ALIGN RESEARCH

Anglo African Oil & Gas

18th January 2019

Highly profitable small cap O&G play with present stock price underpinned by current activities and exploration potential offering further upside

CONVICTION BUY – Price target 28.23p

Anglo African Oil & Gas (AAOG) joined AIM in March 2017 and subsequently acquired a 56% stake in the Tilapia Field in the Republic of the Congo for US$5 million. This was a cracking deal as Tilapia is a proven producing asset with substantial upside potential in the Lower Congo Basin, an established and prolific location for hydrocarbons. Multiple discoveries have been confirmed from the TLP-103C well in the R2 and Mengo reservoirs and now the well is being drilled deeper.

Mengo discovery and R1/R2 look set to boost production to 750 bopd

A 44m oil column in the Mengo has been confirmed - nearby fields produce 500 bopd per well with stimulation. Experts believe that 400 bopd is achievable with water flooding from the TLP-101. **Added together, this suggests a minimum of 750 bopd, making AAOG nicely cash flow positive.**

Djeno is the big prize and success here could be transformational

TLP-103C is now targeting the Djeno, a reservoir where Eni, TOTAL, CNOOC & SOCO are all producing nearby at a naturally pressurised 5,000 bopd per well. Even if AAOG miss it this time round, lessons learnt will be invaluable in drilling TLP-104, planned to be drilled back to back with TLP-103C.

Existing infrastructure allows discoveries to go into production rapidly

AAOG is shaping up to be a profitable company, even ahead of any success in Djeno. The company benefits from having existing topside infrastructure which allows the team to quickly turn confirmed resources into production.

Risked NPV suggests upside of more than 170%

Our conservative valuation shows the potential. We initiate coverage of AAOG with a first target price of 28.23p and a **Conviction buy** stance.

Table: Financial overview

Year to end Dec	2016A	2017A	2018E	2019E
Revenue (£'000)	-	227	200	6,900
PTP (£'000)	(937)	(3,141)	(3,664)	1,600
EPS (p)	(2.21)	(5.75)	(3.01)	0.69

Source: Company accounts & Align Research

This investment may not be suitable for your personal circumstances. If you are in any doubt as to its suitability you should seek professional advice. This note does not constitute advice and your capital is at risk. This is a marketing communication and cannot be considered independent research.

Key data

EPIC	AAOG
Share price	10.35p
52 week high/low	16.55p/6.00p
Listing	AIM
Shares in issue	237,929,038
Market Cap	£24.6m
Sector	Oil

12 month share price chart

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IMPORTANT: Anglo African Oil & Gas is a research client of Align Research. Align Research & a Director of Align hold interests in the shares of AAOG. For full disclaimer information please refer to the last page of this document.

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Business overview

Anglo African Oil & Gas Operations

Anglo-African Oil & Gas (AAOG) is an Africa-focused oil and gas company which is seeking to increase production from its existing asset in the Republic of the Congo.

• **The Republic of the Congo** – The Tilapia oilfield (56%) lies 1.8km offshore and commenced production in 2008. Current production is around 38 bopd of 39-41° API light sweet crude oil. **P90 reserves in the R1/R2 are estimated to be 7.6 million barrels**. The company is currently drilling the TLP-103C well, the first of a planned six-well programme, which is focused on development drilling of the known Mengo horizon and exploration drilling of the deeper Djeno horizon.

Installed infrastructure on the Tilapia production platform. Source: Company

Republic of the Congo

The Republic of the Congo is also known as Congo Brazzaville and is located in West Africa. The country is the former French Congo and lies to the north of the Democratic Republic of the Congo (DRC). The country is 342,000km² is size, which is about 40% larger than the UK. The state capital is Brazzaville, but the economic centre is seen to be Pointe Noir which is the headquarters of the country's oil and gas industry. The country is quite sparsely populated with a population of only 5.1 million.

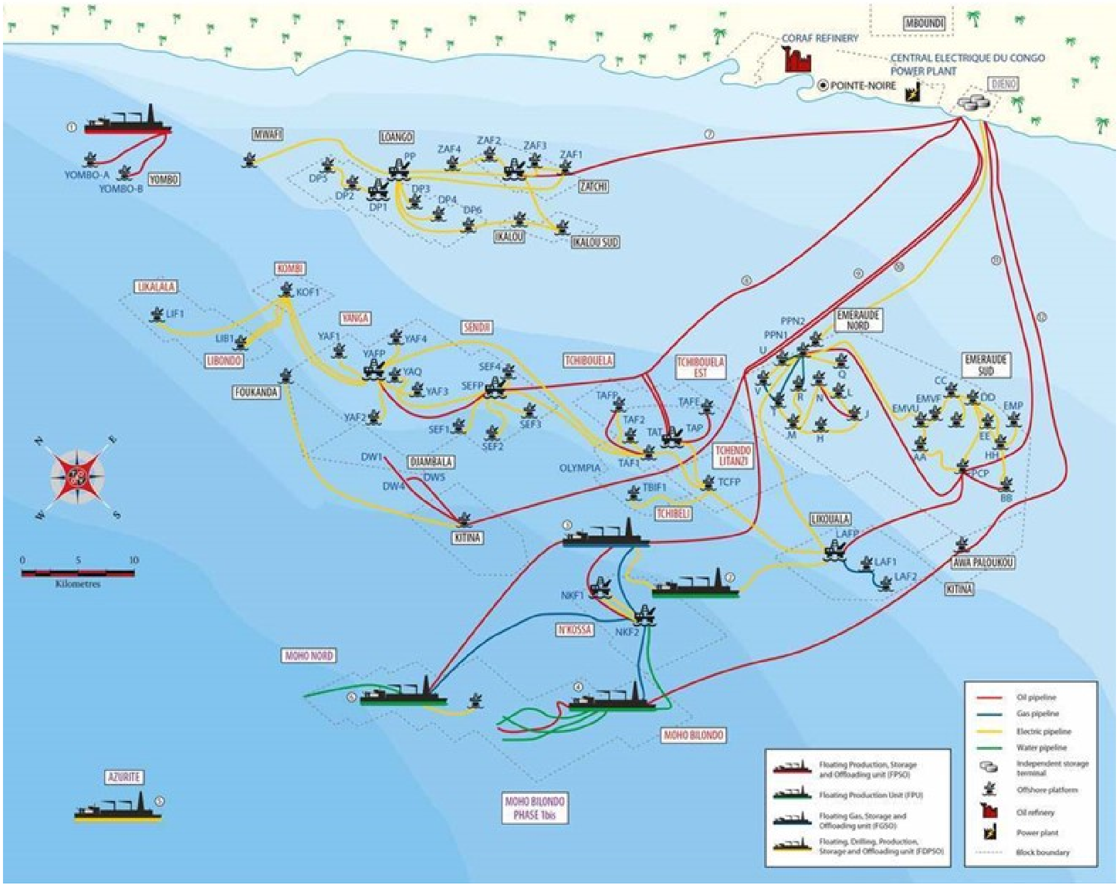
Location of the Republic of Congo. Source: Bing

Independence was gained from France in 1960 and today the President is Denis Sassou-Nguesso, an ex-military leader, who has dominated politics in the country over the past decades. He was first President from 1979 to 1992 and then returned to power in 1997 following a short civil war where he received the backing of troops from Angola. Subsequently, he has served as President ever since 1997, having been re-elected in March 2018 and then assuming office for a five-year term in April 2016.

The Republic of the Congo has a mixed economy with something like 65% of GDP coming from the oil and gas industry which accounts for over 90% of exports. Oil production began in the country in 1960 and by the late-1970s it had become a significant oil producer. In January 2018, oil production reached an all-time high of 370,000 bopd, mostly from offshore. This history of oil production means that there is a good level of oilfield support services provided locally.

The country is one of Africa's largest petroleum producers after the likes of Nigeria and Angola and is benefiting from the revival of exploration and development activity seen in recent years. Majors active in the Republic of Congo are TOTAL and Eni which have enjoyed a high level of success in drilling. Key discoveries over the last decade or so include the Moho-Bilondo field and the Lianzi Field.

Moho-Bilondo (TOTAL 53.5%, Chevron 31.5%, SNPC 15%) was the country's first deepwater project which came on stream in 2008, with production rising to 90,000 bopd in 2010. In 2013, TOTAL and its partners initiated two projects (Moho Phase 1bis and Moho Nord) with capex of over US$10 billion, which at the time represented the largest-scale development offshore the Republic of the Congo. Mohho Phase 1bis began in 2015 and the redevelopment allowed oil production to increase by 40,000 bopd.



Offshore hydrocarbons infrastructure in the Republic of Congo. Source: Wildcat International.

Moho Nord is a vast project which is now producing from untapped reserves at the northern end of the Moho-Bilondo licence block. Launched in 2017, Moho Nord taps into two remaining reservoirs with a total of 33 wells. The Modo Nord project production plateau is 140,000 bopd. Between them Moho Phase 1bis and Moho Nord are currently producing at a rate of 140,000 bopd.

Elsewhere, the Lianzi field (TOTAL 36.75%, Chevron 31.25%, ENI 10%, Sonangol 10%, SNPC 7.5% and Galp Energia 4.5%) was a joint development with profits to be shared by the Republic of the Congo and Angola. Located 65 miles offshore and in 3,000 feet of water, Lianzi represented the first cross-border oil development project offshore Central Africa. Production commenced in 2015 and has been planned to hit a peak of 40,000 bopd.

Background

The company was incorporated in England and Wales in January 2001 to acquire Sonnberg, which was involved in diamond exploration under the name Namibian Resources. The strategy of the company was to seek opportunities in the mining industry in Namibia which proved to be unsuccessful. In June 2015, the company was approached by the current Executive Directors who were in the midst of raising funds from London-based institutional investors to acquire Petro Kouilou (PK) from Sister Holding SAS and to fund PK's share of development expenses at Tilapia. In December 2015, the company entered into a conditional agreement to acquire PK, a company incorporated in the Republic of the Congo which owned a 56% stake in the Tilapia oil field.

AAOG joined AIM in March 2017, following a placing of 50 million shares at 20p per share which raised £10 million and the stock started trading with an initial market capitalisation of £10.6 million. The funds raised were used to finance the acquisition of a 56% stake in the producing Tilapia oil field in the Republic of the Congo along with a multi-well near term drilling programme targeted a major increase in production. The project was acquired from Sister Holding SAS for a total of US$5 million, paid US$2.5 million in cash and US$2.5 million in ordinary shares.

On admission, the company had a detailed development/workover programme lined up for the ensuing twelve months. May 2017 saw the start of the first workover in the Tilapia oil field which involved the re-perforation and acidisation of the R2 reservoir in well TLP-102. Tendering for the drilling of a new well TLP-103 commenced in August 2017.

By January 2018, progress had not been as swift as expected which led to a number of board changes to strengthen the management team. James Berwick, who has an impressive track record in the African oil and gas sector, was appointed CEO and three new Non-Executive Directors joined the board: Phil Beck, Nick Butler and Sarah Cope.

With a new CEO in place, the company then began to report positive momentum in May 2018, at the time when a conditional placing raised £7.4 million at 8p per share. This new money allowed AAOG to fund the entire cost of drilling the multi-horizon TLP-103 well, which included its partner SNPC's share of drilling and workover costs (which had not been budgeted for on listing). Sister Holdings SAS declined to participate in the placing.

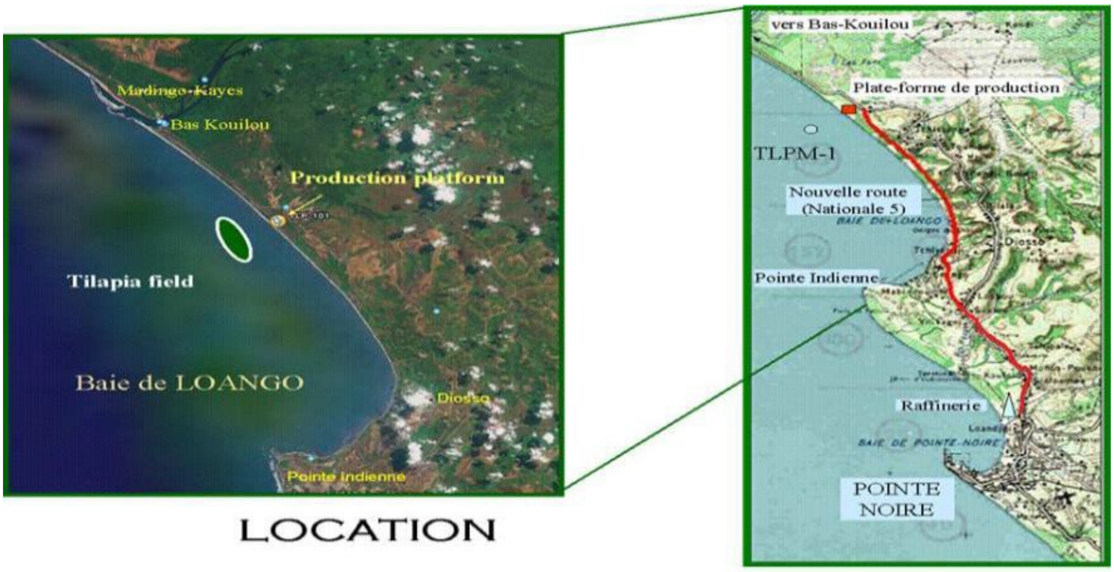
The TLP-103 well was spudded in early October 2018. Later on that month, AAOG announced a conditional £5 million Convertible Loan Note Financing Facility with Sandabel Capital which would provide future funding flexibility where needed for the TLP-103C well and for working capital. These funds could be drawdown over the following 12-month period. The Loan Notes were to be issued at 90% of their par value and redeemed at full value. Sandabel also received conversion rights which allowed it to exercise whole or part into ordinary shares subject to the terms of the conversion notice.

Following the announcement of multiple discoveries being confirmed by well TLP-103C in early January 2019, the company raised £6 million at 10p per share. The funds raised allowed the company to complete the TLP-103C well and were seen to replace the capital which was available under the Sandabel facility which was then cancelled. **Undoubtedly, this should be seen as a positive move.**

Operations

TILAPIA

AAOG is focused on increasing production from its 56%-owned Tilapia oil field located in the Lower Congo Basin and adjacent to multiple 1 billion-barrel fields including the ENI operated Litchdjilii field and the 5,000 bopd Minsala Marine field. Tilapia is located just 1.8 kilometres off the coast of the Republic of the Congo and the licence covers an area of 50.51km². The Tilapia oilfield is drilled through deviated wells from onshore which results in a significant cost saving compared to offshore drilling but with the production and storage facilities land-based onshore.



Tilapia lies 1.8km offshore & drilled from an onshore production platform. Source: Company

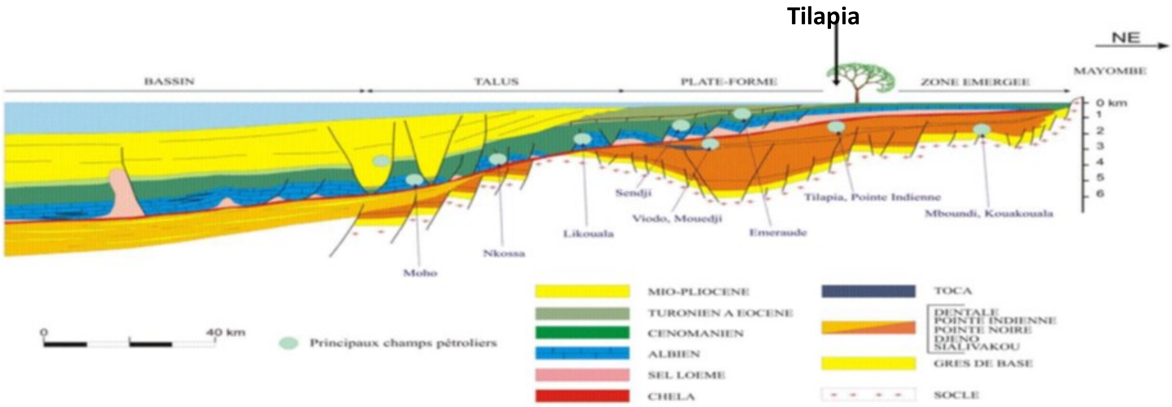
The Tilapia licence was awarded to the state oil company Société Nationale des Pétroles du Congo (SNPC) in 2006, which choose PK as a partner and operator and brought the oilfield into production in 2007. Currently, the field is producing around 38 bopd of 39-41° API light sweet crude from wells in the R1/R2 horizon. Since the company acquired PK with its 56%-holding in the project in early 2017, the plan has been to use workovers along with enhanced oil recovery techniques, to increase production from this horizon.

View of the onshore production platform. Source: Company

Tilapia has excellent infrastructure. The oil field is a 45-minute drive from Pointe Noire which is seen as the country's economic centre and 17 kilometres from the nearest refinery. Production is trucked to a local refinery with an offtake agreement contract already in place.

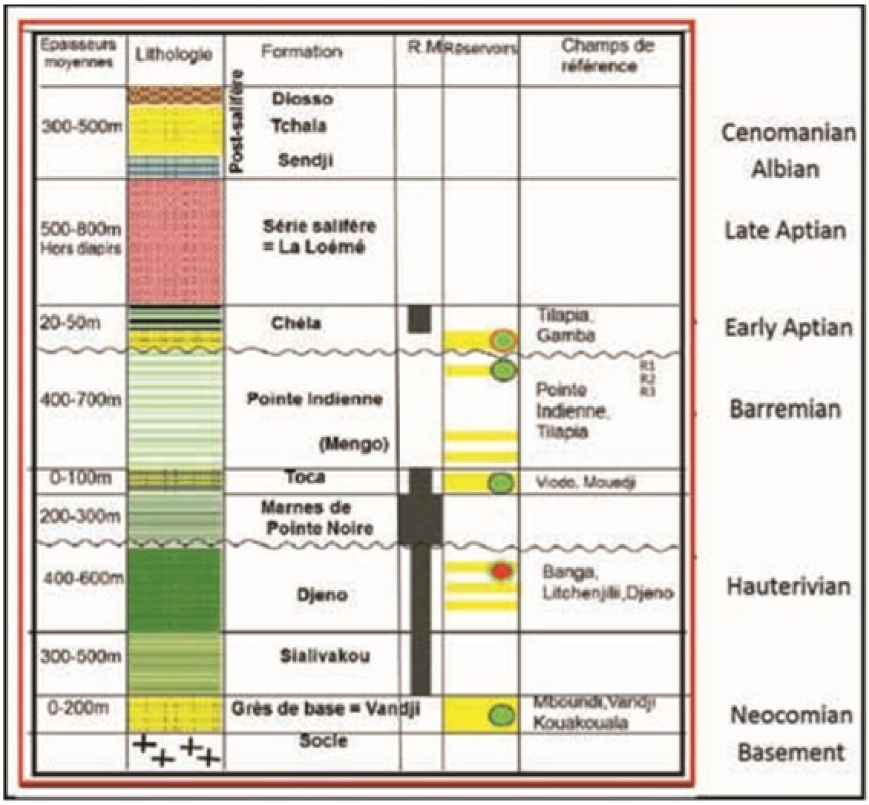
Geology

The Lower Congo Basin represents one of a series of prolific oil and gas basins that lie along Africa's Atlantic coast. The main reservoir and exploration targets in the Tilapia Licence are all pre-salt Cretaceous in age and the three formations that represent the company's main interests are: Pointe Indienne R1 and R2 Sands, the Mengo Sands and Djeno Sands.



Reservoir cross-section through the Lower Congo Basin. Source: Company.

Recent developments in seismic techniques have led to the interpretation of the presence of hydrocarbons in the Djeno Sands in the Tilapia licence area. The Djeno Sands have been shown to lie beneath the pre-salt layer in neighbouring fields Eni, SOCO International and Oryx where substantial production is being achieved in a conventional manner without any need for stimulation or fracking. This horizon has never been tested in Tilapia as the oil field was brought into production in the days before such seismic technology was available.



Tilapia area stratigraphic column. Source: LR Energy CPR in AIM admission document

The Djeno Sands reservoirs in neighbouring fields have been in production since 2013, producing at rates in the range of 4,750 – 5,000 bopd per well. These fields have enjoyed high flow rates, which are caused by the oil layer itself being naturally pressurised by lower lying high-pressure gas deposits.

Resources and Reserves

The Tilapia field is a faulted structural trap which at the time of the acquisition of PK had seen a total of six wells and two sidetracks drilled and there have been discoveries encountered at several horizons. In the Tilapia structure, the main producing horizon is the Pointe Indienne R2 sandstone.

	Gross on Licence			**Net Attributable**			**Operator**
	1P	2P	3P	1P	2P	3P	
Oil & Liquid Reserves (MMstb) Tilapia	0.0	0.199	0.277	0.0	0.095	0.132	PK
Total Oil & Liquids: MMstb	**0.0**	**0.199**	**0.277**	**0.0**	**0.095**	**0.132**	**PK**

Reserves developed and undeveloped. Source: LR Energy CPR in AIM admission document

The CPR in the AIM admission document also assessed contingent and prospective resources at the deeper levels in the structure for the Tilapia Field.

Discovery well TLP-101V encountered a 38m gross Lower Cretaceous Mengo sandstone interval when drilled in 2006, with good oil shows and the log analysis provides plenty of evidence for the presence of moveable hydrocarbons. The well flowed at a very low rate on test of 75 litres/hour (equivalent to 11 bopd), which is of little surprise as this reservoir is well-known for requiring stimulation. The unrisked potential resource volumes in the discovery as at 1st October 2016 are shown in the table below.

	Gross on Licence			**Net Attributable**			**Risk Factor**	**Operator**
	Low estimate	Best estimate	High estimate	Low estimate	Best estimate	High estimate		
Mengo	1.9	8.1	23.8	0.9	3.9	11.3	60%	PK
Total Oil & Liquids: MMstb	1.9	8.1	23.8	0.9	3.9	11.3		**PK**

Contingent Resources: discovery. Source: LR Energy CPR in AIM admission document

The deeper Lower Cretaceous Djeno reservoir is untested in the structure but this horizon has proved productive in nearby oil, gas and condensate fields at: Nene, Banga and Litchenjilii. It is anticipated to be located beneath the Mengo reservoir discover but was not penetrated by the TLP-101V well.

The October 2016 CPR assessed a gross prospective resource of 58.4 million barrels in the productive Djeno interval from which the adjacent Minsala field produces. Gross and net prospective resources attributable to this deeper exploration prospect are shown in the table overleaf.

	Gross on Licence			Net Attributable'			Risk Factor	Operator
	Low estimate	Best estimate	High estimate	Low estimate	Best estimate	High estimate		
Oil & Liquids Resources (MMstb) Djeno	6.0	15.9	42.3	2.9	7.6	20.1	25%	PK
Total Oil & Liquids: MMstb	**6.0**	**15.9**	**42.3**	**2.9**	**7.6**	**20.1**		
Gas Resources (Bscf) Djeno	97.8	24.7	625.0	46.6	117.6	297.5	25%	PK
Total Gas: Bscf	**97.8**	**24.7**	**625.0**	**46.6**	**117.6**	**297.5**	**25%**	

'Net attributable volumes equate to 56% of gross volumes after the deduction of the 15% royalty.

Prospective Resources. Source: LR Energy CPR in AIM admission document

Programme of work

On AIM admission in March 2017, the company set out a development/workover programme where the target was the workover of two existing wells (TLP-101 & TLP-102) with the intention of rapidly increasing production to 185 – 250 bopd. Production has yet to meet these initial expectations even though most of the initial effort has been focused on these two wells, along with the planning and drilling of the first new well TLP-103.

TLP-101 & TLP-102

Tilapia is currently producing around 38 bopd of 39-41° API light sweet crude from wells in the R1/R2 horizon intermittently. Since acquiring Tilapia, the company has worked over the TLP-101 and TLP-102 wells. TLP-101 has already been brought back into production at a flow rate which has exceeded that seen over recent years. TLP-102 is expected to be brought into production shortly.

Tilapia production platform. Source: Company

The first workover involved reperforation and acidisation of the R1 and R2 reservoirs in well TLP102 which will be drilled and connected to the manifold. The second workover involves the setting of a progressive cavity pump over the R2 reservoir in well TLP101. Due to an absence of gas in well TLP-102, a pump will need to be installed.

The CPR had suggested that these two workovers could increase production from 38 bopd to 185 bopd based on the P50 equivalent case. This was calculated on the assumption of achieving a rate of 80 bopd from TLP-101 and subsequently adding 20 bopd from the R2 reservoir in TLP-102 and 85 bopd from the R1 reservoir in this well. However, now a higher rate of production is anticipated based on the data gained during the workover. **The company's reservoir engineers expect a minimum flow rate of 120 bopd from TLP-102 once the pump has been installed.**

STOIIP				
Compartment	**Reservoir**	**Low P90**	**Best P50**	**High P10**
TLP-101ST (MMstb)	R2	0.85	2.12	5.01
TLP-102 (MMstb)	R1	1.31	2.97	6.53
TLP-102 (MMstb)	R2	5.31	8	11.4
Total Oil (MMstb)		7.47	13.09	22.94

Tilapia R1 and R2 Stock Tank Oil Initially In Place (STOIIP). Source: LR Energy CPR in AIM admission document

Moving ahead, the use of well TLP-102 might be changing. The team has always believed that the application of enhanced oil recovery techniques at wells TLP-101 and TLP-102 could substantially increase production. Most latterly, the stimulation exercise performed on the TLP-102 well has shown connectivity with TLP-101. This opens the door to using TLP-102 as a water injector to enhance production from TLP-101.

In early-January 2019, the Board pointed out that studies of such strategy by both AAOG and its specialist reservoir engineering contractor have predicted that a water injection system could increase oil production from TLP-101 to up to 400 bopd. The company is now obtaining estimates for the cost of this work as well as carrying out an assessment of the commercial viability of such a project.

TLP-103

AAOG has commenced the drilling of a planned six well programme at Tilapia with the drilling of the TLP-103 well and which has been designed as a multi-target well going through all three horizons (R1/R2, Mengo and Djeno). The board engaged SMP and Schlumberger to lead the drilling programme, working with AAOG's own highly experienced operations team.

The cost of drilling the well is US$8 million with a total of US$1.2 million having been spent ahead of drilling on long lead items such as casing, site overhaul and preparation. Also, infrastructure has been improved to meet the anticipated increase in production. It has not been plain sailing as the drilling of TLP-103 was temporarily halted in September 2018 and the rig had to be moved roughly 100m to the NW and the well re-spudded.

On 7th January 2019, the company announced that wireline logging by Schlumberger had confirmed a combined 44 metres of oil columns across multiple horizons at the TLP-103C well. Included in those numbers is the discovery of additional reservoirs. **The results have very much exceeded management's expectations and have set the scene for a major step up in production and cash flow.**

There were a number of highlights from that announcement. Firstly, a 26m oil column in the Mengo was identified in sandstones interbedded with claystones between 1874.8m and 1900.8m. Secondly, an aggregate 13m of oil columns across the new horizons was also identified between the R3 and the Mengo horizons in three layers of sandstones between 1473m and 1685.5m. Thirdly, an additional 5m oil column was identified in the R2 reservoir between 1282.7m and 1287.7m in line with the TLP-101V well located in fine sandstones. Importantly, all three discoveries were of Early Cretaceous (Barremian) age.

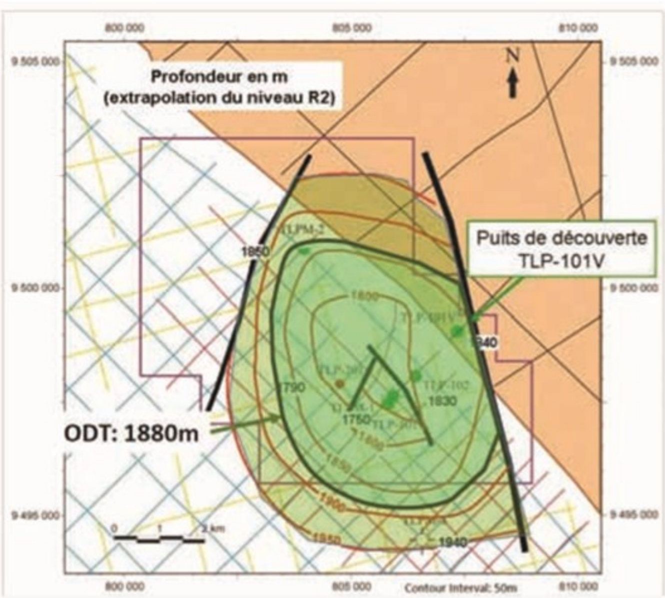
Modular formation dynamics tests have shown that the R2 reservoir is not depleted which serves to confirm that there is an onshore hydrocarbon system underlying the Tilapia licence area. Schlumberger's wireline logging was completed in the entire 12 ¼" section of the TLP-103C well which has been further confirmed by a petro-physical interpretation. **Based on the success that has been seen so far with this well, the board plans to commission work to update estimates of reserves which is expected to be available in Q1 2019.** In this section we go onto examine the assessments provided by the CPR dated October 2016.

The team had been expecting a smaller oil column in R1/R2 and an oil column half the size in the Mengo. So, these results are dramatically bigger. **The now expected 100 – 200 bopd from R1/R2 and 400 – 500 bopd from the Mengo would make it easy to achieve the 500 bopd plus which would make AAOG very cash flow positive and underpin the whole company.**

Mengo

As mentioned earlier, discovery well TLP-101V drilled in 2006 encountered a 38m gross Mengo interval with good oil shows and evidence on the log from the presence of moveable hydrocarbons. The unrisked potential resource volumes in the discovery as of 1st October 2016 are shown in the table on page 9.

The Mengo structure has been mapped on 2D seismic data on 500m grid spacing at the top of the Mengo horizon, with the trap seen to be a single four-way dip closure located beneath the R1/R2 reservoirs. The Lower Cretaceous Mengo sandstone reservoir is interpreted to be a turbiditic sandstone deposited in a lacustrine environment, a still water environment where very fine particles settle out to form lacustrine deposits.



Mengo depth structure map. Source: LR Energy CPR in AIM admission document

Well TLP-101V was a drilled down dip off the NW flank of the structure and the 38m gross interval encountered was of relatively poor reservoir quality with permeability averaging 0.5md and a porosity range of 8-10%. Oil Based Mud Image logs through the Mengo sands showed the presence of thin beds which were 2-8m thick. Following a review of the available petrophysical studies, CPR consultants LR assessed the gross oil-bearing interval (1,848 – 1,866m) with 13-20m net and an average porosity of 10%. With the limited stable flow of up to 11 bopd, achieving commercial rates would require stimulation.

The onshore Mengo/Kundi/Bindi (MKB) fields lie 30-40km to the SE of Tilapia and provide three analogous fields. By and large, the TLP-101V reservoir appears thinner than in the MKB fields. However, the seismic for the MKB fields does highlight considerable thickness changes which reflects the syn-rift depositional nature (where sediment was deposited at the same time as rifting affected the depositional area) of the Mengo sandstones. Recent Kundi wells drilled have porosity of 12-14% and 35-55m of net pay. The MKB fields are seen to be large faulted, four-way dip closures by seismic, the same as being seen at Tilapia.

The MKB fields originally produced in the 1980s and early 1990s from a limited number of wells and recovery during this period totalled 1.545 MMstb, which less than 1% of STOIIP. Production came from 6 productive wells with a further 8 stimulated (acid and/or frac) wells which were non-productive and another which did not encounter any reservoir.

More recently, the Kundi field was redeveloped in 2009 and two new development wells KUN-4 and KUN-5 started producing in 2011 at initial rates of 250 and 350 stb/d respectively, declining to 180 and 50 stb/d respectively by the end of November 2011. The 2011/12 period saw four further wells drilled: KUN-201 tested 315 stb/d, KUN-202 tested 383 std/d, KUN-203 tested 369 stb/d and KUN-204 where test results are unavailable. Well design and any stimulation that was performed is unknown but it is believed these were vertical wells. The more recent wells seem to have had a more impressive performance than the earlier developments.

The CPR consultants expect that the recovery factors will be low given the low permeability of the Mengo reservoir and be strongly dependent on well, density, well design and simulation techniques. This is well-illustrated by development studies on Kundi which have suggested 5% and 8% recovery factors for 27 and 42 wells respectively for a STOIIP of 340 MMstb.

STOIPP				
Compartment	**Reservoir**	**Low P90**	**Best P50**	**High P10**
Mengo Closure (MMstb)	Mengo	47.8	101	198

Mengo STOIIP. Source: LR Energy CPR in AIM admission document

The Mengo Formation STOIIP was calculated probabilistically, with a recovery factor for oil and gas applied deterministically. A recovery factor range of 4 – 8 – 12% was applied based on analogue field data and the company's intention of using horizontal well technology to develop this reservoir.

The board is considering using Fishbones Stimulation Technology to unlock the full value of the opportunity in the Mengo reservoir. Fishbones is seen to provide a new level of precision and efficiency in reservoir stimulation which seems to allow the stimulation to be targeted more accurately and efficiently.

Fishbones Jetting consists of small diameter hollow needles with jet nozzles that are installed within and protected by the liner. At depth these needles are then released by pressuring up the liner. The fluid jets out of the nozzles, and the formation ahead of the tubes is jetted away by a combination of erosion and acid chemical dissolution. Differential pressure across the liner drives the needles into the formation, penetrating the rock until the needles are fully extended. The system has four laterals installed at each depth.

Fishbones stimulation technology. Source: Fishbones AS

Importantly, the penetration length of the Fishbones laterals is the makeup length of the liner. Apparently, typically 12m is the achievable penetration, creating real and significant stimulation effects. Over the last three years, Fishbones has been deployed in multiple wells in different countries in the Middle East Gulf Region and Fishbone AS is looking to achieve similar success for the simulation technology in North Africa. Mengo could provide a good shop window for the technology.

In December 2018, Fishbones AS reported that an operator in North Africa had recently drilled a new onshore well in a tight limestone formation and subsequently deployed a Fishbones Jetting system equipped with 30 Fishbones subs and hence 120 laterals. **Initial inflow tests show extremely encouraging results with gas production rates exceeding the rates from comparable offset wells placed in the same formation that were stimulated by means of hydraulic fracturing.**

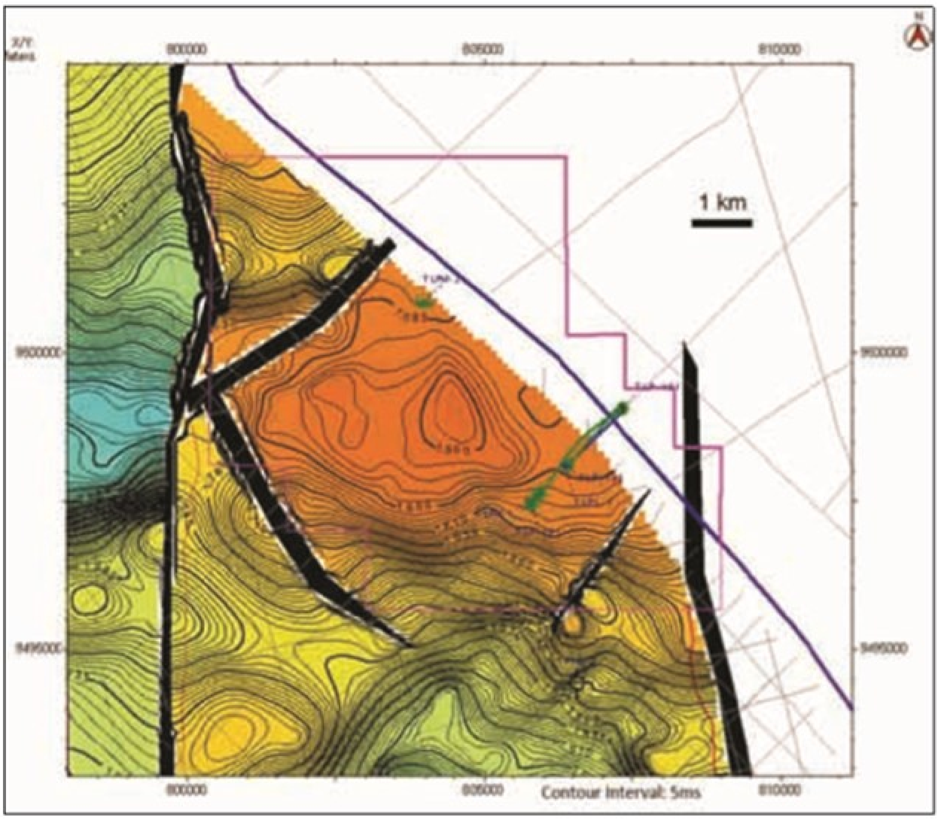
Fishbones expects the success of this application will open a new market for Fishbones Stimulation Technology in North Africa, repeating their experience in the Middle East Gulf Region where the last three years has seen Fishbones deployed in multiple wells in five different countries.

Djeno

The Lower Cretaceous Djeno reservoir exploration prospect is expected to be located beneath the Mengo reservoir discovery, although it was not penetrated by the TLP-101V well. The gross and net prospective resources attributable to the Djeno exploration target are shown in the table on page 10. The Mengo appraisal well TLP-103C has been deepened to test the Djeno potential which is expected to lie some 350m beneath the Mengo horizon by reference to the nearby Diyesi-1 well.

The October 2016 CPR tentatively mapped the Djeno prospect as a four-way dip closed structural trap with an Intra-Djeno reservoir horizon mapped on 2D seismic data, with 500m grid spacing. Seismic resolution at the Djeno Formation had a depth of > 50m. The seismic interpretation of Tilapia apparently corresponds to the high point on the basement judged on gravity and magnetic data.

Djeno Sands reservoirs in the neighbouring fields, have been in production since 2013, with production rates of 4,750 – 5,000 bopd per well. These fields have enjoyed high flow rates, which are caused by the oil layer itself being naturally pressurised by lower lying high-pressure gas deposits. There have been a number of significant exploration and production success stories in the Djeno sandstones which have been achieved by a number of operators including: Eni, TOTAL, CNOOC, SOCO International and New Age Oil and Gas.



Djeno Time (TWT) Structure Map. Source: LR Energy CPR in AIM admission document

The CPR interpreted the Djeno sandstones to have been deposited in a fluvial/lacustrine environment. There was limited well data available to review, but summary data on reservoir quality from the offset wells and fields has shown variability in reservoir quality, reflected in the selection of the input uncertainty ranges employed by the consultants in their volumetric calculations.

In addition, the CPR predicted the Djeno sandstone in the Tilapia structure to be gas with an oil rim. The consultants did point out that there was no maturation modelling study to support this opinion, which had been purely based on nearby analogue fields. It can be seen that the main source rock of the whole Congolese coastal basin is The Marnes de Pointe Noire Formation and the majority of wells drilled near Tilapia have shown the presence of wet gas, which is thought to be most likely associated with a producible oil rim as seen in the Néné-Lidongo trend.

Djeno HIIP				
Compartment	**Reservoir**	**Low P90**	**Best P50**	**High P10**
Djeno Oil rim (MMstb)	Djeno	20.3	53.2	140
Djeno Gas column (Bscf)	Djeno	142	356	893

Djeno hydrocarbons Initially in Place (HIIP). Source: LR Energy CPR in AIM admission document

The overall chance of discovery was assessed as being 25%. This was the product of the risk associated with the presence and effectiveness of four prospect components: trap geometry (70% chance), reservoir (80% chance), seal (90% chance) and charge (with no prospect specific geochemical or modelling study and the hydrocarbon phase therefore unknown – a 50% chance for oil rim was used).

Strategy for growth

In recent months the pieces have all begun to come together at AAOG, which has attracted the attention of investors. There has been the resumption of production at well TLP-101 at a higher rate than before it was shut in; plus, the real potential to produce up to 400 bopd using water injection. **All this has been eclipsed by news which has confirmed that multiple discoveries have been made at Tilapia with the Mengo success.**

Mengo was always going to need stimulation as it does not flow naturally at an interesting rate, but the analogous fields have seen anything up to 500 bopd per well. The obvious answer is hydraulic fracking and it is estimated that it could take 6-8 weeks for Schlumberger to get its kit over from Gabon although the team might opt to use the lesser known Norwegian Fishbones stimulation technology which does offer simple, accurate and efficient stimulation. **So, as things stand today, increasing production from TLP-101, TLP-103 and TLP-103C looks likely to provide a conservative minimum of 750 bopd from R1/R2 and Mengo, plus provide a pathway to more wells**. G&A is not expected to change and there looks to be a potentially impressive earnings stream stretching many years into the future. It has to be said that AAOG is starting to look like a proper oil company

Currently, AAOG has a 56% stake in Tilapia with its state-owned partner SNPC holding the remaining 44%. The company has invested heavily in the project since acquisition in early 2017. **This spend has not been matched proportionally by SNPC which now owes AAOG between US$8 – 10 million** – a decent proportion of the current market cap we point out. **In light of this fact, there would look to be an opportunity for the company to exchange this debt for an increased stake in the project. Such a move could take AAOG's stake to 85%, which is the maximum legally available in the Republic of the Congo. Reading between the lines, it would seem that the government want the company to have a larger stake and this might well all come about when the licence is renewed in 2020.**

However, the opportunity for AAOG could be far larger. Following the drilling successes in R1/R2 and Mengo, the TLP-103C well is now going deeper in search of the Djeno, which has been a producing horizon in the neighbouring fields for a number of years. This represents pure exploration drilling and Djeno is a big prize as it has prolific oil flow rates, driven by lower lying high-pressure gas. A natural flow rate of 5,000 bopd per well is expected by analogy with the wells in Total's acreage. AAOG's technical work and the data from these analogous wells give confidence that the presence of hydrocarbons in the Djeno Sands is probable. **Such a success would be transformational for the company.**

It might be that AAOG does not penetrate Djeno first time, but the knowledge gained will improve the chances for the next well TLP-104 which is expected to be drilled back to back with TLP-103. Once both TLP-101 and TLP-102 are in production and TLP-103 has been drilled in its entirety, AAOG looks like it is set to become highly profitable from R1/R2 and Mengo alone. **If also producing from Djeno, then the change in value of AAOG could be exponential. Moving ahead, additional seismic and data interpretation will be required in order to formulate the field development plan**.

The investment case for AAOG seems to be becoming more and more compelling for a number of reasons. Firstly, the company has a producing asset with significant appraisal and exploration potential which is only just really starting to become properly appreciated. Secondly, the team are in the midst of what, by oil industry standards, is a low-cost programme which realistically has the potential to increase production to in excess of 5,000 bopd or more. Thirdly, judging by the successes enjoyed in the same reservoirs in adjacent fields, the company is sitting pretty with a licence in a plum location. Lastly, management has plenty of West African oil experience to make every success of the opportunity, AAOG brings with it a private equity-style focus on costs, cash flows and dividends. **There is no doubt that managements' interests are well-aligned with those of shareholders. This is well-demonstrated by executive compensation being composed of part deferred salary and options. Share options at 20p will only be granted when the company hits the ambitious sustained production targets of 1,000, 2,500 and 5,000 bopd. Success at Mengo and potentially also Denjo looks as though it will create a potentially high level of earnings and profitability. This would allow the Board to deliver on its promise of distributing significant dividends to shareholders.**

AAOG provides an appealing mix of a producing asset with both development potential and exploration upside. Low-risk development potential is expected to result from increased production from the existing horizon (R1/R2) and bringing the proven Mengo horizon into production. At the same time, there is also high upside exploration potential from what could be a transformational increase in production through exploration into the deeper Denjo horizon. The team's interests are strongly aligned with those of shareholders as management's remuneration is tied to meeting ambitious production growth targets.

We believe that the announced success at Mengo could actually really be the game changer for AAOG. Whatever happens now, the company has been given the opportunity to become nicely cash flow generative. In the future, it will be a lot easier to finance new wells. Moving ahead, every well that AAOG drill here is going to target Djeno, such is the size of the prize. If they don't hit it in the right place then the well can be completed below the Mengo. The word is that engineers from SNPC have looked at the data and believe that the Tilapia Mengo discovery is just the same as every other Mengo well that they have brought into production. Investors might be disappointed that so far there have been no flow rates announced, but that is just not possible yet when drilling a multi-horizon well.

There is no doubt that AAOG is shaping up to be a profitable company, even ahead of the deeper drilling and the bigger prize that lies below in the Djeno horizon. The company is a very different animal from the normal small oil and gas companies who live or die on their success with the drill bit, as AAOG has existing production. Unlike other small oilers, where a decent discovery would require millions of dollar of capital expenditure and a long wait before any oil can be sold, AAOG benefits from having existing topside infrastructure which means that the team can very quickly turn confirmed resources into production.

It does look as though there will be no let-up in the good newsflow we have seen over recent months. **Over the coming months, there will be news from the drilling with Djeno itself, flow testing & completion and licence renewal. The geological model looks good and experts can see the Djeno on the model**. It is thought that the updated reserve estimate in Q1 2019 looks high likely to make for good reading and allow a renewed valuation to be placed on the company's oil and gas interest. All this will be happening as the team is also working on other assets**. So, to us, AAOG bears all the hallmarks of becoming one of the oil and gas success stories of 2019.**

Financials & current trading

Losses that have been recorded over recent years are mainly due to administration expenses as the company has only recently begun to generate cash flow following the successful work over on both the existing wells, TLP-101 and TLP-102.

Year end 31 December £'000s	2015A	2016A	2017A
Revenue	-	-	227
Pre-tax profit/(loss)	(120)	(937)	(3,141)
Net profit/(loss)	(113)	(937)	(2,926)

AAOG three-year trading history. Source: Company accounts

2017 results

This period saw the first cashflow from Tilapia. Revenue was £0.227 million which after £0.405 million in cost of sales led to a loss of £0.179 million. The loss from operating activities came out at £3.087 million after £2.77 million of administrative expenses and £0.138 million of share-based payment charges. The pre-tax loss came out at £3.141 million, with a total comprehensive loss for the year of £2.926 million which gave rise to a basic and diluted loss per share of 5.75p.

2018 interim results

Interim results for the six months to 30th June 2017, reported on a period which saw the build up to the drilling of the new well TLP-103C. During this period revenue was £0.106 million and cost of sales of £0.385 million, which resulted in a gross loss of £0.279 million. After £1.605 million of administration expenses and £0.154 million of share-based payment charges, the operating loss came out at £2.038 million. Adding £0.133 million of fundraising costs led to a loss from operating activities of £2.171 million and a total comprehensive loss of £2.213 million, which equated to a basic and diluted loss per share of 2.71p.

Recent developments

TLP-103C was spudded on 8th October 2018 at a newly constructed pad which was 95m NW of TLP-103. In late-October 2018, AAOG provided the news that a conditional £5 million Convertible Loan Note Financing Facility had been entered into with Sandabel Capital L.P. At this time, the company also reported that an option had been secured to keep the current rig SMP-102 onsite at Tilapia to drill a potential further well, TLP-104, which would represent well number two in a six-well development plan, resulting in significant mobilisation and demobilisation cost savings,

Late-December 2018 brought the news that TLP-103C had intersected the Mengo horizon and that hydrocarbons were encountered. The top of the Mengo was picked at 1,856m and formed of interbedded sandstones and claystones. This was in line with the company's geological model. In addition, the top of the Marnes de Pointe Noire, underlying the Mengo, was picked at 1,960m and formed of dark claystones.

Early January 2019 saw AAOG able to announce that wireline logging by Schlumberger had confirmed a combined 44 metres of oil columns across multiple horizons at the TLP-103C well. Included in those numbers is the discovery of additional reservoirs. This news was followed by a placing which raised £6 million at 10p to mainly cover costs on the TLP-103C, replacing the Sandabel facility which had been cancelled following this fund raising exercise.

Risks

Geological risks

There are a series of technical risk factors concerning the amount of understanding of the geology of the project areas, the reservoirs being targeted and the distribution and magnitude of the indicators that have been identified in exploration work.

Political risk

There are political risks involved in companies operating in The Republic of the Congo. The oil industry is arguably the most susceptible sector of the market to political risks largely due to the its importance to the host county's economy.

Oil price risks

Oil prices are highly cyclical and changes in the price could have a negative or positive impact on the valuation of the company's projects and revenue from the sales of hydrocarbons. Over the past decade, the price of oil has been highly volatile, trading in the range of US$140 to US$28. Currently, Brent crude trades around the US$61 level.

Exchange rate risks

Movements in the value of currencies will have an effect on the company's accounts on translation from US dollars of oil revenues, US dollar payments to contractors and local costs in Central African CFA francs into sterling. Fluctuations in the value of the US dollar and the Central African CFA franc against the pound may have an effect on the valuation that AAOG is awarded by the UK stock market.

Future funds

The market for raising funds for small cap companies may have improved from the worse conditions seen for resources stocks two years ago, however the equity market does continue to be difficult. Some recent fundraisings in the oil sector have seen share prices being undermined by incoming investors demanding substantial discounts to provide the necessary capital.

Board of Directors

David Sefton – Chairman

David has extensive experience within the oil and gas industry, across Europe, Russia, the Middle East and North America. He has worked with many of the world's leading international and national oil companies and is Managing Partner of Linton Capital LLP, a private equity manager. David completed undergraduate and postgraduate studies at the University of Oxford and qualified as a barrister. He worked for Cleary Gottlieb, Steen & Hamilton before becoming Chief Legal Officer for the international acquisition arm of LukOil.

James Berwick – Chief Executive Officer

Between 2013 and 2018, James held the board-level position of Commercial Director of Impact, during which he oversaw a significant expansion of the company's activities, including the acquisition of six assets. He was also instrumental in securing farm-out agreements with operators including Exxon, Statoil, Woodside, CNOOC and Total.

At Ophir, James was Director of New Business (2006 - 2013) with responsibility for scaling up and managing the company's portfolio ahead of its successful IPO in 2011. As well as overseeing every commercial transaction completed during this period, he was also responsible for successfully de-risking Ophir's asset base within the constraints of available capex. James previously held the role of General Manager for Gabon where Ophir drilled several wells under his supervision and he managed the company's operated assets throughout Africa, including Marine IX in the Republic of the Congo. Over the course of his career, during which he was also Head of Global Security and Risk at Woodside Energy, James has built up an extensive network of contacts within Africa and the oil and gas sector, including with super-majors, governments and leading industry advisers.

Before his career in the oil and gas industry, James served for 12 years in the British Army and the French Foreign Legion.

James Cain – Finance

James is a Fellow of the Institute of Chartered Accountants in England and Wales and has been both Finance Director and Chief Executive in listed and private-equity backed businesses. He is currently Finance Director of KCR Residential REIT plc as well as CFO of Linton Capital LLP.

Brian Moritz - Non-Executive Director

Brian is a former Senior Partner of Grant Thornton, London. He formed Grant Thornton's Capital Markets team which floated over 100 companies on AIM during his chairmanship. Since retiring from Grant Thornton in 2004, he has concentrated on assisting new companies with accessing the capital markets, especially those in the mining and resources sector. He is a Fellow of the Institute of Chartered Accountants in England and Wales.

Phil Beck - Non-Executive Director

Phil is a senior energy industry business consultant with more than 40 years' commercial, engineering and project management experience in upstream oil and gas industry. He is a trained geologist and petroleum engineer who spent his early career with British Gas and Unocal Corporation. Phil has been a management consultant for the last sixteen years and during which time he has been responsible for proving a significant growth in value to many energy businesses.

Nick Butler - Non-Executive Director

Nick is the founding Chairman of the Policy Institute at King's College London, which links academic work to policy-makers in the UK and across Europe. Since May 2010, he has held the post of Visiting Professor at King's College London and is currently the external adviser and reviewer of the World Energy Outlook - the flagship publication of the International Energy Agency. In addition, Nick is a member of the Strategic Advisory Council of Statoil, the Norwegian state-controlled energy company and serves on the Advisory Council Centre for Ecology and Hydrology - an independent agency wholly owned by the UK Government. Between 2009 and 2010, he was Senior Policy Adviser to Gordon Brown, then UK Prime Minister, specialising in business policy and the stabilisation of the UK economy after the 2008 financial crash. Between 2007 and 2009, Nick served as Chairman of the Cambridge Centre for Energy Studies based at the Judge Business School, University of Cambridge.

Prior to his economic consultancy work, Nick held several senior positions at BP including Group Vice-President for Strategy and Policy Development, advising the Chief Executive and the Executive Committee on climate change, mergers and acquisitions, organisational change and major new ventures; Group Policy Adviser to the Chief Executive on all aspects of policy; Head of External Affairs, responsible for the company's links with stakeholders, including NGOs, the financial community, investors, the media and Government; and Head of Investor Relations for upstream exploration and production.

Sarah Cope - Non-Executive Director

Sarah has more than 20 years' experience as an investment banker in London, advising small and mid-sized companies at Board level on corporate governance, growth strategy, acquisitions and disposals, capital markets and regulatory compliance. Over the last 10 years, she has specialised in the oil and gas sector, helping listed oil and gas companies raise finance for exploration, development and production at projects around the world. Her most recent role was with Cantor Fitzgerald Europe, the global investment bank and brokerage business, where she was until very recently Managing Director and Co-Head of Energy. Prior to this, Sarah was Head of Oil & Gas at RFC Ambrian and at FinnCap. She has also been Director of Equity Capital Markets at RBC Capital Markets and Director of Corporate Finance at Seymour Pierce.

Forecasts

We initiate coverage of AAOG with financial forecasts for the years ending 31st December 2018 and 2019. For 2018 there was intermittent oil production from the R1/R2 reservoir at Tilapia. The pre-tax loss is determined to be £3.664 million and the loss per share is calculated to be 3.01p.

For 2019, oil revenue is expected to climb to £6.9 million due to an increased level of sustained production at the R1/R2 reservoir along with the first production from the Mengo reservoir where it is expected that two wells could be in production by the year-end. **There has been no contribution from the Djeno reservoir incorporated in this forecast for 2019.** AAOG's share of oil revenue has been determined based on the company's current 56% stake in the project. The cost of sales in this developmental phase is seen to be higher on a per barrel basis than is projected over the longer timeframe. **A pre-tax profit of £1.6 million is forecast for the year which we believe would equate to earnings per share of** 0.69p.

Year End 31 December (£000's)	FY2016a	FY 2017a	FY 2018e	FY 2019e
Continuing operations				
Revenue	-	227	200	6,900
Cost of sales	-	(405)	(500)	(1,800)
	-	(179)	(300)	5,100
Administrative expenses	(932)	(2,770)	(3,200)	(3,200)
Share-based payment charges	-	(138)	(154)	(300)
Profit/(loss) from operating activities	(932)	(3,087)	(3,654)	1,600
Finance income	-	8	-	-
Finance costs	(5)	(63)	(10)	-
Profit/(loss) before tax	(937)	(3,141)	(3,664)	1,600
Taxation	-	-	-	-
Loss for the year from operating activities	(937)	(3,141)	(3,664)	1,600
Exchange translation on foreign operations	-	216	(65)	-
Total comprehensive profit/(loss) for the year	**(937)**	**(2,926)**	**(3,729)**	**1,600**
Profit/(loss) per ordinary share (pence)				
Basic and diluted	(2.21)	(5.75)	(3.01)	0.69
Weighted average number of shares	42,418,932	50,901,726	123,793,543	233,383,583
Total shares plus warrants and options	42,418,932	69,504,565	177,929,038	233,383,583

Source: Company/Align Research

Valuation

AAOG lies at an important stage in its short history as a quoted company. After the successes and discoveries that have already been reported from TLP-103C, the well is now being drilled deeper, targeting the Djeno which is seen as the bigger prize. The TLP-103C well was designed to target the R1/R2 producing reservoirs plus an 8.1 million barrel contingent resource discovery in the lower Mengo sands, as well as testing the deeper prospect in the Djeno interval that has been assigned 58.4 mmbbls of gross prospective resources. **We have sought to place a value on the company as it stands today and intend to review our model and our target price once the drilling of the well has been completed.**

We have set about developing a financial model which is largely based on the company's current model and also on discussions with management**. It has to be pointed out that the company's current model is not at all aggressive and does not show too quick an increase in production. This has all been reflected in our own analysis**. Our model has been backed up with data from the CPR dated October 2016. As always, our approach has been from a conservative stand point, as with targets like Djeno (considering the impressive flow rates seen in neighboring fields) it's not too hard to determine some high numbers. Below we set out some of the broader assumptions on which our financial model is based, ahead of the assumptions for oil production at the three horizons.

Oil price – Oil produced is sweet crude with an API of 39-41°, which attracts a small premium to Brent. We use a flat price for Brent crude of US$65 per barrel over the life of the project and have assumed that the partners will gain a 3% premium over Brent over this period.

Production sharing agreement - PK and SNPC signed the original PSA with the Republic of Congo in December 2005 and in January 2015 this agreement was extended for a five-year period. The current term expires in December 2020 and a new licence for 5 of 10-year periods is assumed to be available from December 2020 on lodging an agreed field-development plan with its partner SNPC. The gross oil revenue is revenue is subject to a 15% royalty and the remaining 85% is split into Cost Oil and Profit Oil, with the share due to AAOG determined by the level of cumulative oil production over the life of the PSA.

Cumulative Oil (mmbbls)	Cost Oil (%)	Profit Oil (%	Contractor share of Profit Oil (%)	Government share of Profit Oil (%)
0-1	70	30	70	30
1-5	60	40	60	40
5-25	55	45	55	45
>25	50	50	50	50

PSA fiscal terms. Source: LR Energy CPR in AIM admission document & Company

Operating costs – The CPR set out operating costs at the project across the various reservoirs which were composed of a variable US$4.12 per barrel plus a fixed component of US$62,500 per annum. These figures provided useful guidance for the operating costs for not only the R1/R2 horizon, but also the Mengo and Djeno horizons.

R1/R2

Although the latest news is that experts believe that a waterflood could potentially boost production from the R1/R2 to 400 bopd, with TLP-101 being the producer and TLP-102 being the injector, we have looked at a more conservative project that is in line with the suggestions discussed in the CPR.

In our model, oil production is seen to increase over the next three years to reach a plateau of 250 bopd which is maintained until 2035, followed by a decline rate of around 15%. Looking at the period until 2050, the cumulative total of oil produced from R1/R2 would be 1.95 mmbbls. We expect that could be achieved by regular workovers of the existing wells.

Mengo

Cash flow was determined for the Mengo based on the best (P50) estimate of contingent resources of 8.1 mmbbls. The CPR determined that 4.4 wells would be required to drain the field. So, a total of 5 producing wells in total were assumed which would need to be drilled at a capital cost of US$3.5 million per well over the next two years or so with first production in 2019.

Oil production was modelled over a twenty-year period, peaking at an average rate of around 2,200 bopd in 2022 before declining initially at a rate of 15% and then slowing down to a 10% decline over the remainder of the period under study.

Djeno

Modelling of oil production from the Djeno was based on the best (P50) estimate of the prospective resources of 15.9 mmbbls. Work by the consultants in the CPR had recommended that 3.8 wells would be needed to drain the reservoir. Our model used four producing wells which were assumed to be drilled within a two-year period at a cost of US$4 million per well.

We have remained quite conservative with production rates and modelled oil production over a twenty-year period with average oil production peaking at 6,300 bopd in 2021 followed by a decline of 20% in the initial years then a 15% decline rate. Additional investment would be required on the topside at Tilapia to cope with this level of production and so there is an additional US$16 million allowance for facilities and engineering which would cover the additional storage requirements and the cost of a pipeline to the refinery which is 17km away.

The success of TLP-103C already looks likely to have put the company firmly on a course towards becoming significantly cash flow positive. This means that the cost of drilling the wells targeting production from the Mengo and the Djeno could be met largely out of internally generated funds on the timescale that we have set out. However, a rising stock price is likely to be used by the board as an opportunity to raise further equity funds which would all allow the production schedule to be accelerated. **This is a move which would probably be applauded by the market as this would serve to improve the NAV.**

Truth is that following the success to date of the TLP-103C well, any new well is likely to be targeting the Djeno at first as it is such a big prize. If any such well does not hit the Djeno, then it can simply be completed to extract oil from the Mengo.

The results of our analysis are shown below. We determined net asset valuations using a 10% and a 12% discount factor, which were then risked by taking account of both the geological chance of success and the commercial chance of success as set out in the CPR.

Net Asset Valuation	Net WI reserves mmboe	Unrisked NPV(10) US$m	Geological Chance of Success	Commercial Chance of Success	Dry hole cost US$m	Risked NPV(10) per share (p)
Net cash/(debt)		1.7				0.55
Placing (net)		7.0				2.28
G&A costs		(13.3)				(4.33)
Tilapia – R1/R2	1.1	14.72	100%	100%	0	4.80
1P – Core value						**3.30**
Discovered/Undeveloped reserves						
Tilapia– Mengo (Best)	4.7	73.72	60%	100%	2.4	14.10
2P Core + discovered value						**17.40**
Visible Exploration						
Tilapia – Djeno (Best)	9.0	174.51	25%	100%	4.8	13.04
3P Core + discovered + visible exploration value						**30.44**

Net Asset Valuation using a 10% discount factor based on 237.9 million shares on a fully diluted basis and current FX rate. Source: Align Research

Net Asset Valuation	Net WI reserves mmboe	Unrisked NPV(12) US$m	Geological Chance of Success	Commercial Chance of Success	Dry hole cost US$m	Risked NPV(12) per share (p)
Net cash/(debt)		1.7				0.55
Placing (net)		7.0				2.28
G&A costs		(11.8)				(3.85)
Tilapia – R1/R2	1.1	13.03	100%	100%	0	4.25
1P – Core value						**3.23**
Discovered/Undeveloped reserves						
Tilapia– Mengo (Best)	4.7	67.26	60%	100%	2.4	12.84
2P Core + discovered value						**16.07**
Visible Exploration						
Tilapia – Djeno (Best)	9.0	163.65	25%	100%	4.8	12.16
3P Core + discovered + visible exploration value						**28.23**

Net Asset Valuation using a 12% discount factor based on 237.9 million shares on a fully diluted basis and current FX rate. Source: Align Research

We believe that this analysis clearly shows the robust value that sits behind AAOG. Both these NAV calculations were based on the current number of shares in issue. At a 10% discount rate the risked NAV equates to 30.44p per share. **We have chosen to use the higher risked NAV using a 12% discount rate to determine a risked NAV of 28.23p per share which we have elected to use as our target price.** We note that there is a management incentive scheme in place which could see a total of 9,076,479 options exercisable at 20p being vested (where a third of these options is vested when production climbs over 1,000, 2,500 and 5,000 bopd hurdles in a sustained fashion) which would only dilute the risked NAV by 3-4%.

Conclusion

In our view, AAOG now presents the rare potential of a highly profitable small cap oil company to buy into where, most importantly to us, management are properly aligned with investors. The producing assets offer compelling development potential plus explosive exploration upside.

Our analysis, we add, was based on AAOG's current interest in Tilapia of 56%. We realise that there is a real likelihood that the company may be able to swap SNPC's debt of now US$8-10 million for an increased stake in the project. Such a move could clearly have a very beneficial effect on the valuation that we have determined. It is not beyond the bounds of possibility that AAOG could end up with an 85% stake in Tilapia, which is the maximum allowed in the Republic of Congo. **This would add c.50% to our risked NAV figures and target price.**

At the same time, it is looking like a good time for AAOG to be negotiating a new PSA. The existing PSA terms are not really that good and could be improved measurably. The Republic of the Congo wants to do a licensing round in the next year and although it might have the likes of Eni and TOTAL interested in the big deepwater plays, truth is that there are not a lot of the small/medium sized players like AAOG active over there. The government needs to attract players of this size to show an interest in the smaller and more marginal oil fields. The company also seems to have the backing of the Oil Minister and given the current environment, the minister probably does not want to alienate AAOG. **All of this means that the stage might be set for really meaningful negotiations which result in the company gaining a beneficial improvement in the terms of the PSA**. Patently, should this come to pass then this will provide further incremental upside to the risked NAV.

We look forward to updating our target price as there becomes more clarity over the scale of the potential upside at Tilapia and point out that at the current stock price of 10.35p the discovered wells at Tilapia cover the stock price by near a factor of 1.6 times on our analysis using very conservative inputs.

Our coverage of AAOG is thus initiated with a first target price of 28.23p and a Conviction Buy stance.

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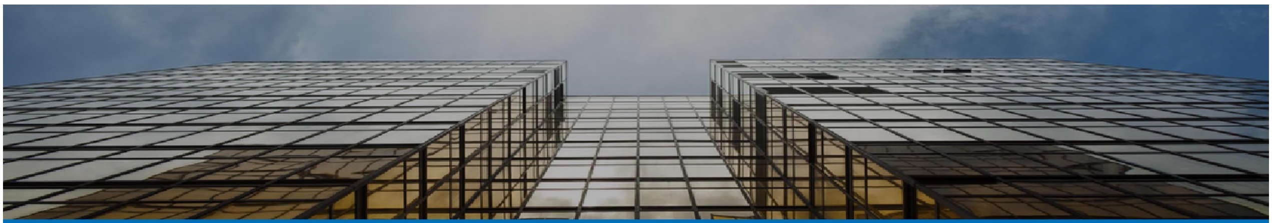

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