commonly used introduces considerable errors.

- Predict the modification of surge points in actual operative conditions, with different inlet pressure and temperatures, different operative gas and to implement advanced protection from surge.

- Have useful indications on the health of the compressor (diagnostics) based on the capability to analyze the performances and efficiency of the machine in a simple and immediate way.

- Support decisions and planning of predictive maintenance and activities.

PIPING PRODUCT

A number of new developments to move oil and gas has been seen over 2018, each of which will boost the economics for the countries involved.

Nigeria is looking to expand its pipeline network to allow for more exports. In February, Maikanti Baru, head of Nigeria's state-run oil and gas firm NNPC, called on private investors to help repair and build up the country's pipeline infrastructure. According to Baru, more pipelines would enable Nigeria to export more oil. Baru told the board of NNPC's downstream unit, Nigerian Pipeline Storage Company (NPSC), to form partnerships with the private sector and double the number of its pipelines over the next 10 years.

In April, NNPC revealed that it had awarded two pipeline construction contracts. The contracts went to two indigenous firms, Oando Plc and OilServe, and a consortium of China Petroleum Pipeline Bureau and Brentex.

Oando's first contract is for a 200 km pipeline that is part of a longer, 614 km line linking Ajaokuta, Kaduna and Kano (AKK pipeline). The second pipelin os also 200 km long. These two contracts are part of a package of three with a projected total value of $2.8 billion. Once these lines are built, they will allow a better supply of natural gas to the local market and possibly a better supply to the West African Gas Pipeline (WAGP).

The AKK pipeline received an 85% financing guarantee from China's state-owned petroleum company CNPC. The remaining 15% of the funding for the pipeline will be provided by the two consortiums engaged in the construction of the first 400 km of the pipeline.

Later, Nigeria and Morocco signed a joint declaration on June 10, that lays out the next steps for the completion of a gas pipeline deal, according to Moroccan state news agency MAP. The two countries agreed to the pipeline in December 2016 and launched feasibility studies ending with a plan to build the pipeline onshore and offshore.

The pipeline will be 5,660 kms long and traverse a combined onshore and offshore route for economic and security reasons. The construction on the pipeline will take place in phases. The next step toward bringing the pipeline to fruition has Morocco and Nigeria launching the FEED

to involve countries that will be crossed by the pipeline in the Economic Community of West African States (ECOWAS) and to determine the amount of gas available for export to European off-takers.

Moving north, Cyprus and Egypt announced that their planned pipeline to connect the Aphrodite gas field offshore Cyprus to Egypt's LNG facilities will cost between $800 million and $1 billion. Cyprus's Energy Minister Yiorgos Lakkotrypis said Cypriot gas would be used in part for domestic consumption and in part for export. Lakkotrypis said a final agreement on the pipeline would be signed as quickly as possible but did not specify when. Meanwhile, Egypt hopes to halt gas imports by 2019 and achieve self-sufficiency.

The managing director of the Cameroon Oil Transportation Company (COTCO), Johnny Malec, said the volumes of crude transported through the existing Chad-Cameroon pipeline could double by 2022. An increase in crude being shipped through the pipeline would be a boon for Cameroon's economy.

The increase in production would come for new operators that have arrived in Chad over the past few years. Since the pipeline's inception, the Chad-Cameroon pipeline has shipped 680 million barrels of crude. There is also the chance that crude from Niger could be shipped through the pipeline. There has been talk of a pipeline being constructed from the oil fields of Niger to the pipeline in Chad, shipping it on through the Chad-Cameroon pipeline to the coast of Cameroon.

A lot of activity on the pipeline front is coming out of East Africa as both Kenya and Uganda look to get their oil and/or gas to market. This August, Tanzania and Uganda said the Environmental Social Impact Assessment report for the East Africa Crude Oil Pipeline is in its final stages and due for completion by the end of the year. The pipeline will take Ugandan crude from the Lake Albert region to the Port of Tanga on the Tanzanian coast.

The completion and approval of the report will give the green light for Total to start of the implementation of the project. The pipeline is expected to cost $3.5 billion and is planned to have the capacity to transport 216,000 bpd. According to earlier negotiations, Uganda will pay Tanzania $12.20 for each barrel flowing through the pipeline.

Tanzania and Uganda signed another agreement for the construction of a pipeline, this time for a natural gas pipeline. The signing of the natural gas pipeline agreement was the culmination of work that began during the first Tanzania-Uganda meeting held in April 2017, in which the two agreed on a number of memoranda and cooperation frameworks. This pipeline comes just 15 months after the oil pipeline agreement between the pair. This will be the first trans-border gas pipeline in East Africa since the extraction of natural gas commenced in 2004 at the SongoSongo Island in Tanzania.

"Tanzania and Uganda signed another agreement for the construction of a pipeline, this time for a natural gas pipeline … This will be the first trans-border gas pipeline in East Africa since the extraction of natural gas commenced in 2004 at the SongoSongo Island in Tanzania."

Uganda-Tanzania Proposed Pipeline

The planned 80,000-100,000 bpd heated pipeline to traverse 821 km from Kenya's oil fields to the coast at Lamu for export, is scheduled to be operational by 2022. However, the project has hit a number of snags along the way. Project developer Tullow Oil said the central processing facility design is being optimized and port facilities at Lamu are advancing, but securing land rights agreements along the pipeline route, and water use issues have to be solved. Meanwhile, some progress was made with the Wood Group being awarded a contract for the design of the pipeline.

More good news for East Africa is on the horizon as the UAE announced its plans to build a pipeline connecting Eritrea to Ethiopia. The pipeline will run from Eritrea's port city of Assab to Ethiopia's capital Addis Ababa. Chinese firm Poly GCL began extracting crude oil on a test basis from reserves in Ethiopia's southeast in June and will need access through Eritrea to the coast in order to export it.

Finally, the government of Zambia and Angola have signed a $5 billion deal to construct an oil pipeline that will bring oil products to the energy hungry nation from its oil rich neighbor. It was reported in October that the pair are set to resume talks on the construction of the on-again, off-again multi-product pipeline. Zambian Minister of Energy Mathew Nkhuwa said that government is ready for the project and that feasibility studies will start before the end of the year. The pipeline will also bring in petrol, diesel and gas used for cooking.

By Damian Ondo Mañe Nchama

Oil and Economic Development in Equatorial Guinea

50 Years Since Independence

(1968-2018)

Overview

Equatorial Guinea (EG), is a former Spanish colony whose economy, pre-and-post independence was based on its agriculture and forestry sector, that is until the advent of oil production in the early 1990s. The country became one of the fast-growing economies on the continent and the third largest oil producer in sub-Saharan Africa (SSA) through 2014, moving from an agriculture-based to oil-led growth economy over 50 years.

Right after independence in 1968, to help build its economy the country immediately became members of the International Monetary Fund (IMF) in 1969 with a quota of SDR 8 million generated through exports of cocoa, coffee, palm oil, and timber. These activities were heavily dependent on foreign labor. Important economic reforms followed thereafter, including renewal of foreign labor contracts and mobilization of migration from continental EG to work in cocoa plantations in Malabo. The integration to regional economic institutions, BEAC and CEMAC, as well as the signing of petroleum exploration contracts, coupled with the establishment of a two-phased national development plan 2020 has transformed EG. The country took advantage of high commodity prices (1995-2012) to increase oil production and diversify within the oil and gas sectors, which helped to accumulate a large amount of fiscal reserves that enabled the authorities to effectively undertake the first phase building modern infrastructure (2008-2012) of the National Development Plan (NDP) 2020.

Midway through its second phase diversifying the economy (2013-2020), the country was confronted with a long and unexpected oil price shock beginning in 2014, accentuated by a significant drop in oil production and capital expenditure cuts aimed at containing the resulting large fiscal deficit. As a result, the country's GDP has been decreasing over the 2014-17 period. The macroeconomic buffers built up during the boom period, including substantial government deposits, coupled with very low external and public debt were not sufficient to cushion the impact of the 2014 oil-price shock but growth is expected to resume gradually beginning in 2019, given measures being undertaken by the authorities, including discussions with the IMF and other development partners for financing support.

Equatorial Guinea, like numerous developing countries, is confronted with a host of challenges and opportunities notably grounded on historical background, geographical dislocations on the Gulf of Guinea,

abundant natural resources, and policies implemented prior and since independence. All make EG's self-governing and economic development very challenging.

I. Pre-Independence Development

Throughout its pre-independence period 1778-1968, Equatorial Guinea's social and economic development were driven to a larger extent by external factors and actors. Although relatively small in extension with 28,051 sq km, and a population of about 1,221,490, the strategic location of the islands pertaining to EG in the Gulf of Guinea is a comparative advantage for the country. It provides the country with great potential as a hub for trade and logistics. In addition, it provides the country with an additional 314,000 sq km of exclusive maritime area with a great potential in hydrocarbon resources, minerals and fisheries. At the same time, there are challenges as well against economic development, notably with regard to labor-intensive development, attracting private investors, and the distances between its several islands and to the mainland part of the country (over 300 km) makes it hard to manage local economy.

Source: Divine Chocolate

The lack of such administrative capacity and economic prowess, especially on mainland EG, is linked to the pre-independence era, as the country had no modern administration for a long period of time. While limited administrative capacity and economic viability was developed on the island of Bioko starting in the late 1850s, administrative capacity improved on continental EG only after the Spanish Civil Wars (1936-39). The country's steady production of cocoa leading up to independence was the result of favorable conditions such as Spanish subsidies, premium prices, technical know-how and labor supply largely provided by foreigners. This stable cocoa production leading up to independence made the country one of the largest producers of cocoa in sub-Saharan Africa.

Post-Independence Development

The economic developments starting in 1968 through to 1978 were very challenging. In 1969, violent anti-European demonstrations on the continental part of the country led most Europeans to leave Equatorial Guinea one year after independence, severely dislocating the economic course of the country. By the end of 1972-73, in spite of lack of data, it is estimated that cocoa production declined by 53% (17,000 tons), compared to the 1968-69 annual production, notably due to the start of the departure of Nigerians (basic labor force in almost all cocoa plantations), plus limited available financing. These unfavorable conditions also impacted negatively the production of coffee. During this period, coffee production became almost nonexistent. In addition, pre-independence conditions such as those under bilateral trade and payment agreements with Spain, and the labor agreement with Nigeria, were no longer existent at the end of this period. Likewise, the Spanish technical know-how and financing support for the cocoa sector had left the country as well. One year after its independence, external factors – such as the Biafra war of 1969 – increased tensions between the contracted Nigerian labor force and the newly independent EG. More so was the continued decline of relations between Spain and EG that same year worsening the labor force situation and the business climate. In addition, the country had completely used its reserves for maintenance and construction of new infrastructures. The country's public finance management exacerbated the situation further due to limited administrative capacity, delays in renewing foreign labor contracts, and lack of an investment plan to undertake post-independence key infrastructure needs. As a result, a continuous yearly decreasing income could not be avoided. During this period, the country's GDP declined slightly to $64 million by 1974 from $67 million at independence.

II. Bilateral, Multilateral Assistance and Reforms

Equatorial Guinea implemented various reforms starting in 1980 through 1993 and received multiple technical assistance facilities during this period, including rehabilitation of 5,000 hectares of land for cocoa production financed by the African Development Fund in 1979. Efforts were made to attract Spanish plantations managers and investors to the country in spite of the challenges including outdated machinery and buildings, lack of a qualified labor force, irregular provision of inputs (insecticides and fungicides), these all leading to the steady decline of agricultural outputs. Additionally, the efforts through the banks' credits to plantation owners were fruitless, as such credits were unrecoverable due to slow return on plantations' investment and the high rate of owners re-abandonment of their plantations, often more interested in recovering their assets. The unrecoverable loans and the commodity price crisis of the 1980s led to a banking crisis in EG at the end of the 1980s, and the two banks in the country – Banco de Credito y Desarollo (BCD) and Banco Exterior de Guinea Ecuatorial (Guinextebank) – became insolvent and were liquidated. The country's GDP during this period reached its lowest level after independence at $36 million in 1981. In 1985, the country became a member of the Bank of Central African States (BEAC), and of the Central Africa Economic and Monetary Union (CEMAC) in its effort to get a convertible currency and proper economic exchanges within the sub-region. The country devalued it former currency, the Ekpwele, and adopted a new currency, the CFA Franc. The devaluation of the Ekpwele by 82% exacerbated the country's economic situation during the mid-1980s by increasing the prices of needed imports of goods and services against the struggling agricultural sector. The country's new currency, the CFA franc was also devaluated by 50% in 1994 because of the commodities and debt crisis. The benefits from those assistances and reforms were insignificant, the country still faced a pessimistic weak medium-term outlook until the discovery of sizeable hydrocarbon reserves in the early 1990s. Nonetheless, the commercial exploitation of such discovery which consolidated in 1991 did not start until 1995 and began leading the country's exponential growth from then forward for over a decade thereafter. As a result, in 1996 the country's growth rate was estimated at 64%. The key role of oil in the world economy, and the country's considerable oil reserves have created a greater link between the global and the Equatoguinean conomy, an interlink that includes new challenges and opportunities.

III. Oil Development and New Source of Income

The development of oil in Equatorial Guinea contributed positively to the country's growing income and to it economic growth beginning in 1995. Based on GDP alone, Equatorial Guinea had one of the fastest GDP growth rates during the last decade. The development of oil in the country can be traced back to the colonial period. Encouraged by the island of Bioko's proximity to Nigeria, currently a giant oil producer whose exploration started in the late 1950s. Under Spanish administration, license blocks were drawn and a bidding process was held. The first exploration licenses were granted to a group led by Mobil and Spanish Gulf Oil, however the exploration's commercial viability was low. In the 1970s, exploration activities were disrupted because of anxiety over the delimitation of offshores waters with neighboring countries, and the oil crisis during the 1970s deteriorated the investment climate.

In anticipation of launching oil exploration in 1982, with external assistance in the oil sector from the World Bank, the United Nation Development Program, and government commitment, a new petroleum law was adopted in 1981, and a production sharing contract model was approved a year later in 1982. On this year, a bidding round was launched and a year later the Alba field was discovered by Guineo-Española de Petroleo (GEPSA) a joint venture then between Hispanoil (now Repsol) and the government of EG. However, the conducted feasibility studies completed in 1986, classified the field as marginal. Four years later in 1990, the company's contract was rescinded by the authorities because the company delayed operations, and violated exploration agreement clauses. The country's commitment remained unshakeable, as in that same year a new Production Sharing Contract (PSC) was signed with Walter International. The company proceeded with exploration without delay and by the end of 1991, production began with an estimated 3,000 barrels per day (bpd) of condensate. Another PSC was signed in 1992, with ExxonMobil.

Oil production output grew exponentially starting in 1996 following the discovery of the Zafiro field on block B, and within a year field production doubled with production reaching 83,000 bpd by the end of 1998. The country's GDP shot up to $442.3 million from $141.8 million in 1995 (*c*) as a result. At its highest peak in 2002, Zafiro produced an estimated 300,000 bpd of oil. Although production had decreased significantly since it peak, to an estimated 109,000 bpd in 2012 (Ministry of Mines), Zafiro remained the country's highest daily producing field. Production further increased in 2000 with new discoveries in the previous year in blocks F and G of the Ceiba field located off the coast of continental Equatorial Guinea by Triton Energy (acquired by Hess in 2001). These major oil developments helped EG record fast growth starting with an estimated GDP of $232.4 million in 1996 and rose exponentially to $10.08 billion by 2006 .

During this period of increased oil exploration and production in Equatorial Guinea, Walter International cashed out in 1995, selling its rights to the Alba plant to CMS Oil and Gas and Nomeco. The companies operated the Alba plant until 2002, before selling their rights to Marathon. The Alba field is the country's first discovery and remained an important contributor to EG's output. Marathon also ventured out with Equatorial Guinea's national gas company Sonagas to produce Liquefied Natural Gas (LNG). The company's others ventures includes, Liquefied Petroleum Gas (LPG), and Methanol. In later years, Hess partnered with Tullow oil and Equatorial Guinea's national oil company Gepetrol as operators in the Okume complex. The first oil production from this complex was achieved in 2006, that same year, EG adopted a new petroleum law, outlawing gas flaring to prioritize domestic uses, and raising revenues. In 2009, Ophir announced a gas discovery on Block R and two years later in 2011, Noble made a similar discovery on Block O. In 2017, Kosmos energy acquired the Ceiba field and Okume complex from Hess.

IV. Recent National Economic and Social Development Plan

Recent development has been dominated by the construction of large infrastructures mostly by Chinese companies under the implementation of the National Development Plan (NDP). The construction of infrastructure has contributed greatly to the non-oil sector, although of significant importance, it is highly correlated with the country's oil revenues. The plan was adopted during the Second Economic Conference in 2007 and is set to guide the country's economic strategy up to the 2020s. The setback caused by the 2014 oil price shock to the implementation of the plan's Second phase will certainly lead to a review or update of the plan in the near future. The plan identified potential sectors: energy, fishing, agriculture, tourism, financial services, manufacturing and mining. However, it neglected some key issues from the outset that must be addressed to properly execute its vision. Those issues include tax administration, budget accounting, internal auditing, fiscal management, revenues administration, and legal administration. Many of the sectors identified within the NDP although promising, required a detailed implementation mechanism and creation of structures through which to operate.

As contemplated on the NDP 2020, the implementation of the second Phase of the plan is expected to undertake the diversification of the economy away from the oil sector, including into agriculture, farming, manufacturing, fishery, and the tourism sector, all of which have great potential, notably the latter with considerable facilities and sites already in place. This sector has certainly benefited from new infrastructure; however, it still faces regional competition and could benefit greatly from tourism enhancing policies and marketing. Other sectors identified, such as aquaculture, financial services and unexploited minerals are more promising.

As a key financing component of EG's economic diversification strategy, a Memorandum of Understanding (MOU) framework was signed between Equatorial Guinea and China in 2006, through which an oil sales agreement was signed. EG would sell oil to China and the funds were to be deposit at EG's account in Exim Bank that would generate account payables to all services Chinese would provide to EG. In addition, China opened a line of credit estimated at $2 billion from the Exim Bank at 5.5% interest, giving the country additional financial leverage to undertake its massive infrastructure needs.

Currently, Equatorial Guinea continues to suffer from the impact of the 2014 commodity price shock in spite of the recovery of oil prices this year. The growth rate today has declined at an estimated 43%, compared to 2013 GDP of $22 billion. As accurately predicted by Bloom & Sachs (1998), countries such as EG and Mozambique who lead the SSA' s economic growth with respective average rates of 8.4% and 5.5% between 1990s and 1998, will suffer setbacks when the prices of the few export commodities they rely on fluctuate, which has been the pattern of African's modern economic development. EG's need for diversification is more urgent now than ever before to restore its fiscal imbalances and recover its growth trend.

According to the recent Human Development Report, Equatorial Guinea presents a mixed picture. The country is classified as a high-income country, its GDP per capita makes EG one of the richest countries in the world, but its Human Development Index rating of 0.592 shows a minimal improvement from its 2000 score of 0.527. Although, the country's indicators such as life expectancy and adult literacy, and gross school enrollment have improved compared to the first decade after independence, more remains to be done, notably on data quality.

V. Conclusion

As this paper's aim is to encourage discussion and not to present a wholistic analysis, Equatorial Guinea has successively implemented reforms and received financial and technical assistance to revive its economy after the recession of the 1970s. It has achieved unprecedented growth rates and attained significant diversification within the oil sector. The country's diversification effort within the oil sector concern gas related products, natural gas, methanol, LPG and LNG. The gas sub-sector has recently provided the country with needed income. EG is the second largest natural gas producer in sub-Sahara Africa behind Nigeria (*US EIA*). The country's gas potential is one of the main reasons why Equatorial Guinea's medium- and long-term prospects have remained favorable.

Given the fluctuation of oil prices and its impact on the country's economy, it is important for EG to further diversify its economy by enabling a private sector that will seek opportunities in the strategic sector identified in the NDP 2020. A successful completion of the ongoing economic reforms and negotiations with the IMF and other development partners for financial and technical assistance should help rescue the economy out of its current recession since the oil price shock in 2014 and unleash sufficient financing needs to forcefully initiate the transformation pase of the NDP. Furthermore, Equatorial Guinea must address basic issues such as a limited labor force, lack of technological know-how, competitiveness, and a small domestic market by fostering integration and rigorous trade exchange within the region. It must also address administrative deficiencies that have haunted the country since independence, notably with a lack of statistics on economic activities, in addition to further challenges such as youth unemployment.

From the Author

This article was prepared to encourage social and economic development discussions on Equatorial Guinea as the country celebrates 50 years of Independence. I'm grateful to Eustaquiano Ndong Ondo Bile, senior advisor at the IMF for his comments. The views expressed in this document do not necessarily reflect the views of any institutions. I can be contacted at damianondo@gmail.com

References to data cited are available on request.

Exclusive Interview

DRILL or DROPS says Minister Gabriel Lima

In an exclusive interview with *Petroleum Africa* on the sidelines of the Africa Oil & Power Week held in Cape Town September 5-7, Minister of Petroleum H.E. Gabriel Obiang Lima discussed drilling, investment, and regional cooperation.

Lima indicated that 2019 will be the year for drilling and investing, specifically investing in operations. Lima was clear that anyone not wanting to drill, "will not be allowed to work in Equatorial Guinea."

Lima has taken this stance and is of the opinion that he and his Ministry have been patient during the 2015-2017 period, where extensions were requested and granted. But times are different now and the current climate dictates a change. "The time to enforce the very basic formula whereby drilling results in discovery, and that discovery results in development," Lima stated passionately.

Petroleum Africa asked about the discovery announced in March by ExxonMobil, news having been scarce since that time. "The quantities were ok; they were sufficient, but it is not yet clear" what they will do with the resources with further analysis and study needed. He indicated the gas might be "re-injected to increase production," which suggests the discovery may be marginal.

When asked what the country's competitive advantage is over its nearby producing neighbors in attracting upstream investment, Lima said his Ministry is doing selective bid rounds, inviting companies to bid and negotiate for specific areas.

On investment, Lima was transparent in saying that currently the Chinese are the biggest investors, whether direct or indirect, and went on to say they are also the biggest consumers.

Source: Petroleum Africa/Antonette Benting

Gabriel Lima during Africa Oil & Power 2018

During a speech in March of this year at an Africa-focusd dinner at CERA Week in Houston, Lima stated "Equatorial Guinea will beat the US in supplying LNG to Africa." We asked him what has been achieved so far on this front, and what can we expect next?

"Equatorial Guinea has concluded a 15-year agreement with Ghana to supply LNG, as well as agreements with Togo and Sierra Leone," he said, reiterating that Equatorial Guinea "is committed to working with its neighbors in finding solutions that are mutually beneficial." Lima stated the country is also in discussions with Burkina Faso.

Further, Lima is highly optimistic that his country will become a regional oil and gas service hub. As an established and respected natural gas producer, Equatorial Guinea has the experience and know-how to cater to the industry in the greater region. At a press conference at this event, Lima said, "We want Equatorial Guinea to become a model and an example for other countries that are only just now starting their oil and gas industries."

President: Teodoro Obiang Nguema Mbasogo (August 1979)
Independence: October 1968 (from Spain)
Population: 778,358 (July 2017 est.)
GDP (purchasing power parity): $30.35 billion (2017 est.)
GDP - real growth rate: -4.4% (2017 est.)
GDP - per capita (PPP): $36,000 (2017 est.)
Minister of Petroleum and Energy: Béchir Madet

Oil - production: 124,000 bpd (September 2018 est.)
Oil - consumption: 5,200 bpd (2015 est.)
Oil - proved reserves: 1.1 billion barrels (2017)
Natural gas - production: 6.2 Bcm
Natural gas –consumption: 1.19 Bcm
Natural gas - proved reserves: 36.81 Bcm

Source: CIA FactBook, Organization of Petroleum Exporting Countries

Teodoro Obiang Nguema Mbasogo

EQUATORIAL GUINEA

Annual Petroleum Industry Updates

November 2017

Hess Corp sells its assets in Equatorial Guinea to Kosmos Energy and Trident Energy for a cash consideration of $650 million.

December 2017

ExxonMobil and GEPetrol make a discovery on Block EG-06 while drilling the Avestruz-1 well. As of March 2018 the two firms were continuing their assessment of the well's commerciality. ExxonMobil also recently entered Block EG-11, which is adjacent to Block EG-06.

April 2018

Equatorial Guinea becomes a force to be reckoned with in the region with its natural gas resources, through its LNG2Africa initiative. The country entered into a MoU with Togo to facilitate trade of natural gas between the two countries. The new MoU creates a framework for Togo to import LNG produced in Equatorial Guinea. The agreement is part of the LNG2Africa initiative, in which Equatorial Guinea is promoting the utilization of LNG within Africa, using gas sourced and processed in Africa. Togo will study the import, regasification of LNG, and its use for power generation.

May 2018

Marathon Oil signs Heads of Agreement with government and necessary third parties to establish framework for the processing of natural gas volumes through the Alba Plant's LPG processing plant and EG LNG's production facility, both located in Punta Europa. The existing processing facilities require only minor modifications to accommodate the third-party gas. New volumes from the third party are anticipated early in the next decade.

May 2018

Noble Energy is moving forward with the development of its Alen field natural gas resources, signing a Heads of Agreement with the government to that effect. The Alen field spans Noble's Blocks I and O. The resources from the Alen field will be processed at Marathon's Alba Plant LLC's LPG plant and EGLNG's LNG terminal. Sanction of the project is contingent upon final commercial agreements being executed. Noble Energy operates the Alen field with a 45% working interest and holds a 28% non-operated working interest in the Alba Plant.

May 2018

Ophir Energy entered into a farm-out agreement with Kosmos Energy for a stake in its EG-24 exploration license offshore Equatorial Guinea. Under the terms of the agreement, Kosmos will acquire a 40% non-operated interest in Block EG-24. In consideration for the stake Kosmos will fully carry Ophir for the cost of a block-wide 3D seismic survey during the first license period. In addition, Kosmos will partially carry Ophir for the cost of a well if the partners subsequently elect to drill a well in the second period of the license. Kosmos will also pay its pro-rata share of past costs.

June 2018

The Fortuna LNG development hit a bump in the road over the past year. Despite an agreed development plan and extensive efforts over the last 12 months by OneLNG and Ophir management, it has not been possible to finalize an attractive debt financing package. This, together with other capital and resource priorities, has resulted in a decision from Schlumberger to end its participation in the project. The announcement was made by Ophir and Golar who reported that, for Schlumberger, this withdrawal is due to repeated delays in making the project's FID. In the face of repeated postponements of the FID, the government of Equatorial Guinea has urged partners to find a solution by the end of this year. Otherwise, it would withdraw the operator status from Ophir or suspend the project.

July 2018

The Ministry of Mines and Hydrocarbons of Equatorial Guinea issued a mandate that all oil and gas operators in the country cease using CHC Helicopters. The Ministry told the firms to cancel all contracts with the transportation firm due to noncompliance with the country's national content regulations. According to the country's Minister of Mines and Hydrocarbons, Gabriel Mbaga Obiang Lima, CHC failed to comply with local content laws. Oil companies operating in Equatorial Guinea were given 60 days to unwind contracts and find new suppliers, with companies in compliance with the local content provisions established in 2014 allowed to bid for contracts.

July 2018

A compliance review of the entire sector is ongoing led by the Director of National Content and outside legal advisors of the Ministry. A compliance notice will be expanded to all service companies who are non-compliant as the review continues. Similar measures will be taken with those firms. Under the National Content Regulation of 2014, all agreements must have local content clauses and provisions for capacity building, with preference given to local companies in the award of service contracts. Local shareholders must be part of every contract as prescribed by law. The operators have an obligation to ensure compliance of their subcontractors.

September 2018

Equatorial Guinea's government launched the 2019 Year of Energy initiative, shining a light on new and innovative petroleum projects in Equatorial Guinea and assembling industry leaders at a series of energy-focused events. The objective of The Year of Energy is to further Equatorial Guinea's leadership role as an African energy capital, to showcase oil and gas projects, to promote its companies and accomplishments and to support the agenda of Africa's oil and gas countries. The initiative was opened officially in Malabo and was followed by an international launch at the Africa Oil & Power 2018 conference on September 5 in Cape Town.

September 2018

Minister Lima tells firms to drill or drop in an exclusive interview with *Petroleum Africa* (*see page 46*).

September 2018

Nigerian firm Oilserv Limited entered into a JV agreement with Equatorial Guinea's state-run oil and gas firm GEPetrol. The agreement with GEPetrol will aid Oilserv in expanding its footprint in the industry. The joint venture agreement resulted in the formation of Oilserv Equatorial Guinea.

By Luís Miranda
Miranda & Associados

Wind of Change in the Gabonese Hydrocarbons Sector?

Gabon is a central African country rich in natural resources. It is bordered by Cameroon and Equatorial Guinea to the north, the Republic of Congo to the east, and by the Atlantic Ocean to the west. With a population of and a surface area of around 268,000 sq km, Gabon is a sparsely populated country with forests covering 85% of the territory.

Gabon also possesses one of the highest urbanization rates in Africa, with more than four in five Gabonese citizens living in urban areas. The capital Libreville and the economic capital of the country Port-Gentil are home to 59% of the population. One in two Gabonese citizens is under the age of 20, and the fertility rate in urban areas stands at almost four children per woman, against six in rural areas, according to the 2012 Second Demographic and Health Survey conducted in Gabon.

Oil remains the lifeblood of Gabon's economy, representing half of the State's revenues and around 80% of its export earnings in 2014. The country benefits from relatively light, sweet crude from accessible onshore deposits, and has potential in deep offshore blocks. However, the absence of any recent major oil discoveries, declining production at mature fields and, above all, the halving of international oil prices over the past years have dampened the short-term outlook, leading to a push to aggressively increase enhanced oil recovery techniques and new exploration.

> "In an effort to stimulate its petroleum industry, Gabon announced it will soon complete a new comprehensive revision of its Hydrocarbons Code ... to create a more competitive and flexible environment for oil and gas investment."

The 2014 Hydrocarbons Law at a Glance

Gabon introduced a new Hydrocarbons Law in 2014 (Law no. 011/2014 of August 28). Under discussion since 2010, the law codified current contractual practice in the industry, with a move from royalty-based concessions to PSCs, and its main goal was to provide greater transparency in the industry. According to stakeholders, the new law provided a more structured framework for oil operators and was generally welcomed. However, some actors believed that setting a minimum threshold for fiscal terms would prove to be detrimental by making the oil and gas industry less attractive. In addition, promoting competition among financially and technologically capable operators would be, in their opinion, the best way to ensure balanced economic terms.

Compared to the 1962 and 1980s legislation, the new law created a far clearer legal framework for the oil and gas industry, while at the same time providing for new environmental protection standards, such as stricter limits on natural gas flaring. The law most notably defined five different types of contracts – exploration agreements, contracts for production and sharing of production, those for exploration and sharing of production, service contracts, and technical evaluation agreements – setting out the rights and obligations of the parties under each type of contract. In anticipation of the new legislation coming into force, many new PSCs were signed prior to the promulgation of the law for blocks awarded in the 2013 licensing round, as well as for existing producers. Subsequently, seven companies were awarded PSCs for nine blocks in autumn 2014, while numerous others were able to secure renewals of their agreements and licenses.

The new law also underlined Gabon's intent for the State to play a more direct role in the industry, expanding the scope of activity for the Gabon Oil Company (GOC). The State is now entitled to take up to 55% in any new production field, while also having the right to a free carry of 20% in every new PSC. GOC also has the right to purchase up to an additional 15% in a PSC at market rates, and the ability to acquire at market rates a maximum participating interest of 20% in the equity of any company applying for or holding an exploitation title.

In addition to carving out a larger share of operations, the State can now see increased benefits from a new fiscal and revenue-sharing regime applicable to PSCs laid out in the 2014 law. Corporate tax remained at 35%, in line with the general tax rate, though it is no longer included in the State's share of profit oil, thus affecting project profitability for the IOCs. However, the law also incorporated a measure of flexibility: four of the seven fiscal rules were open to negotiation and were determined at the time of PSC signing, including signature and renewal bonuses, cost recovery and profit oil, and calculation of proportional royalties. Profit oil is shared on a sliding scale basis, with a minimum share for the State in the first tranche of no less than 55% in conventional oil and 50% in deep offshore, on par with other regional oil producers. Cost recovery petroleum has now also been limited to 65% for conventional fields and 75% for deep offshore.

The Current Local Content Requirements

As governments look for ways to elevate local capacity and bolster economic development, finding the right balance in local content policies and programs can incentivize financial investment and technical and technological transfers that will benefit countries competing to attract the best companies, as well as companies searching for the most attractive markets to maximize efficiencies and manage costs. Pressure to use local content (e.g. local workers, companies, goods, and services) in large or mega-projects continues to increase throughout the developing world. For growing markets, particularly in Africa, if adequately managed it can be a catalyst for rapid development.

As is the case in many of Africa's hydrocarbons producers, the Gabonese government is also seeking to support the development of local small- and medium-sized enterprises providing services to multinationals in the oil and gas industry, as well as increasing the employment and training of nationals. The 2014 Hydrocarbons Law reasserts principles of existing national labor legislation in terms of priority employment for nationals with equivalent skills and qualifications, as well as the prioritization of local subcontractors. As a result, the government and foreign oil operators have a common interest in ensuring that there is a qualified local workforce if they are to meet local hiring quotas. The truth is that while currently oil firms' workforces should be at least 90% made up of locals, this quota can rarely be met due to a lack of qualified or specialized workers.

Due to this difference between policy and statutory requirements and local workforce availability, there has been a push to increase training and education capacity. Foreign oil producers such as Total, Shell and Perenco joined forces with the government to create the Oil and Gas Institute, located in Port-Gentil, which received formal recognition in June 2014. A course in petroleum engineering by France's IFP Training, including five-month internships, was also launched in March 2014. In addition, Total also provided funding to the "*École Polytechnique de Masuku*" in Franceville, to offer a Master's degree in petroleum engineering, while Addax sponsored engineering students and provided funding for equipment at the same school under a partnership formed in May 2014.

The Need of a New Legal Framework for the Gabonese Oil Sector

Gabon is among the top five oil producers in sub-Saharan Africa and has been an oil producer for more than 50 years. It reached its peak 12 years ago when oil production hit 370,000 barrels per day (bpd) and has been declining since to its current level of 200,000 bpd. To combat the natural decline of mature fields, the government has focused on offshore resources, which account for more than 70% of the reserves. Like other oil-dominated economies of the Economic Community of Central African States' single-currency zone, Gabon has struggled due to the decline in crude oil prices, forcing it to seek support from the International Monetary Fund in 2017.

In an effort to stimulate its petroleum industry, Gabon announced it will soon complete a new comprehensive revision of its Hydrocarbons Code. In a special event hosted by the Ministry of Petroleum and Hydrocarbons in Libreville in March this year, Gabon declared its willingness to create a more competitive and flexible environment for oil and gas investment. Among other discrepancies with the current business climate, the existing fiscal regime was designed for an oil barrel price of over $100 and should now be amended to reflect realistic market conditions. According to Mr. Pascal Houangni Ambouroué, the current Minister of Petroleum and Hydrocarbons, the government's short term political strategy is to bring Gabon to global standards of excellence for operating in the oil and gas industry.

During the event, the Ministry also had the opportunity to hold several seminars to gather input from industry stakeholders on how to optimize the impact of the Hydrocarbons Code revision. The event also included the participation of OPEC and government delegations from Equatorial Guinea and the Republic of Congo. The Gabonese government expressly emphasized the need to create a new investment framework enabling immediate increases in production and new oil and gas exploration. Additionally, one of the key revisions to the code is expected to establish highly anticipated regulations for gas industrialization and monetization. For the first time, natural gas will also be recognized as a resource equal to oil, with provisions on the exploitation of discovered reserves and a reduction of gas flaring to the bare minimum.

Conclusion

Efforts to renew Gabon's flagging hydrocarbons code began four years ago, spurred by a climate of plummeting oil prices and dwindling exploration activity. A sustained industry downturn prompted heavy consolidation among industry players, with Perenco, for instance, acquiring several producing legacy assets from Total in 2017, for $350 million. Not long after, Shell sold all of its onshore acreage in Gabon to Carlyle Group, which spun off the acquisition into Assala Energy. This consolidation may help to revamp the sector.

The revitalization of the sector is being welcomed by well-established oil and gas companies in the country, which had previously mentioned that a decline in commodity prices had rendered Gabon's fiscal regime outdated and perhaps hindered the country's new investment prospects. The new code is expected to make Gabon more competitive in the international investment domain and to also create the necessary conditions to replace oil production through new discoveries while at the same time sustaining current production levels.

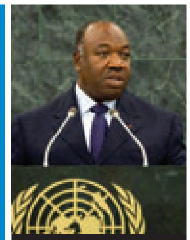
About the Author

Luís Miranda is currently the Head of Miranda Alliance's Houston Liaison Office. Prior to moving to Houston, Luís gained significant experience advising oil companies and living in West Africa, including in Gabon, where he was based at Miranda's local office. Luís may be contacted at Luis.Miranda@mirandalawfirm.com.

President: Ali Bongo (October 2009)
Independence: August 1960 (from France)
Population: 2,119,036 (July 2018 est.)
GDP (purchasing power parity): $36.66 billion (2017 est.)
GDP - real growth rate: -0.5% (2017 est.)
GDP - per capita (PPP): $18,100 (2017 est.)
Oil Minister: Pascal Ambouroue

Oil - production: 187,000 bpd (September 2018 est.)
Oil - consumption: 22,000 bpd (2015 est.)
Oil - proved reserves: 2 billion barrels (2017)
Natural gas - production: 378 Mmcm
Natural gas – consumption: 378 Mmcm
Natural gas - proved reserves: 28.32 Bcm

Source: CIA FactBook, Organization of Petroleum Exporting Countries



Ali Bongo

GABON

Annual Petroleum Industry Updates

November 2017

Shell, through its affiliates, completed the sale of its entire onshore oil and gas interests in Gabon to Assala Energy Holdings Ltd., a portfolio company of The Carlyle Group. Assala paid a total of $628 million including equivalent interest for the assets. The transaction consisted of all of Shell's onshore oil and gas operations and related infrastructure in Gabon: five operated fields (Rabi, Toucan/Robin, Gamba/Ivinga, Koula/Damier, and Bende/ M'Bassou /Totou), participation interest in four non-operated fields (Atora, Avocette, Coucal, and Tsiengui West), as well as the associated infrastructure of the onshore pipeline system from Rabi to Gamba and the Gamba Southern export terminal. Shell onshore in Gabon produced approximately 41,000 boepd in 2016. Shell Trading (STASCO) will continue to have lifting rights from the Gabon onshore assets for the coming five years.

January 2018

Spectrum, in cooperation with Gabon's Direction Generale des Hydrocarbures (DGH), launched its next phase of multi-client seismic acquisition. The company acquired a shallow water 3D campaign offshore northern Gabon. The campaign was focused on acquiring seismic programs in under-explored shallow water open blocks with the objective of offering the most up-to-date 3D imaging of the area. The DGH intends to make these blocks available through future shallow water license rounds so as to accelerate exploration. This data will facilitate immediate activity when the blocks are awarded.

January 2018

Gabon's Ministry of Oil signed seven oil contracts with six companies as a result of its offshore licensing round in 2017. The country's licensing round was expected to attract at least $1.1 billion in investment to the sector. Woodside Petroleum and Noble Energy were just two of the winners, acquiring stakes in Block F15. The PSC includes a four-year seismic commitment and a future option for exploration drilling. Woodside CEO Peter Coleman said the EEPSC was an opportunity for Woodside to secure significant acreage in a high graded emerging oil-prone province with a like-minded and experienced partner.

January 2018

Panoro Energy commenced drilling the offshore DTM-2H production well on the Tortue oil field. The field is part of the Dussafu Marin PSC. The well was drilled with the *Borr Norve* jack-up rig. The DTM-2H well was drilled as a horizontal well targeting the Dentale D6 reservoir at 3,140 meters true vertical depth subsea. Following drilling, the DTM-2H was to be completed as a gas lifted, subsea oil production well with an approximate 500-meter horizontal drain.

March 2018

PC Gabon Upstream SA (PCGUSA), a subsidiary of Malaysian firm Petronas, made a new discovery offshore Gabon. The company drilled an oil and gas discovery on Block F14 (Likuale), located in the south of Gabon. The Boudji-1 exploration well encountered both oil and gas while drilling. The ultra-deepwater exploration well, drilled in water depths of 2,800 meters, encountered 90 meters of gross high-quality hydrocarbon-bearing pre-salt sands.

March 2018	Gabon is revising its 2014 hydrocarbons laws as a way to attract new investment into the petroleum sector, according to a statement from the Ministry of Oil. The law from 2014 was based on a much higher per barrel price than today's current market prices. Under the current legal framework, the Gabonese state holds a minimum 20% stake in oil projects. The state oil company has the right to a stake of up to 15%. The Ministry said that a panel of legal, economic and tax experts will come together to look at changes to the law.
April 2018	Repsol made a discovery while drilling in Gabon. The company encountered oil while drilling the Ivela-1 exploration well offshore the West African country. Repsol started drilling the Ivela-1 well at the end of January 2018 using the Seadrill-owned *West Capella* drillship. Woodside reported that the well intersected a 78-meter gross oil column and the assessment was ongoing. The well was completed during Q1.
April 2018	Total and Vantage Drilling International entered a contract that will see one of Vantage's jack-up rigs working offshore Gabon. The contract with the subsidiary, Total Gabon, is for use of the *Topaz Driller* to perform drilling services on Total's offshore acreage.
May 2018	Panoro Energy's DTM-3 appraisal well offshore Gabon was successfully drilled. The DTM-3 appraisal well, located within the Dussafu License's Tortue field, was designed to appraise the western flank of the Tortue Field, attempting to extend the known distribution of hydrocarbon resources within the Gamba and Dentale formations. As planned, the well was plugged and abandoned.
June 2018	VAALCO Energy's workover operation on Gabon's South Tchibala 1 HB well was completed, as was the replacement of the Electrical Submersible Pump (ESP) system. The ESP system replacement was conducted safely and efficiently with no injuries or environmental incidents. The well is producing at approximately 990 bpd of oil gross. Further, workover operations to replace the ESP system in the Avouma 2H well and restore approximately 2,000 bpd of production took place.
June 2018	BW Offshore and Panoro Energy saw the successful drilling and completion of their second development well, the DTM-3H. The drilling of DTM-3H well commenced in May and was successfully completed with no safety-related incidents, on schedule and within budget. According to Panoro, the interpretation of the logging results indicated that the well was entirely consistent with pre-drill prognosis and objectives. DTM-3H was drilled and completed as a horizontal production well in the Gamba reservoir where it encountered a long horizontal section of oil saturated Gamba sandstone as prognosed. The well was suspended pending arrival and hook up to the FPSO in Q3. The FPSO left Singapore in June.
August 2018	Total Gabon sold its stake in the Rabi-Kounga field. The company held a 32.9% stake in the field that is located onshore in the southern region of Gabon. According to reports, the stake was purchased by Assala Upstream Gabon for an estimated $100 million. The disposal of the stake is part of Total's plans to simplify its portfolio.
September 2018	BW Offshore achieved first oil from the offshore Dussafu license on the Tortue field through the *BW Adolo FPSO*. First oil was achieved just 18 months after the initial investment was made.
September 2018	BW Offshore successfully drilled and completed its Ruche North East (DRNEM-1) appraisal well. The well, located on the Dussafu License, encountered oil on the Ruche North East structure. The DRNEM-1 well encountered 40 meters of pay in the Gamba and Dentale formations in the original wellbore. An appraisal side-track was drilled approximately 800 meters north-west of the original wellbore and encountered 34 meters of pay in the Gamba and Dentale formation. The technical and commercial teams are performing an evaluation of the potential development of these resources. The well completed the partners drilling on the Dussafu for 2018.
October 2018	Gabon launched its highly-anticipated 12th Shallow and Deep Water Licensing Round for open blocks in November. The opening of the licensing round took place at the 25th Africa Oil Week held in Cape Town early November. Pascal Houangni Ambouroue, Minister of Oil and Hydrocarbons, made the announcement during a special session on November 7. The announcement was followed by a technical and fiscal workshop that will detail the new petroleum code, the license round and associated terms. The agenda included further details of available blocks, the fiscal terms, timings and conditions of the 12th Gabon Licensing Round.

By Ana Pinelas Pinto and Hugo Moreira
Miranda & Associados

REPUBLIC OF CONGO

SLOWLY BUT SURELY REVERSING OIL PRODUCTION DECLINE

The Republic of Congo is one of Africa's mature oil producers and has been in play since the 1960s. Oil reserves are estimated to be as high as three billion barrels, and despite the trend that we have been witnessing of declining oil production, output has increased in recent years. This is largely thanks to Total's Moho Nord deep offshore project being brought on stream in early 2017. The project's output is expected to reach 350,000 bpd this year, making the country the third largest oil producer in sub-Saharan Africa behind Nigeria and Angola. The Congo's economy is deeply oil-dependent, with the oil sector accounting for about 65% of the GDP, 85% of government revenue, and more than 90% of exports.

2016 was looked at with great anticipation. Early that year the President was reelected, without significant political instability or civil turmoil, and putting an end to the lethargy that is typical in pre-election periods. A new Hydrocarbons Code was enacted to repeal the outdated predecessor that had been in force more than 20 years, and a licensing round was launched with eight offshore blocks in deep and ultra-deep waters, along with five onshore blocks being put on offer. In part, these efforts were aimed at attracting newcomers to the Congolese oil industry, and to a limited extent the Congo was successful in doing so. However, the expectations that were created and the momentum that began to be gained did not entirely yield the results that had been anticipated.

Realizing this, the Congo is stepping up to its continued challenges, has become since June 2018 the fifteenth member of OPEC (and the seventh African nation to join the oil cartel), is in talks with the IMF over a financial assistance program, promoted the then-incumbent CFO of Société Nationale des Pétroles du Congo (SNPC, the Congolese NOC) to CEO, appointed a new General Director of Hydrocarbons (who spent her entire career in the sector, working for private companies), and is preparing a draft Gas Code to streamline the legal and tax framework of its gas value chain.

Within the ongoing challenges, Congo has also just launched the second stage of the 2016 licensing round. The 2016 Hydrocarbons Code will be the backdrop of the licensing round and June 30, 2019 has been slated as the deadline for the submission of offers. The terms of reference for each of the 18 blocks put on offer are already available (5 onshore blocks in the Cuvette Basin, 3 onshore blocks in the Coastal Basin, 5 offshore blocks in shallow waters, and another 5 offshore blocks in deep and ultra-deep waters). According to well-informed sources, an encouraging number of formal expressions of interest have already been tendered – including by international players looking at investing in the Republic of Congo for the first time.

Ideally, these efforts would also include the preparation and enactment of the long-awaited regulations of the Hydrocarbons Code, which left a significant number of critically important issues to be addressed in ancillary statutes, such as the payment and management of the funds for abandonment and restoration, local content, and the tax and customs regime.

Pending such regulations, here is a snapshot of the features of the framework instituted by the 2016 Hydrocarbons Code which may be deemed the most significant for those contemplating investing in the Congolese oil industry (or just seeking more in-depth information on the currently-applicable legal regime):

- SNPC is the exclusive concessionaire of petroleum mineral titles – in the form of exploration permits or production permits, granted by the Council of Ministers upon proposal of the Minister of Hydrocarbons – meaning that IOCs and private Congolese petroleum companies will have to associate themselves with SNPC to conduct petroleum operations. A minimum participating interest of 15% is reserved by law to SNPC, which is 'carried' by the other members of the contracting group of companies;

- Petroleum contracts have to be either a PSC or a services agreement, whose models are approved by the Council of Ministers;

- As a condition for their effectiveness, petroleum contracts negotiated and signed with a contracting group of companies must be submitted to the approval of both chambers of Parliament;

- While for the exploration phase the operator is authorized to merely register a branch in the Congo, it will be required to incorporate a local company for the production phase;

- Any provisions in the petroleum contracts found to be in contravention with the Hydrocarbons Code are deemed to be null and void;

- Unless otherwise authorized by the Minister of Hydrocarbons, a minimum participating interest of 15% in the contracting group of companies (which can rise up to 25% in certain cases) is reserved for private Congolese petroleum companies. This participating interest is in addition to that reserved for SNPC, but unlike the latter it is not carried;

- In terms of fiscal and para-fiscal charges, the Hydrocarbons Code provides that, in respect of the PSCs to be entered into there under, a 15% royalty shall apply on oil net production and a 5% royalty shall apply on gas net production (the former may, in the case of production in waters deeper than 500 meters, be reduced to 12%). As for the maximum cap for cost oil, it is 50% of net production, although in specific situations (e.g. deep-water projects or recourse to very expensive technology) said cap may be raised up to 70%. Also worth mentioning is that the State's minimum share in the profit oil for each calendar year will be 35%. As to the income tax rate, it may be set in the petroleum contract within the limits defined in the General Tax Code;

> "Congo has also just launched the second stage of the 2016 licensing round. The 2016 Hydrocarbons Code will be the backdrop of the licensing round and June 30, 2019 has been slated as the deadline for the submission of offers."

- Each member of the contracting group of companies is to provide a corporate guarantee by the ultimate parent company, or a first demand bank guarantee, in favor of the State, covering the minimum work obligations for exploration, which is to be provided under such conditions and within such deadlines as are to be defined in a Decree of the Council of Ministers;

- With certain operational exceptions being allowed in accordance with best industry practice, and unless otherwise permitted by prior special authorization of the Minister of Hydrocarbons, flaring of associated gas is prohibited; and

- A provision for abandonment must be made pursuant to an abandonment plan, with the abandonment funds so collected being deposited in an escrow account with the *Caisse des Dépôts et Consignations*.

Ravaged by a dip in prices and production since 2014, the Congo has managed to buck the trend and is set to become the third biggest oil producer in sub-Saharan Africa this year, with the new developments in progress expected to further boost production to 400,000 bpd by 2020. To a significant extent, this has been backed by Total's and ENI's flagship projects, two companies which the Congolese authorities label as historic partners and whose bearing on the local marketing is not expected to change anytime soon. Still, and especially owing to the country's recent accession to OPEC, the Congo is keen on liberalizing the sector and on bringing in new players, in particular those interested in investing in marginal fields.

These are all encouraging indications that the Congo is heading the right way. Slowly, some might say, but surely.

About the Authors

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US Cities Commit to 100% Renewable Energy

Despite US President Donald Trump pulling out of the global climate accords last year, the North American country continues to contribute to reducing its greenhouse gas emissions and helping to mitigate climate change. Many of its 50 states maintain strong, clean energy legislation and goals, and their cities are also embracing their own unique programs.

The Ohio city of Cleveland, also known as "the heart of rock n roll," announced its latest plan to deal with climate change during the 10th Sustainability Summit. As part of the city's goal to reduce greenhouse gases, Cleveland's Chief of Sustainability Matt Gray announced the city's goal to reach 100% clean renewable energy by 2050.

"When we say that, that's everything," Gray said. "That's what residents are using, that's what businesses are using – industry, government, the whole city." Gray said to reach the goal, the city would turn to solar and wind energy plus encourage energy efficiency in businesses and homes.

The city's climate action plan notes progress made in sustainability efforts since the first action plan in 2013, including a two percent decrease in greenhouse gas emissions in 2016 from 2010 levels.

Cleveland is not alone; 82 other US cities have already made a similar pledge. It was recently announced that the country's capital city, Washington D.C., would make the move toward 100% renewable energy. Washington, D.C.'s city councilors are likely to pass the most aggressive renewable energy mandate in the country, calling for 100% renewables in just 14 years.

The "Clean Energy DC Act of 2018," legislation sponsored by five D.C. city councilors and co-sponsored by another three, calls for the nation's capital to have 100% of its grid be powered by wind, solar and other renewable energy by 2032. The city's current standard is only 50% renewables by 2032. If passed, the bill would be the most ardent clean energy mandate in the country, according to a report by the Daily Caller.

US cities that have already achieved 100% renewable-powered status include Aspen, Colorado; Burlington, Vermont; Greensburg, Kansas; Rock Port, Missouri; Kodiak Island, Alaska; and perhaps surprisingly, Georgetown, located in the pro-oil state of Texas.

Dozens more cities and counties have made the commitment and are working to achieve 100% renewable status according to their individual self-imposed mandates.

Facebook Commits to 100% RE by 2020

Facebook has committed to power its global operations with 100% renewables and reduce its greenhouse-gas emissions 75% by the end of the decade. Given that the company hit its previous renewable energy goal one year early, 100% by 2020 should be an achievable goal for the company.

In 2015 Facebook set a goal of supporting 50% of its facilities with renewables by 2018. The company has achieved that goal a year early, reaching 51% clean and renewable energy in 2017.

The company's goal follows others in the tech industry like Google and Apple, both of these company's achieved 100% renewable energies used in 2017 and 2018 respectively.

At this time Facebook is on track to be one of the largest corporate buyers of renewable energy in 2018, a year when companies have signed deals for record amounts of clean power.

Since its first purchase of wind power in 2013, Facebook has signed contracts for over 3 GW of new wind and solar energy, that includes over 2,500 MW in just the past 12 months.

"We are proud of the impact our renewable energy program is having on local communities and the market in general. All of these wind and solar projects are new and on the same grid as our data centers. That means that each of these projects brings jobs, investment and a healthier environment to the communities that host us — from Prineville, Oregon, and Los Lunas, New Mexico, to Henrico, Virginia, and Luleå, Sweden," the company said in a statement.

AfDB Offers Up $1.5 Mil for Ghana's RE

A grant from the AfDB for $1.5 million to Ghana will aid the country in removing barriers to investment in the renewable energy efficiency sector. Akinwumi Ayodeji Adesina, the President of the bank said Ghana was showing the way towards universal access to energy.

Ghana has one of the highest access to energy rates due to its utilization of off-grid solutions. Adesina made the remarks in a speech read on his behalf at the opening of the Fourth Ghana Renewable Energy Fair in Accra, on the theme: "Renewable Energy: Exploiting Energy Resources at the District Level."

Adesina said energy efficiency was one of the key solutions for climate change, adding that the AfDB had identified some African countries, which it was supporting to establish energy regulatory frameworks to attract private investment into the sector.

Vestas Turbines Destined for Enel's South African Wind Farms

Vestas Wind Systems, under contract to Enel Green Power, will install two wind farms with a combined capacity of 294 MW in South Africa. According to the agreement signed, Vestas will install 70 units of its V136 turbines, each capable of producing 4.2 MW to power the Karusa and Soetwater plants with 147 MW of individual capacity.

Source: Enel Green Power

The towers that will be used for infrastructure construction will come from the local market. All turbines are expected to be delivered and installed by H2 2020. The two plants are scheduled to enter service by H2 2021.

Under the terms of the contract signed between the two companies, Vestas will provide after-sales services for a period of five years.

The Karusa and Soetwater plants are part of a batch of five wind power plants that Enel has been building in the country. The other infrastructures are the Garob, Oyster Bay and Nxuba plants. The independent power producer recently raised $1 billion for their construction.

DRC Signs Joint Deal for Inga 3

The Democratic Republic of Congo (DRC) is moving forward with its Inga 3 hydroelectric project. DRC is said to have signed a joint deal on October 16 to develop the $14 billion hydroelectric project with one consortium led by China Three Gorges Corp. and a second led by Spain's ACS (Actividades de Construccion y Servicios SA).

The Inga 3 project has repeatedly been delayed by red tape and disagreements between the government and its partners. ACS and China Three Gorges were initially competitors for the project until the DRC asked them to submit a joint bid.

The next stage requires the investors to carry out detailed studies for the project, taking into account social and environmental considerations, the state agency responsible for the project said in a statement.

The 11,000-MW Inga 3 will not only be used domestically, but there is a good possibility that power produced could be exported to South Africa adding another income stream for DRC.

Under the high patronage of HE Faure Essozimna Gnassingbé, President of the Togolese Republic; the Minister of Mines and Energy, Marc Dèdèriwè Ably-Bidamon; and the Director General of the pan-African industrial group Eranove, Marc Albérola, signed a power generation concession agreement for the design, financing, construction, commissioning, operation and maintenance of the Kékéli Efficient Power plant, which will be located in the Lomé port area.

This project follows a competitive dialogue launched in January 2018. It includes the participation of Siemens, which wishes to be actively involved in the electrification efforts of the Togolese Republic, and will provide the turbines, technology and maintenance services for the power plant. The construction will be carried out by the Spanish group Grupo TSK (EPC). As for the financing to be mobilized in CFA francs, the West African Development Bank (BOAD) and the pan-African banking group Oragroup will be the lead partners. The Eranove group will develop, operate and maintain this plant, which will eventually be operated and managed by Togolese people.

With an installed capacity of 65 MW, the Kékéli Efficient Power gas plant will use combined cycle technology. The technology makes it possible to produce more electricity without extra gas consumption while limiting CO_2 emissions into the atmosphere, thereby contributing to electricity production that respects the sector's economic and financial balance and the environment.

Sierra Leone to Add 50 MW Through Solar

Sierra Leone secured $40 million in financing from the IFC, a member of the World Bank Group, for the construction of a solar power plant. The solar plant will have a 50 MW capacity and construction is expected to take between 18 and 24 months.

The energy generated will be transferred to the national grid at a cost of 8 cents per kilowatt hour.

The implementation of this project will aid in expanding Sierra Leone's relatively small electricity grid. Sierra Leone has an installed capacity of less than 150 MW, for an electrification rate of 12%.

The country is currently developing a project to expand its electricity grid through the construction of substations and transmission infrastructure. The cost of this project has been estimated at $78 million.

Alten Africa Seeking Partners for Nigerian Solar

In Nigeria Alten Africa is seeking partners for the engineering, equipment, construction and operation of the 100 MW Kogisolar power plant. Companies had until October 26 to submit their commitment and interest in the project.

The project covered by the call for expressions of interest will be located in Nigeria's Kogi State. The energy it will produce once up and running will be transferred to the national grid under a power purchase agreement.

The project as a whole is being developed by Alten Africa, a subsidiary of the independent Italian energy producer, Alten Energias Renovables. Nigerian firm Middle Band Solar One Limited (MBSO) is also associated with the project.

Alten Africa is currently developing a 45-MW solar power plant in Namibia and a 52-MW solar power plant in Kenya.

Clair Ridge Sees First Oil

BP and its co-venturers Shell, Chevron and ConocoPhillips, saw first oil production from the giant Clair Ridge project in the West of Shetland region offshore UK. Clair Ridge is the second phase of development of the Clair field. The field, which was discovered in 1977, has an estimated seven billion barrels of hydrocarbons.

Two new, bridge-linked platforms and oil and gas export pipelines have been constructed as part of the Clair Ridge project. The new facilities, which required capital investment in excess of £4.5 billion, are designed for 40 years of production. The project has been designed to recover an estimated 640 million barrels of oil with production expected to ramp up to a peak at plateau level of 120,000 bpd.

Source: BP

Clair Ridge is the first offshore deployment of BP's enhanced oil recovery technology, LoSal®, which has the potential to increase oil recovery from reservoirs by using reduced salinity water in water injection. This is expected to result in up to 40 million additional barrels being cost-effectively recovered over the lifetime of the development.

Faroe Starts Drilling Brasse East

Faroe Petroleum saw the commencement of the Faroe-operated Brasse East exploration well 31/7-3S in the Northern North Sea. The Brasse East well is being drilled immediately east of the Brasse field (discovered by Faroe in 2016 and appraised in 2017) which in turn is located to the south of the Brage field and to the south east of the Oseberg field.

At the end of 2017, the Brasse field development feasibility study phase was completed, confirming several economically attractive development solutions and export routes. Concept studies are currently progressing according to plan. The co-venturer in the Brasse PL 740/PL 740 B/PL 740C licenses is Point Resources AS (50%).

The total expected vertical depth of the well is approximately 2,271 meters, in a water depth of 124 meters. Drilling operations will be undertaken using the semi-submersible *Transocean Arctic* rig. The results will be announced on completion of drilling operations.

Tonalli Energia Awards Mexico's Block 24 Contract

SIMMONS EDECO was awarded a contract by Tonalli Energia S.A.P.I. de C.V to provide drilling services in Mexico. The contract, which has already begun, engages the company in supporting Tonalli's onshore oil and gas development Block 24.

The Block known as Tecolutla, is in the Tampico-Misantla Basin in the Mexican state of Veracruz. SIMMONS EDECO will drill the horizontal well 2310 TVD to a measured depth of 3,750 meters using Rig 836, which recently drilled a number of wells on the Amatitlan block in Mexico.

Although SIMMONS EDECO has been providing onshore drilling services in Mexico since 2015, this drilling project represents the first time that the company will have worked on behalf of Tonalli Energia, a JV between Mexican petrochemical company Grupo IDESA and Canadian oil and gas company International Frontier Resources.

TechnipFMC Signs Surface Technologies Frame Agreement

TechnipFMC signed a Surface Technologies Frame Agreement with Chevron. This five-year agreement covers the exclusive supply of surface wellhead equipment and service in the United States and Canada.

Richard Alabaster, President of TechnipFMC's Surface Technologies business, commented: "We are very pleased to extend our partnership with Chevron and to support their development program in North America. We believe that this reflects the strong collaboration we have developed with this major shale operator, based on the demonstrated value of our integrated drilling and completion offering."

BiSN Celebrates Multiple Firsts

BiSN celebrated multiple ground-breaking firsts for the business. Working with various new clients, BiSN has expanded its marketplace, deploying tools in three new regional locations, including the Denver-Julesburg basin in Colorado, Australia and Algeria.

BiSN recently deployed the largest bismuth plug in the Valhall A-30 well, Norway, in conjunction with Aker BP and Altus Intervention. The trial involved using 3,500 kg of bismuth alloy to create a gas tight seal.

In addition, an Algerian project was of particular significance to the company, as it was also the highest downhole temperature – 150 degrees centigrade – that its Wel-lok M2M technology has been deployed in to date.

These achievements follow an already successful year for the company, following multiple award wins, and a major double first when deploying the first tool setting on telecoil while utilizing their unique tubing seal, Wel-lok M2M TS™ EXD, in Azerbaijan.

Unique and Innovo Complete Job for Saipem in ME

Unique Group together with Innovo successfully completed a multi-million dollar decommissioning contract for Saipem on a key offshore platform in the Middle East region. Unique Group and Innovo team members worked together to meet the project's requirements of providing bespoke equipment which helped reduce operating times and ensured cost effectiveness of the project within a very tight delivery schedule.

Source: Cutting Spread

The team with their specialist knowledge helped with the design, manufacturing and delivery of the equipment in less than four months. This fast and efficient turnaround considerably helped Saipem to meet the operator's deadline for kick-off operations, with the first step of the campaign completed safely and ahead of schedule.

Internal and external dredging tools, diamond wire cutting tools and internal cutting tools based on abrasive water jet technology, operating at 1,500 bar, were provided for the project along with skilled operators to support the operation.

DeltaTek Global Celebrates Inaugural Deployment of SeaCure

DeltaTek Global announced the inaugural deployment of its SeaCure technology. The work scope for Chevron North Sea took place on the West Wick subsea appraisal well which is being drilled from the *Ocean Guardian*.

Providing major time and cost savings, the pioneering SeaCure cementing system delivers stabbed-in, inner string cementing for subsea wells and was deployed to cement a 30" conductor casing. With no shoe track present, SeaCure eliminated the need to perform a dedicated clean out run prior to drilling commencing with a 12-1/4" Bottom Hole Assembly (BHA) straight out of the 30" float shoe.

The project is a continuation of SeaCure's successful field trials completed earlier this year which were also supported by the Oil & Gas Technology Center.

Big Foot Comes Onstream

First oil and gas production from the Chevron-operated Big Foot deepwater project in the GoM has begun. The field is located approximately 225 miles south of New Orleans, Louisiana in a water depth of approximately 5,200 ft.

The Big Foot project uses a 15-slot drilling and production tension-leg platform, the deepest of its kind in the world, and is designed for a capacity of 75,000 barrels of oil and 25 Mmcf/d of natural gas.

Source: Chevron

The Big Foot field is estimated to contain total recoverable resources of more than 200 mboe and has a projected production life of 35 years.

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

Elevated Gas Readings on Paus Biru-1

Cue Energy Resources, as a JV partner on the Sampang PSC, revealed that elevated gas readings were encountered with the drilling of the Paus Biru-1 exploration well offshore Indonesia.

The well reached TD of 710 meters. The planned TD was extended during drilling due to formation observations. Elevated gas readings were encountered through the Primary target Mundu Formation.

Following preliminary interpretation of the logging while drilling, a full suite of wireline logs including formation wireline testing, which obtains formation pressures and fluid samples, will be run to further assess the interval. Data obtained will help establish the fluid content, hydrocarbon columns and hydrocarbon saturation of possible reservoir intervals encountered.

HydraWell Completes Decommissioning for TAQA

HydraWell completed an offshore decommissioning project for TAQA in the Netherlands. The plugging job was conducted at one of the fields connected to the TAQA-operated P15 platform, situated approximately 35 km north-west of Hoek of Holland. The dual casing Perf, Wash and Cement job was conducted from the *Maersk Resolute*. HydraWell's contract value is undisclosed.

To execute the project, HydraWell utilized its Hydra Hemera™ Perf, Wash and Cement (PWC®) jetting system, which can install a rock-to-rock barrier in two days. In comparison, plugging offshore wells with conventional methods, such as section milling, can often take 10-14 days to complete. The latter drives the associated decommissioning costs up significantly. To date, 16 operators – including major, national and independent oil companies – have utilized the PWC® technology, installing more than 250 plugs worldwide.

Israel Launches Second Bid Round

Israel launched its second bid round for oil and gas exploration license round in its economic waters in the Eastern Mediterranean. The upcoming bid round is pursuant to an earlier round which began two years ago and granted six licenses, some are expected to commence drilling in the upcoming months.

In the new bid round, licenses for 19 blocks will be issued in five zones. Each block measures up to 400 sq km and each zone, consisting of multiple blocks, can be as large as 1,600 sq km. The decision to market the blocks in zones is to allow better correlation between the exploration areas and subsurface geological structures that potentially contain oil and gas reservoirs. Holding larger interests will allow efficient subsurface evaluation and will increase the attractiveness of the zones to investors.

The zones are located in the southern extent of Israel's economic waters, an area which has been previously licensed in part and had previous seismic research and limited exploration activity. The existing research indicates the potential for the discovery of hydrocarbons in the bid round area.

To broaden the participation of as many new bidders as possible in the bid round, the Israeli Energy Ministry has decided to limit the number of licenses granted to any one party to eight licenses.

In addition, it has been decided that any licensee holding over 20% of a producing oil lease - will not be able to participate in the current bid round. In addition, a group that does not hold current licenses will be preferred in the current bid round in order to increase diversity of license holders.

Licenses will only be granted in areas approximately four miles or greater from the shoreline, according to the strategic environmental survey conducted. While granting exploration licenses and approving surveys, drilling and infrastructure, the Ministry of Energy will inform the licensees regarding habitats in the license areas, the potential impacts on the level of development that will be allowed, the precautions that will be needed and the restrictions regarding the preservation of these habitats.

Companies who are interested in participating in the bid round and submitting proposals will be requested to enroll in the bid process and purchase a data package to include geological and geophysical data from drilling and 2D and 3D seismic surveys. Submissions are due by June 2019.

Union Jack Signs Farm-in

Union Jack Oil signed a farm-in agreement with Rathlin Energy (UK) for a 16.665% license interest in PEDL 183. PEDL 183 is located onshore UK in East Yorkshire and within the Western sector of the Southern Zechstein Basin and contains the significant West Newton A-1 gas discovery, where the drill-ready West Newton conventional appraisal well is planned to be drilled in Q1 2019.

The drilling of the material West Newton conventional appraisal well, where success is expected to deliver a significant onshore gas development project, will be transformational for Union Jack, according to the company.

On completion of this farm-in, Union Jack can book immediately 5.3 mboe Contingent Resources to its existing reserve and resource portfolio and once a Field Development Plan is in place, West Newton's Contingent Resources can be converted to Reserves.

Abu Dhabi's SPC Approves ADNOC's Gas Strategy

Abu Dhabi's Supreme Petroleum Council (SPC) has approved the Abu Dhabi National Oil Company's (ADNOC) new integrated gas strategy and plans to increase its oil production capacity to 4 million bpd at the end of 2020 and 5 million bpd by 2030.

The SPC's approval of ADNOC's gas strategy will add potential resources that will enable the UAE to achieve gas self-sufficiency, with the aim of potentially transitioning to a net gas exporter. At its meeting, the SPC announced new discoveries of gas in place, totaling 15 trillion standard cubic feet.

It also announced new discoveries of 1 billion barrels of oil in place and approved ADNOC's new five-year business plan and capital investment growth of AED 486 billion between 2019-2023.

Qatar Walks Away from OPEC

Qatar is leaving the Organization of Petroleum Exporting Countries (OPEC) on January 1. The nation, which will be the first Middle Eastern country to exit the cartel, was part of OPEC for more than six decades. The nation's state-run oil firm, Qatar Petroleum, issued the announcement in a series of tweets. The country's last day as an OPEC member is January 1.

"The withdrawal decision reflects Qatar's desire to focus its efforts on plans to develop and increase its natural gas production," Saad Sherida Al-Kaabi, the country's newly-appointed minister of state for energy affairs, said in one of the tweets. "Achieving our ambitious growth strategy will undoubtedly require focused efforts, commitment and dedication to maintain and strengthen Qatar's position as the leading natural gas producer," Al-Kaabi said in one of the tweets.

The country has turned to gas as its main economic driver since being under a diplomatic and economic embargo by the other Middle Eastern countries over the past year-and-a-half which effects its oil funds.

Independent E&P Companies				
Company	Ticker Symbol	Currency	One-month Percent Change	Price as of November 26
Epsilon Energy	EPS.TO	CAD	20.40%	3.01
Groundstar Resources	GSA.V	CAD	0.00%	0.01
Pancontinental Oil & Gas	PCI.AX	AUD	0.00%	0.002
Anadarko Petroleum	APC	USD	-20.60%	52.37
Chariot Oil & Gas	CHAR.L	GBP	-16.90%	2.45
Apache Corp.	APA	USD	-15.90%	35.37

Finance Companies Express Interest in Port Harcourt Refinery

NNPC, Nigeria's state-owned oil company, revealed that a number of the finance companies it has approached to modernize the country's refineries have expressed interest in the modernization of the Port Harcourt refinery.

Ndu Ughamadu, Group General Manager, Group Public Affairs Division said according to the schedule set by the Ministry of Petroleum, the refineries will be fully operational by 2019 and will add their production capacity to that of the Dangote refinery that is currently under construction. The modernization of its refineries, along with the addition of the Dangote refinery, will bring the West African nation one step closer if not to the final step to the end of costly petroleum product imports.

The combined capacity of the Kaduna, Warri and Port Harcourt refineries is currently 445,000 bpd. The goal of the Nigerian government is to increase this production capacity.

Aqualis Offshore Reaches Rig Move Milestone

Aqualis Offshore marked attendance on its 2,000th mobile offshore unit rig move when the *Deep Driller 8* jack-up rig was positioned at an offshore wellhead platform on the east coast of India in late October.

The *Deep Driller 8* is a Kfels Super B class, self-elevating, cantilever, independent leg, jack-up rig. It is owned and operated by Aban Singapore Pte Ltd.

MiX Telematics Scores Sonatrach Contract

MiX Telematics entered into a contract to provide telematics solutions to Algeria's state-run oil & gas producer, Sonatrach. MiX's channel partner in the region, Algeria Telecoms Satellite (ATS), will also provide Sonatrach with a fleet management solution to address their safety, efficiency and compliance needs for 1,000 of their vehicles.

MiX Telematics said it has already installed its fleet solution in 500 vehicles belonging to Sonatrach subsidiary petroleum company Naftal. Based on the framework of the contract, MiX could potentially service 18,000 vehicles over several years, including vehicles operating for other Sonatrach divisions.

Magseis Acquiring Seismic Technologies from Fairfield

Magseis and Fairfield Geotechnologies have entered into an agreement whereby Magseis will acquire the Seismic Technologies business from Fairfield comprising data acquisition, nodal and system sale & rental activities including all shares in Fairfield's wholly owned UK subsidiary WGP Group.

The consideration in the transaction comprises a combination of cash, Magseis shares, warrants and an earn-out payment, with the agreed purchase price based on an enterprise value of approximately $233 million.

Fairfield Seismic Technologies is a provider of marine ocean bottom nodal (OBN) seismic systems. The business has performed 45 OBN surveys globally since 2005 and owns an extensive portfolio of intellectual property for both OBS, land and permanent reservoir monitoring solutions.

The parties have agreed that the purchase price payable by Magseis shall be based on an enterprise value for the business of approximately $233 million. The final purchase price will be determined based on the business' level of cash, debt and working capital at time of completion of the transaction.

Based on the estimated level of cash, debt and working capital, the purchase price will be settled by the following elements a cash consideration of $165 million; 33.5 million Magseis shares, where number of shares issued to Fairfield is calculated based on a value of $85 million and NOK 21.00 per share. The cash consideration will be adjusted for the actual level of cash, debt and working capital at completion.

In addition, Fairfield will receive an earn-out payment related to the Al Shaheen project (included in the backlog of the business) where Fairfield will receive 40% of the net cash generated from the project; and 18.25 million warrants for shares in Magseis exercisable at any time during the five-year period after completion of the transaction. The exercise price for the warrants will be set at 150% of the lower of (i) the subscription price in the contemplated equity offering and (ii) the highest of NOK 21.00 and 80% of the subscription price.

Oilfield Helping Hands to partner with BJ Services

Oilfield Helping Hands (OHH) announced a new partnership with BJ Services' Team BJ Foundation. Team BJ Foundation was established after Hurricane Harvey as an employee-funded financial hardship resource for BJ employees in crisis.

Through this partnership, OHH will provide administration for Team BJ Foundation, which includes receiving and reviewing applications for assistance and distribution of funds. BJ will be an active corporate member of OHH through participation in fundraising events and sponsorships.

Lundin Faces Penalties on Sudan

More than a decade after it exited its operations in what was then Sudan, Lundin Petroleum is facing economic penalties for its previous activities there. According to the company it received notification from the Swedish Prosecution Authority indicating it may be liable to a corporate fine and forfeiture of economic benefits in connection with the preliminary investigation into past operations in Sudan from 1997 to 2003.

The notification indicated that the Prosecutor may seek a corporate fine of SEK 3 million and forfeiture of economic benefits from the alleged offense in the amount of SEK 3,282 million, based on the profit of the sale of the Block 5A asset in 2003 of SEK 729 million. Any potential corporate fine or forfeiture would only be

Drilling & Service Companies				
Company	Ticker Symbol	Currency	One-month Percent Change	Price as of November 26
Fugro	FUR.AS	AUD	1.00%	10.91
RPC Inc	RES	USD	-4.80%	14.04
KBR Inc	KBR	USD	-5.60%	18.59
Weatherford International	WFT	USD	-72.20%	0.66
GE	GE	USD	-39.60%	7.58
CGGVeritas	CGG.PA	EUR	-37.70%	1.36

imposed after the conclusion of a trial, should one occur.

The investigation is in its ninth year and Lundin Petroleum remains convinced that there are absolutely no grounds for any allegations of wrongdoing by any company representatives and it will firmly contest any corporate fine or forfeiture of economic benefits.

The timeframe for a decision as to whether and when any corporate fine or forfeiture may be imposed remains uncertain but would only be incurred at the conclusion of a trial, if any, of matters currently under investigation. Fully in line with the company's position that there are absolutely no grounds for any allegations of wrongdoing by any company representatives, the company will firmly contest any corporate fine and forfeiture of economic benefits.

Egypt Looking for $10 Billion in New Investments

In a Ministry of Petroleum statement released on November 10, Tarek El Molla, Egypt's petroleum minister, said the country was looking to attract an estimated $10 billion in new investments during the current fiscal year. The funds will be used in the search for oil and gas and to further the development of discovered fields.

According to the El Molla statement, demand from major international companies represent a clear message on the confidence of foreign companies in the improving investment climate in Egypt, due to the reforms the government has been implementing.

He added that there are plans to achieve steady growth in oil investments in the upcoming years, especially in light of the ongoing expansion of exploration agreements, the implementation of field development programs, and major projects producing gas from deep water in the Mediterranean.

He went on to say that his Ministry was working to create an appealing investment climate in the oil and gas industry through a project to develop and modernize the oil sector.

Unique Group Signs Partnership Agreement with Deepwater Corrosion Services

Unique Group entered into a cooperation agreement with Deepwater Corrosion Services Inc. As part of the agreement, Unique Group will offer Deepwater's technologically advanced corrosion control solutions to the Middle East Market.

Over the past 30 years, Deepwater who have offices worldwide, have been delivering world-class solutions to protect offshore infrastructure from corrosion by developing more efficient systems to protect, monitor and extend the productive lives of ageing assets. The solutions include cathodic protection (CP), permanent CP monitoring, CP design & engineering and corrosion inspection & survey.

Deepwater's sacrificial (SACP) and impressed current (ICCP) systems are well known in the corrosion industry as the designs are easily retrofitted. SACP systems include the RetroPod, RetroLink, RetroMat and RetroSled, all connected using the RetroClamp system, which can also be used to install and connect permanent monitoring systems. Some of the ICCP systems are RetroBuoy and RetroBuoy Junior, RetroMat ICCP and the Raparound Anode System.

Lekoil Seeks Date with Federal High Court

Lekoil Ltd applied to Nigeria's Federal High Court in Lagos to "expedite" the consent process for the company's acquisition of an additional 22.86% interest in the OPL 310 license. Currently the company holds a 40% working interest in the license and a 70% economic interest.

The company said it has not received ministerial consent or received a "satisfactory explanation" for why consent for the acquisition has not been forthcoming. Lekoil was previously scheduled for a hearing by the judge who adjourned it until November 29.

Global Terminates Arrangement for Farm-in Advisor

Global Petroleum provided an update on its operations in Namibia which focused on its acquisition of a Petroleum Agreement for Block 2011A offshore Namibia. The License for Block 2011A, designated PEL 0094, was issued post the reporting period.

Block 2011A is located in the Walvis basis, immediately to the east of the company's current license, PEL 0029, which comprises Blocks 1910B and 2010A.

Global will hold an 85% interest in PEL 0094 as operator. The company is partnered with Namcor and Namibian private company Aloe Investments, who will have carried interests of 10% and 5% respectively. The combination of the two licenses gives Global an interest in an aggregate area of 11,608 sq kms offshore Namibia, which is one of the largest net acreage holdings in the region.

The company has terminated its arrangement with Stellar Energy Advisors who had been conducting a structured farm-out process for PEL 029, Although no farminee has been identified to date, Global plans to continue its search for potential farm-in partners.

OTS Completes Chevron South Africa Buy

Off the Shelf Investments (OTS), Glencore's Black Economic Empowerment (BEE) in South Africa, has completed the $973 million acquisition of Chevron's downstream assets in South Africa. The transaction is being funded by Glencore and comes after South Africa's Competition Tribunal gave a conditional approval earlier this in Q3 of this year.

OTS already holds a 23% stake in Chevron South Africa (CSA), the latest stake acquisition gives the company a total of 98% of the company. The remaining 2% in CSA is to be held by the company employees. Upon closing of the deal, CSA is now to be called Astron Energy

Major E&P Companies				
Company	Ticker Symbol	Currency	One-month Percent Change	Price as of November 26
Engie	ENGI.PA	EUR	6.20%	12.56
Chevron	CVX	USD	-2.20%	114.95
ExxonMobil	XOM	USD	-6.00%	76.98
ConocoPhillips	COP	USD	-10.7	64.7
Total	FP.PA	EUR	-8.70%	48.08
ENI	ENI.MI	EUR	-8.10%	14.15

The acquisition includes the 100,000-bpd refinery in Cape Town, a lubricants plant in Durban, and 850 service stations and storage facilities. The transaction also gives OTS a 100% stake in Chevron Botswana. Under the terms of the deal, OTS has committed to invest $500 million to develop the Cape Town refinery.

Ghanaian Local Content Grows by Leaps and Bounds

Local content in Ghana is growing by leaps and bounds in the petroleum sector. According to the country's energy minister, John Peter Amewu, over 600 indigenous companies have been awarded various contracts to provide services in the sector.

Amewu was addressing the opening session of the 4th Africa Oil Governance Summit organized by the Africa Center for Energy Policy (ACEP) under the theme "Harnessing the Potential of Local Content for Economic Growth and Inclusive Development."

In November 2013 laws were passed calling for the promotion of value-addition and job creation through the use of local expertise, goods and services business, financing in the petroleum industry value chain and their retention in Ghana. At the commencement of oil production at the Jubilee Field off Cape Three Points in the south-western part of the country, less than 100 Ghanaian firms were registered to provide services in the oil and gas industry. As of September, there were over 600 indigenous Ghanaian companies registered and providing goods and services to the industry.

Amewu offered up an example of the progress Ghanaian firms have made saying, "The Sankofa-Gye Nyame field in Ghana has awarded over contracts worth $1.8 billion to indigenous companies and about 56% of workers on the FPSO are Ghanaian."

The Minister further disclosed that the oil and gas industry currently employed between 75%-78% local workforce in the middle level and managerial roles.

Sirius Buys into Service Firm

Nigerian firm Sirius Petroleum entered into a conditional sale purchase agreement (SPA) with service firm Precision Energy Group (PEG) to acquire a 75% stake in Precision Energy Tetra 109, a wholly owned subsidiary of PEG.. The Sirius JV has in turn conditionally agreed to acquire a direct 40% equity and up to 80% economic interest in Tetrarch from Tetrarch Holdings.

Tetrarch is an 80% shareholder in Tetra Energy Services, which wholly owns Tetra Petroleum Oilfield Services (TPOS). TPOS entered into a petroleum services contract (PSC) to provide certain petroleum services to the owners of the license known as OML 109.

Once the transactions are completed and after recovery of its costs, Sirius will hold an effective indirect economic 30% interest in the cash flows of TPOS through its economic interest in Tetrarch. Subject to completion of the transactions, Sirius JV intends to provide petroleum services to Tetrarch and therefore TPOS in relation to the PSC in which Sirius and its operational partners expect to take an active role in providing such services.

African Rig Count

Country	2018 July	2018 August	2018 September	2018 October
Algeria	45	49	49	46
Angola	4	4	4	4
Benin	0	0	0	0
Cameroon	1	1	1	1
Chad	1	5	7	7
Congo	3	3	4	4
Congo (DRC)	0	0	0	0
Cote D'lvoire	1	1	1	1
Djibouti	1	1	1	0
Egypt	32	29	23	25
Equatorial Guinea	0	0	0	0
Ethiopia	2	2	2	2
Gabon	4	3	3	4
Ghana	1	0	0	0
Guinea	0	0	0	0
Kenya	9	8	8	8
Liberia	0	0	0	0
Libya	5	8	9	9
Mauritania	0	0	0	0
Morocco	1	1	1	1
Mozambique	0	0	0	0
Namibia	0	0	1	0
Niger	1	1	1	1
Nigeria	16	14	14	15
Senegal	0	0	0	0
Sierra Leone	0	0	0	0
South Africa	0	0	0	0
Sudan*	0	0	0	0
Tanzania	0	0	0	0
Togo	0	0	0	0
Tunisia	3	3	3	3
Uganda	0	0	0	0

Source: BHGE

*Data not available

Africa Production of Crude Oil

(including Lease Condensate, Thousand Barrels/Day)

Country	2018 August	2018 September	2018 October
Algeria	1057	1049	1054
Angola	1462	1519	1533
Cameroon	81	80	80
Chad	91	91	90
Congo (Brazzaville)	313	312	324
Congo (Kinshasa)	20	20	20
Cote d'lvoire (Ivory Coast)	28	28	27
Egypt	642	641	640
Equatorial Guinea	126	124	131
Gabon	188	187	186
Ghana	123	120	121
Libya	950	1053	1114
Mauritania	0	0	0
Morocco	0.5	0.5	0.5
Niger	20	20	20
Nigeria	1722	1748	1751
South Africa	3	3	3
Sudan and South Sudan	220	221	225
Tunisia	49	48	48
Total Africa	7095.5	7264.5	7367.5

Various sources including EIA, IEA and OPEC

Production of Natural Gas Plant Liquids

(Thousand Barrels/Day)

Country	2018 February	2018 March	2018 April
Algeria	320	320	320
Angola	51	51	51
Congo (Brazzaville)	15	15	15
Egypt	217	215	217
Equatorial Guinea	21	21	21
Libya	31	31	31
South Africa	5	5	5
Tunisia	3.5	4	3.5
Total Africa	663.5	662	663.5

Various sources including EIA, IEA and OPEC

World Rig Count

Country	September 2018 Land	September 2018 Offshore	September 2018 Total	Variance From Last Month	August 2018 Land	August 2018 Offshore	August 2018 Total	September 2017 Land	September 2017 Offshore	September 2017 Total
Latin America	167	25	192	0	168	24	192	150	27	177
Europe	56	30	86	1	53	32	85	58	33	91
Africa	90	19	109	5	87	17	104	66	13	79
Middle East	347	48	395	-7	351	51	402	347	48	395
Asia Pacific	140	82	222	-3	137	88	225	120	69	189
United States	1,033	20	1,004	3	1,031	19	1,050	922	18	940
Canada	199	2	201	-19	219	1	220	209	1	210
Worldwide Total	2,032	226	2,258	-20	1,250	232	2,278	1,872	209	2,081

Source: BHGE

OPEC Oil Production
(Thousand Barrels/Day*)

Country	2018 August	September	October
Algeria	1057	1057	1054
Angola	1462	1462	1533
Congo	313	313	324
Ecuador	531	531	525
Equatorial Guinea	126	126	131
Gabon	188	188	186
Iran, I.R.	3597	3597	3296
Iraq	4642	4642	4653
Kuwait	2806	2806	2764
Libya	950	950	1114
Nigeria	1722	1722	1751
Qatar	618	618	609
Saudi Arabia	10404	10404	10630
UAE	2974	2974	3160
Venezuela	1239	1239	1171
TOTAL OPEC	32629	32629	32900
OPEC exluding Iraq	28005	28005	28247

Source: OPEC

** Based on secondary sources*

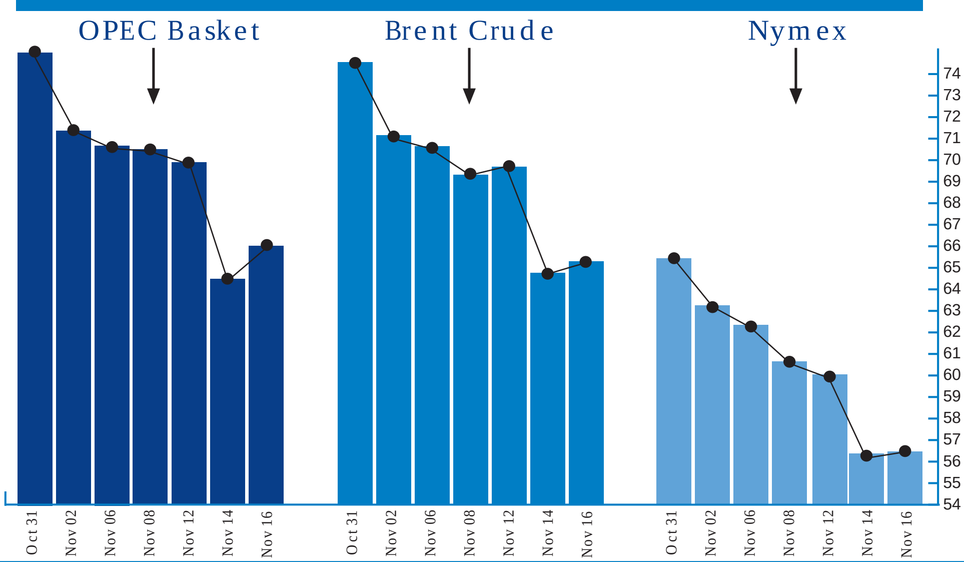
World Oil Production
(million barrels per day)

Country	2018 Q2 2018	August	September
Americas	21.89	22.35	23.16
Canada	4.84	5.03	4.89
Chile	0.01	0.01	0
Mexico	2.13	2.09	2.07
United States	14.92	15.22	16.2
Asia Oceania	0.38	0.38	0.41
Australia	0.31	0.31	0.35
Others	0.07	0.07	0.07
Europe	3.31	3.32	3.14
Norway	1.74	1.81	1.61
UK	1.06	1.01	0.99
Others	0.51	0.51	0.53
Total OECD	25.58	26.05	26.71
Total Non OECD	29.39	29.03	29.05

Source: IEA Oil Market Report

October 31	$
OPEC Basket	75.24
Brent Crude	74.84
Nymex	65.44
November 02	
OPEC Basket	71.35
Brent Crude	71.11
Nymex	63.28
November 06	
OPEC Basket	70.88
Brent Crude	70.64
Nymex	62.34
November 08	
OPEC Basket	70.68
Brent Crude	69.29
Nymex	60.86
November 12	
OPEC Basket	69.82
Brent Crude	69.81
Nymex	60.08
November 14	
OPEC Basket	64.51
Brent Crude	64.88
Nymex	56.44
November 16	
OPEC Basket	66.00
Brent Crude	65.29
Nymex	56.68

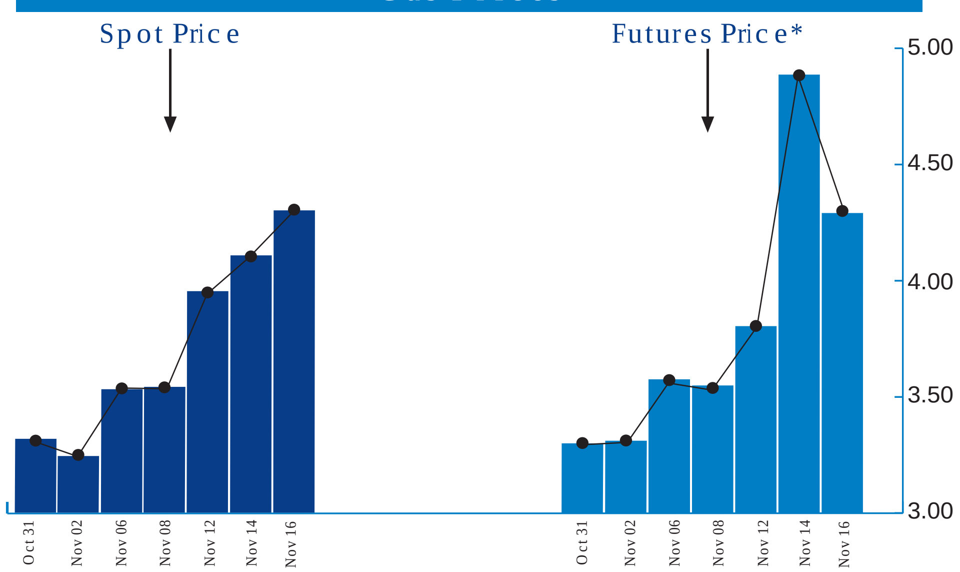
Oil Prices



October 31	$
Henry Hub	3.31
New York	3.30
November 02	
Henry Hub	3.26
New York	3.31
November 06	
Henry Hub	3.53
New York	3.58
November 08	
Henry Hub	3.54
New York	3.55
November 12	
Henry Hub	3.96
New York	3.80
November 14	
Henry Hub	4.10
New York	4.89
November 16	
Henry Hub	4.30
New York	4.29

Dollars per BTU

Gas Prices



Data compiled by Petroleum Africa from various sources including OPEC, EIA and others

Conferences

November 2018			
5-9	Africa Oil Week 2018	Cape Town, South Africa	www.Africa-oilweek.com
12-15	Abu Dhabi International Petroleum Exhibition and Conference (ADIPEC)	Abu Dhabi, UAE	www.adipec.com
14-15	Gas Options: North & West Africa Summit	Marrakech, Morocco	www.gasoptions-nwafrica.com
21-22	9th Annual Ghana Summit	Accra, Ghana	www.cwcghana.com
22-22	'Big Five' Board Awards 2018	London, UK	www.africa-petroleumclub.com
26-27	2nd Africa Oil & Gas Local Content Conference & Exhibition	Luanda, Angola	www.ametrade.org
December 2018			
3-6	The 8th Practical Nigerian Content Forum (PNC)	Yenagoa, Nigeria	www.cwcpnc.com
3-4	BBTC MENA 2018 – Bottom of the Barrel Technology Conference	Manama, Bahrain	www.europetro.com
5-6	ME-CAT 2018 – Middle East Catalyst Technology Conference	Manama, Bahrain	www.me-cat.biz
10-12	2nd ECOWAS Mining & Petroleum Forum & Exhibition	Abidjan, Cote d'Ivoire	www.ecomof.com
11-12	International Gas Cooperation Summit	Cape Town, South Africa	www.igcs-sa.com
11-13	Mauritanides 2018	Nouakchott, Mauritania	www.mauritanidesmr.com
January 2019			
23-24	6th Maximising Propylene Yields	Barcelona, Spain	www.wplgroup.com
February 2019			
6-7	2nd Morocco Oil & Gas Summit 2019	Marrakesh, Morocco	www.morocco-summit.com
11-13	Egypt Petroleum Show 2019 (EGYPS)	Cairo, Egypt	www.egyps.com
March 2019			
10-13	North Africa Petroleum Exhibition and Conference (NAPEC)	Algeria, Algeria	www.napec-dz.com
26-27	Power & Electricity World 2019	Johannesburg, South Africa	www.terrapinn.com
April 2019			
1-5	LNG 2019	Shanghai, China	www.lng2019.com

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