Africa Oil Corp.

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ANNUAL INFORMATION FORM

For the Year
Ended December 31, 2015

February 26, 2016

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GLOSSARY OF TERMS

"10BA Farmout Agreement" means the Farmout Agreement made September 27, 2010 between Centric Energy (Kenya) Limited and Tullow Kenya B.V., in respect of the PSC covering Block 10BA, Kenya.

"12A/13T Farmout Agreement" means the Farmout Agreement made January 26, 2011 between, among others, the Company and Tullow Kenya B.V., in respect of the PSCs covering Block 12A and Block 13T, Kenya.

"2D" means two dimensional.

"3D" means three dimensional.

"Africa Energy" means Africa Energy Corp.

"Africa Oil" "AOC" "Company" or the **"Corporation"** means Africa Oil Corp., including Africa Oil and its subsidiaries.

"Agriterra" means Agriterra Limited (formerly White Nile Ltd.)

"Agriterra Farmout Agreement" means the Farmout Agreement made June 14, 2010 between AOEBV and Agriterra, in respect of the South Omo Block in Ethiopia.

"AIF" or **"Annual Information Form"** means this Annual Information Form prepared for the year ended December 31, 2015 and dated February 26, 2016.

"AOEBV" means Africa Oil Ethiopia B.V.

"API" means American Petroleum Institute.

"BCBCA" means the *Business Corporations Act* (British Columbia) S.B.C. 2002 c.57, as amended, including the regulations promulgated thereunder.

"Canmex I" means Canmex Holdings (Bermuda) I Ltd.

"Centric" means Centric Energy Corp.

"Centric Arrangement Agreement" means the Arrangement Agreement dated as of November 29, 2010, as amended by Amending Agreements dated December 23, 2010 and January 4, 2011, between the Company and Centric, including the disclosure letters of Centric and the Company.

"Centric Plan of Arrangement" means the arrangement completed pursuant to the provisions of Part 9, Division 5 of the BCBCA in accordance with the terms and conditions set forth in the Plan of Arrangement attached as Schedule A to the Centric Arrangement Agreement pursuant to which the Company acquired all of the issued and outstanding shares of Centric on the basis of 0.3077 shares of the Company and $0.0001 in cash for each one share of Centric.

"**commercial discovery**" means a discovery that is potentially commercial when taking into account all technical, operational, commercial and financial data collected when carrying out appraisal work or similar operations, including recoverable reserves of petroleum, sustainable regular production levels and other material technical, operational, commercial and financial parameters, all in accordance with prudent international petroleum industry practices.

"**common shares**" means the common shares in the capital of the Company.

"**Contractor Group**" means the parties, including joint venture partners, that hold a working interest in a PSA or a PSC.

"**crude oil**" means a mixture that consists mainly of pentanes and heavier hydrocarbons, which may contain sulphur and other non-hydrocarbon compounds, that is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated. It does not include solution gas or natural gas liquids.

"Delonex" means Delonex Energy Limited.

"**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs or support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

"**development well**" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive;

"**EAX**" means East African Exploration Limited, a wholly-owned subsidiary of Black Marlin Energy Holdings Limited. Black Marlin Energy Holdings Limited was acquired by Afren plc on October 7, 2010.

"Ethiopian Government" means the Government of the Federal Democratic Republic of Ethiopia.

"EWT" means extended well testing.

"First North" means the First North exchange at Nasdaq Stockholm.

"**Farmout Agreement**" means a contractual agreement between parties whereby the holder of an interest in an oil and gas concession agrees to assign all or part of that interest to another entity in exchange for fulfilling contractually specified conditions.

"**gross**" means:

(a) in relation to wells, the total number of wells in which the Company has an interest; and

(b) in relation to properties, the total area of properties in which the Company has an interest.

"**IFC**" means International Finance Corporation.

"Kenyan Government" means the Government of the Republic of Kenya.

"Maersk" means Maersk Olie og Gas A/S, a Danish oil and gas company owned by the Maersk Group.

"Marathon" means Marathon Oil Corporation.

"MD&A" means Management's Discussion and Analysis of results of operations and financial condition of the Company for the period ended December 31, 2015 dated February 26, 2016.

"**Nasdaq Stockholm**" means the Nasdaq Stockholm exchange.

"**natural gas**" means all gaseous petroleum and inerts.

"**net**" means:

(a) in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and

(b) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

"New Age" means New Age (African Global Energy) Limited.

"**operating costs**" mean costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

"**NI 51-101**" means the National Instrument 51-101 — *Standard of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators and the companion policies and forms thereto, as amended from time to time.

"NI 52-110" means the National Instrument 52-110 – *Audit Committees* of the Canadian Securities Administrators and the companion policies and forms thereto, as amended from time to time.

"**petroleum**" means: (i) any naturally occurring hydrocarbons in gaseous or liquid state; (ii) any mixture of naturally occurring hydrocarbons in gaseous or liquid state; or (iii) any petroleum (as defined in (i) or (ii) above) that has been returned to a reservoir.

"**petroleum operations**" means all exploration, gas marketing, development, production and decommissioning operations, as well as any other activities or operations directly or indirectly related or connected with said operations (including health, safety and environmental operations and activities) and authorized or contemplated by, or performed in accordance with PSC's.

"Platform" means Platform Resources Inc.

"**production**" means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.

"**PSC**", "**PSA**", "**Production Sharing Contract**" or "**Production Sharing Agreement**" means contracts or agreements entered into with a host government providing for petroleum operations in a defined area and the division of petroleum production from the petroleum operations.

"**Profit Oil**" means the amount of production, after deducting cost oil production allocated to costs and expenses that would be divided between the participating parties and the host government under a Production Sharing Contract.

"**prospect**" means a project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.

"**prospective resources**" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development.

"Rift Basin Area PSA" means the PSA made February 21, 2013 between AOEBV and the Ethiopian government.

"SEDAR" means the Canadian Securities Administrator's System for Electronic Document Analysis and Retrieval.

"TSX" means the Toronto Stock Exchange.

"Tullow" means Tullow Oil plc .

"Tullow Farmout Agreement" means the Farmout Agreement made September 1, 2010 between, among others, the Company, Tullow Kenya B.V. and Tullow Ethiopia B.V., in respect of the PSAs covering Blocks 10A and 10BB, Kenya and the South Omo Block, Ethiopia.

"**working interest**" means a percentage of the ownership in an oil and gas concession granting its owner the right to explore and develop oil and gas from a specific property which normally bears its proportionate share of the costs of exploration, development and operations as well as any royalties or other production burdens.

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CURRENCY

The Company's functional and reporting currency is the United States dollar. All currency amounts in this AIF are expressed in United States dollars, unless otherwise indicated. The Bank of Canada exchange rates for the purchase of one United States dollar with Canadian dollars for the specified year ends are as follows:

	Year Ended December 31		
Bank of Canada Noon Exchange Rate:	**2013**	**2014**	**2015**
USD$/CAD$	1.0636	1.1601	1.384

ACCOUNTING POLICIES AND FINANCIAL INFORMATION

Financial information contained in this AIF is presented in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

ABBREVIATIONS

Oil and Natural Gas Liquids		**Natural Gas**	
Bbls	Barrels of crude oil	Mcf	Thousand cubic feet of natural gas
Bbls/d	Barrels of crude oil per day	MMcf	Million cubic feet of natural gas
Boe	Barrels of oil equivalent	Bcf	Billion cubic feet of natural gas
Bopd	Barrels of oil per day	Mcfd	Thousand cubic feet of natural gas per day
Boepd	Barrels of oil equivalent per day	Mcfe	Thousand cubic feet of gas equivalent
Mbbl	Thousands of barrels of crude oil	MMbtu	Million British Thermal Units
NGLs	Natural gas liquids		

Note: The calculations of barrels of oil equivalent (boe) and thousand cubic feet of gas equivalent (Mcfe) are based on the standard of 6Mcf: 1 bbl when converting natural gas to oil and 1 bbl: 6 Mcf when converting oil to natural gas. Boe and Mcfe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1 bbl or a Mcfe conversion ratio of 1 bbl: 6 Mcf is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

CONVERSION TABLE

The following table sets forth certain conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	**To**	**Multiply By**
Mcf	Cubic meters	28.174
Cubic meters	Cubic feet	35.315
Bbls	Cubic meters	0.159
Cubic meters	Bbls	6.289
Feet	Meters	0.305
Meters	Feet	3.281
Miles	Kilometers	1.609
Kilometers	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471
Gigajoules	MMbtu	0.950
MMbtu	Gigajoules	1.0526

PRESENTATION OF OIL AND GAS INFORMATION

All oil and gas information contained in this AIF has been prepared and presented in accordance with NI 51-101. The actual oil and gas resources may be greater or less than any estimates provided herein.

FORWARD LOOKING STATEMENTS

Certain statements in this document are “forward-looking statements”. Forward-looking statements are statements that are not historical fact and are generally identified by words such as “believes”, “anticipates”, “expects”, “estimates”, “pending”, “intends”, “plans”, “will”, “would have” or similar words suggesting future outcomes. By their nature, forward-looking statements and information involve assumptions, inherent risks and uncertainties, many of which are difficult to predict, and are usually beyond the control of management, that could cause actual results to be materially different from those expressed by these forward-looking statements and information. Risks and uncertainties include, but are not limited to, risk with respect to general economic conditions, regulations and taxes, civil unrest, corporate restructuring and related costs, capital and operating expenses, pricing and availability of financing and currency exchange rate fluctuations. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements.

The Company does not undertake to update or re-issue the forward-looking statements and information that may be contained herein, whether as a result of new information, future events or otherwise.

Any statements regarding the following are forward-looking statements:

- expected closing dates for the completion of proposed transactions;
- planned exploration, appraisal and development activity including both expected drilling and geological and geophysical related activities;
- future development costs and the funding thereof;
- anticipated future financing requirements;
- future crude oil, natural gas or chemical prices;
- future sources of funding for our capital program;
- availability of potential farmout partners;
- government or other regulatory consent for exploration, development, farmout, or acquisition activities;
- future production levels;
- future capital expenditures and their allocation to exploration and development activities;
- future earnings;
- future asset acquisitions or dispositions;
- future debt levels;
- availability of committed credit facilities;
- possible commerciality;
- development plans or capacity expansions;
- future ability to execute dispositions of assets or businesses;
- future sources of liquidity, cash flows and their uses;
- future drilling of new wells;
- ultimate recoverability of current and long-term assets;
- ultimate recoverability of reserves or resources;
- expected finding and development costs;
- expected operating costs;
- estimates on a per share basis;
- future foreign currency exchange rates;
- future market interest rates;
- future expenditures and future allowances relating to environmental matters;
- dates by which certain areas will be explored or developed or will come on stream or reach expected operating capacity; and
- changes in any of the foregoing.

Statements relating to “reserves” or “resources” are forward-looking statements, as they involve the implied assessment, based on estimates and assumptions that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future.

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others:

- market prices for oil and gas and chemical products;
- our ability to explore, develop, produce and transport crude oil and natural gas to markets;
- production and development costs and capital expenditures;
- the imprecision of reserve estimates and estimates of recoverable quantities of oil, natural gas and liquids;
- ultimate effectiveness of design or design modification to facilities;
- the results of exploration, appraisal and development drilling and related activities;
- short term well test results on exploration and appraisal wells do not necessarily indicated the long term performance or ultimate recovery that may be expected from a well;
- pipeline or delivery constraints;
- volatility in energy trading markets;
- incorrect assessments of value when making acquisitions;
- foreign-currency exchange rates;
- economic conditions in the countries and regions in which we carry on business;
- governmental actions including changes to taxes or royalties, changes in environmental and other laws and regulations;
- renegotiations of contracts;
- results of litigation, arbitration or regulatory proceedings;
- political uncertainty, including actions by terrorists, insurgent or other groups, or other armed conflict; and
- internal conflicts within states or regions.

The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these factors are interdependent, and management’s future course of action would depend on our assessment of all information at that time. Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity and achievements.

Undue reliance should not be placed on the statements contained herein, which are made as of the date hereof and, except as required by law, we undertake no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

CAUTIONARY STATEMENTS REGARDING WELL TEST RESULTS

Drill stem tests are commonly based on flow periods of 1 to 5 days and build up periods of 1 to 3 days. Pressure transient analysis has not been carried out on all well tests and the results should therefore be considered as preliminary. Well test results are not necessarily indicative of long-term performance or of ultimate recovery.

ITEM 1 INTRODUCTION

INCORPORATION BY REFERENCE AND DATE OF INFORMATION

Specifically incorporated by reference and forming a part of this AIF are the Company's material change reports from January 1, 2015 to the date of this AIF, copies of which have been filed with the Canadian Securities Administrators in each of the Provinces of British Columbia, Alberta, and Ontario and can be found on the SEDAR website at www.sedar.com under the Company's profile.

All information contained in this AIF is as of December 31, 2015, unless otherwise indicated.

ITEM 2 CORPORATE STRUCTURE

INCORPORATION AND REGISTERED OFFICE

Africa Oil Corp. was incorporated under the BCBCA on March 29, 1993 under the name "Canmex Minerals Corporation" with an authorized capital of 100,000,000 common shares. On July 2, 1999 the issued and outstanding shares of the Company were consolidated on a one-for-five basis and the authorized capital was increased, post-consolidation to 100,000,000 common shares. On August 20, 2007 the Company changed its name to Africa Oil Corp. On June 19, 2009 the shareholders of AOC passed a special resolution increasing the Company's authorized share capital to an unlimited number of common shares. On June 3, 2013, the shareholders of AOC passed a special resolution authorization an alteration of the Company's articles to include advance notice provisions for the nomination of directors.

Africa Oil's registered and records office is located at Suite 2600 Oceanic Plaza, 1066 West Hastings Street, Vancouver, British Columbia, V6E 3X1. The Company's corporate office is located at 2000 – 885 West Georgia Street, Vancouver, B.C. V6C 3E8. The Company also has an office located at 1750, 300 – 5th Avenue SW, Calgary, AB, Canada T2P 3C4.

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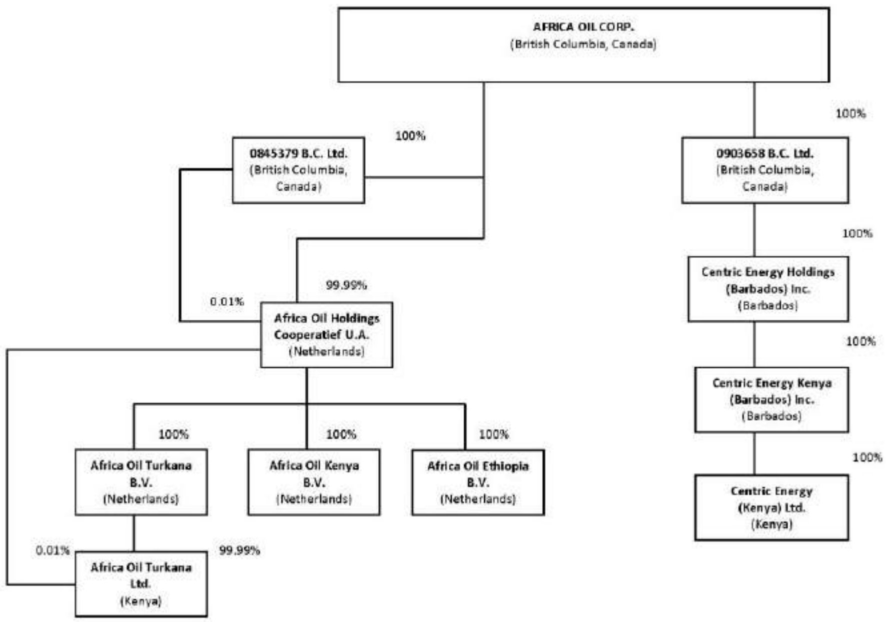
INTER-CORPORATE RELATIONSHIPS

The material subsidiaries owned by Africa Oil[1], as at the date of this AIF, are as set out in the following organizational chart:



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[1] Africa Energy Corp. is no longer considered a subsidiary of the Company. Africa Oil Corp. currently owns approximately 32% of Africa Energy Corp and accounts for its share of Africa Energy as an equity investment. During 2015, the composition of Africa Energy's board of directors changed and Africa Oil's ownership interest was diluted due to equity financings completed by Africa Energy.

ITEM 3 GENERAL DEVELOPMENT OF THE BUSINESS

Africa Oil is an independent international upstream oil and gas exploration company whose head office is in Canada with oil and gas interests in Kenya and Ethiopia. The Company holds interests in exploration properties throughout several African rift basins, focusing primarily on East Africa. A summary of the Company's current partnership interests is set out in the following table:

Country	Concession	Gross Acreage (km^2)	Working Interests[(1)]	
Kenya	10BA[(2)]	15,811	AOC Maersk Tullow (Operator)	25% 25% 50%
	10BB[(2)]	6,172	AOC Maersk Tullow (Operator)	25% 25% 50%
	9	15,782	AOC (Operator) Marathon Oil	50% 50%
	12A	15,235	AOC Tullow (Operator) Delonex Energy	20% 40% 40%
	13T[(2)]	4,719	AOC Maersk Tullow (Operator)	25% 25% 50%
Ethiopia	South Omo[(2)]	22,034	AOC Maersk Tullow (Operator) Marathon Oil	15% 15% 50% 20%
	Rift Basin Area[(3) (2)]	42,519	AOC (Operator) Maersk Marathon Oil	25% 25% 50%
	7 and 8 (Ogaden)[(3)]	21,767	AOC New Age (Operator) EAX	30% 40% 30%
	Adigala[(3)]	20,200	AOC New Age (Operator) Genel Energy plc	10% 50% 40%

[(1)] Net working interests are subject to back-in rights or carried working interests, if any, of the respective governments or national oil companies of the host governments.
[(2)] Working interest has been adjusted for the farmout agreement entered into prior to December 31, 2015 and completed prior to the preparation date of this report. Please refer to the description of the Maersk Farmout in the "Overview of Farmout and Joint Venture Agreements" section.
[(3)] During the third quarter of 2014, the Company notified the Ethiopian Government and its partners of its decision to withdraw from Blocks 7 and 8.
[(4)] During the first quarter of 2015, the Company notified the Ethiopian Government and its partners of its decision to withdraw from Adigala.

Three Year History

The following describes the development of Africa Oil's business over the last three completed financial years.

Fiscal Year Ended December 31, 2013

Significant transactions in the year

In February 2013, the Company entered into a PSA on the Rift Basin Area in Ethiopia with the Ministry of Mines, Government of Ethiopia. Under the Rift Basin Area PSA, during the initial exploration period which was originally scheduled to expire in February 2016, but has been extended to February 2017, the Company is obligated to complete geological and geophysical operations (including the acquisition of 8,000 square kilometers of full tensor gravity and 400 kilometers of 2D seismic) with a minimum gross expenditure of $5.0 million.

During October 2013, the Company completed a brokered private placement issuing an aggregate of 56,505,217 common shares at a price of 51.75 Swedish Kronas ("SEK") per common share for net proceeds of $450 million. The common shares were placed through a syndicate comprising of Citigroup Global Markets Limited, Dundee Securities Europe LLP and Pareto Securities AS, who together acted as joint bookrunners (the "Joint Bookrunners"). A cash commission equal to 3% of the gross proceeds was paid to the Joint Bookrunners.

Operational activity in the year

On the back of the successful exploration activities in Kenya during 2012, the Company, together with its partners, continued to ramp up its exploration program in Kenya and Ethiopia. Entering the year, two Tullow-Africa Oil joint venture rigs were operating in Kenya and one joint venture rig was operating in Ethiopia. Two additional Tullow-Africa Oil joint venture rigs (one of which was a testing and completion unit) were mobilized in Kenya during November 2013. The Company, as operator, and its partner in Block 9 (Kenya) secured a sixth rig, which commenced drilling operations in September 2013. In addition, the Company and its partners in Block 7/8 (Ethiopia) mobilized a seventh rig for a one well commitment, which commenced drilling operations in October 2013. The Company completed seven exploration wells and two multi-zone well tests across its blocks and exited the year with three wells drilling and one well under test.

During the first quarter of 2013, the Company and its partner, Tullow, conducted well testing operations at Twiga South-1, which resulted in a cumulative flow rate of 2,812 bopd from three zones, despite being constrained by surface equipment. With optimized production equipment, the cumulative flow rate is anticipated to have increased to a cumulative rate of approximately 5,200 bopd. High quality 37 degree API waxy sweet crude flowed from all three zones in the Auwerwer formation with good quality reservoir sands encountered. The well was suspended as a potential future production well.

Also during the first quarter of 2013, the Company and its operating partners on Block 10A completed drilling the Paipai-1 exploration well. The Paipai-1 well tested a large four-way closed structure with Cretaceous-age sandstone targets at multiple depths. Paipai-1 spudded in September 2012 and completed drilling in the first quarter of 2013 to a total depth of 4,255 meters. Light hydrocarbons were encountered while drilling a 55 meter thick gross sandstone interval. Attempts to sample the reservoir fluid were unsuccessful and the hydrocarbons encountered while drilling were not recovered to surface. The Company and its partners were unable to test the well at the time due to the unavailability, in country, of testing equipment capable of handling the higher reservoir pressures encountered at this depth.

During the second quarter of 2013, the Company completed a series of six well tests at the Ngamia-1 discovery. The cumulative flow rate from the six well tests was over 3,200 bopd constrained by completion techniques and surface equipment. With optimized completion techniques and surface equipment it is estimated that these combined flow rates would increase to a rate of 5,400 bopd. Five of the well tests were completed over the Auwerwer sandstones to verify reservoir quality and fluid content which appeared of similar quality to those tested at the Twiga South-1 well in the same basin. High quality waxy sweet crude (25-35 degrees API) was flowed from all five zones in the Auwerwer formation with good quality reservoir sands encountered. One well test was conducted in the Lower Lokhone sandstone proving it to be a productive reservoir with 30 degree API oil. All zones produced dry oil with no water produced and no pressure depletion.

As a result of testing several previously indeterminate zones in the well, net oil pay in the Ngamia-1 well doubled to over 200 meters over a gross oil column of over 1,100 meters.

Transient Pressure Analysis has been conducted on the Twiga South-1 and Ngamia-1 well tests. No pressure depletion was recorded over the duration of the tests. The Ministry of Energy agreed to a proposal by Tullow, as operator of Blocks 10BB and 13T, to carry out a combined exploration and evaluation program over a defined Area of Interest ("AOI") including all of the mapped prospects and leads along the basin bounding fault on the western edge of the Lokichar Basin. In July, the Company announced a new oil discovery at Etuko-1. Etuko-1 is located 14 kilometers east of Twiga South-1 in Block 10BB and is the first test of the Basin Flank Play in the eastern part of the discovered basin in Northern Kenya. The well encountered approximately 40 meters of net oil pay in the Auwerwer and Upper Lokhone targets and approximately 50 meters of additional potential net pay in the Lower Lokhone interval based on log analysis.

Also in July, the Company completed drilling the Sabisa-1 well in the South Omo Block. The well encountered reservoir quality sands, oil shows and heavy gas shows indicating an oil prone source rock and thick shale section which may provide a good seal for the numerous fault bounded traps identified in the basin; however, only the lowermost sands appeared to be in trapping configuration at Sabisa-1. Based on the encouragement of the results of this well, the Company decided to drill the nearby Tultule prospect next.

In September, the Company announced a new oil discovery at Ekales-1 located in the Basin Bounding Fault Play between the Ngamia-1 and Twiga South-1 discoveries. Logs indicated a potential pay zone of 60 to 100 meters to be confirmed by flow testing.

Also in September, the Company announced details of an updated independent assessment of the Company's contingent and prospective resources on its Kenyan and Ethiopian exploration properties. The effective date of this assessment was 31 July 2013 and it was carried out in accordance with the standards established by NI 51-101. Please refer to the Company's press release dated September 3, 2013 for details of the prospective and contingent resources by prospect and lead, including the geologic chance of success.

All operations in Block 10BB and Block 13T in Northern Kenya were temporarily suspended on October 28, 2013 as a precautionary measure following demonstrations by members of local communities. Operations resumed on November 8, 2013 after successful discussions relating to the operating environment with central and regional government and local community leaders. These discussions led to the signing of a memorandum of understanding which clearly lays out a plan for the Government of Kenya, county government, local communities in Northern Kenya, and the Tullow-Africa Oil joint venture to work together inclusively over the long-term and to ensure operations can continue without disruption in the future.

In November, the Company announced a new oil discovery at Agete-1 located seven kilometers north of the Twiga South-1 discovery along the Basin Bounding Fault Play in Block 13T. Logs indicate a significant oil column with an estimated 100 meters of net oil pay in good quality sandstone reservoirs.

Given the significant volumes discovered and the extensive exploration and appraisal program planned to fully assess the upside potential of the basin, the Tullow-Africa Oil joint venture agreed with the Government of Kenya to commence development studies. In addition, the partnership commenced a pre-FEED study of the export pipeline.

In December, the Company completed drilling the Bahasi-1 well in Block 9 to a depth of 2,900 meters, encountering metamorphic basement at 2850 meters. A thick section of Tertiary and Cretaceous interbedded sands and shales were encountered with only minor shows of gas throughout the section. Accordingly the well was plugged and abandoned. Subsequent to the completion of Bahasi-1, the rig moved to the Sala-1 well which completed drilling in 2014.

Also in December, the Company completed the Tutule-1 well in the South Omo Block which reached a total depth of 2101 meters. The well encountered a section similar to the nearby Sabisa-1 well in the upper portion of the well but the sands which appeared to be hydrocarbon bearing in the Sabisa well were not present on the Tultule horst block feature with multiple volcanic units and shales in this section. There were gas shows in the section which point to a potential hydrocarbon source and the results of these two wells will be analyzed to determine the future exploration program direction in the North Turkana Basin.

Also in December, the previously planned test of the Paipai-1 well in Block 10A was cancelled due to concerns over economic viability. Further, the Company and its partners elected not to continue into the next exploration phase on this block.

The Company and its partners continued to actively acquire, process and interpret an extensive 2D seismic program totaling approximately 3,044 kilometers during 2013 over Blocks 10BA, 10BB, 12A, 13T in Kenya and the South Omo Block in Ethiopia with two onshore and one offshore 2D seismic crews operating throughout the remainder of the year. A third onshore 2D seismic crew operating in the South Omo Block was released in May 2013 after completing 1,174 kilometers of 2D seismic. In addition, the Company and its partner in Blocks 10BB and 13T mobilized a 3D seismic crew to begin a 550 square kilometer 3D seismic survey over the Ngamia-1 and Twiga South-1 discoveries. The Company completed acquiring an extensive Full Tensor Gradiometry survey in December over the Rift Basin Area in Ethiopia.

FISCAL YEAR ENDED DECEMBER 31, 2014

Significant transactions in the year

In March, the Company completed a farmout transaction with Marathon whereby Marathon acquired a 50% interest in Rift Basin Area leaving AOC with 50% working interest. In accordance with the farmout agreement, Marathon was obligated to pay the Company $3.0 million in consideration of past exploration expenditures, and agreed to fund the Company's working interest share of future joint venture expenditures to a maximum of $15.0 million with an effective date of June 30, 2012. The Company maintained operatorship in Rift Basin Area, but Marathon has the right to assume operatorship if a commercial discovery is made.

Also in March, the Company completed a farmout transaction with New Age whereby New Age acquired an additional 40% interest in the Company's Adigala Block leaving AOC with 10% working interest. In accordance with the farmout agreement, New Age is obligated to fund 10% of the Company's working interest share of expenditures related to the acquisition of a planned 1,000 kilometer 2D seismic program to a maximum expenditure of $10.0 million on a gross basis, following which the Company would be responsible for its working interest share of expenditures.

In May, the Company’s common shares commenced trading on the TSX. The common shares were concurrently delisted from the TSX Venture Exchange.

In July, the Company’s common shares commenced trading on Nasdaq Stockholm. The common shares concurrently delisted from the First North exchange.

Operational activity in the year

On the back of the successful exploration activities in Kenya during 2013, the Company and its partners ramped up its exploration program in Kenya and Ethiopia. Entering the year, the Company and its partners had seven drilling rigs operating in the region. Four Tullow-Africa Oil joint venture rigs were operating in Northern Kenya in Blocks 10BB, 10BA and 13T, one of which was a testing and completions unit. In addition, the Company and its partner had a rig operating in Block 9 in Kenya, but as operations in the block had completed, this rig was released. In Ethiopia, the Company and its partners in the South Omo Block and Blocks 7/8 had rigs operating in each block. Drilling operations in both blocks were completed and the rigs released. The Company entered 2015 with three drilling rigs and one testing and completion rig operating in Kenya.

In January, the Company announced a new discovery at the Amosing-1 exploration well, located 7 kilometers southwest of the Ngamia-1 discovery and also along the Basin Bounding Fault Play in Block 10BB. Logs indicated 160 to 200 meters of potential net oil pay in good quality sandstone reservoirs.

Also in January, the Company announced a new discovery at the Ewoi-1 exploration well, the second exploration well drilled by the Tullow-Africa Oil joint venture in the Basin Flank Play on the eastern side of the South Lokichar Basin in Block 10BB. Logs indicated potential net pay of 20 to 80 meters. The main zone of interest tested approximately 50 bopd from the lower Lokhone sands, which were relatively thin and of moderate quality. Data from the well indicated that the wellbore may have been located in a downdip position and the potential to drill updip on the structure was being assessed.

In February, the Company announced the results of five well tests conducted on five Lokhone pay intervals at Etuko-1 located on the Basin Flank Play in Block 10BB. Light 36 degree API waxy crude oil was successfully flowed from three zones at a combined average rate of over 550 boepd.

In March, the Company announced the results of the Etuko-2 exploration well drilled to test the upper Auwerwer sands overlying the previously announced Etuko discovery. Etuko-2 penetrated a potential significant oil column identified from formation pressure data and oil shows while drilling and in core, with good quality reservoir, however the well flowed only water on drill stem test. The results were considered inconclusive.

Also in March, the Company announced the results of testing operations on the Ekales-1 well which confirmed this significant discovery. Two drill stem tests were completed and flowed at a combined rate of over 1,000 bopd from a combined 41 meter net pay interval. The upper zone had a very high productivity index of 4.3 stb/d/psi.

Also in March, the Company announced the results of the Emong-1 well located four kilometers northwest of Ngamia-1 field discovery in Block 13T. The well encountered oil and gas shows while drilling, however the Auwerwer sandstones that are the primary reservoirs in the Ngamia field were thin and poorly developed in Emong-1 and the well was plugged and abandoned. It is believed that the reservoir was poorly developed due to its proximity to the basin bounding fault and its location within what appears to be a local isolated slumped fault margin. The results are not expected to impact the thickness and quality of reservoir throughout the main Ngamia field area.

Also in March, the Company and its partners completed drilling the El Kuran-3 appraisal well on Block 8 in the Somali region of Ethiopia. Although the El Kuran-3 well demonstrated some oil and gas potential, the Company did not consider it warranted further evaluation due to concerns over reservoir quality and commerciality. Consequently, the Company informed the Ethiopian Government and its partners of its intention to withdraw from Blocks 7 and 8.

In May, the Company drilled a new prospect in the discovered basin in Northern Kenya, the Ekunyuk-1 well, located on the Basin Flank Play on trend with the Etuko and Ewoi discoveries. The well encountered 5 meters of net oil pay and found 150 meters of good quality Lokhone sands, although there was a lack of trap at this level within the well. The quality of Lokhone sands indicated that there was further exploration potential in this area of the basin.

Also in May, the Company released the results of the Shimela-1 well in the Chew Bahir Basin of the South Omo Block. The well reached a final depth of 1,940 meters and encountered water bearing reservoirs. Shimela-1 was drilled to test a prospect in a north-western sub-basin of the vast Chew Bahir basin. The frontier wildcat well encountered lacustrine and volcanic rocks including almost 100 meters of net sandstone reservoir within siltstones and claystones. Trace thermogenic gas shows were recorded at 1,900 meters.

Also in May, the Company announced the results of the Twiga-2 appraisal well where the initial wellbore was drilled near the basin bounding fault and encountered some 18 meters of net oil pay within alluvial fan facies, with limited reservoir quality. A decision was made to sidetrack the well away from the fault to explore north of Twiga-1 and some 62 meters of vertical net oil pay was discovered in the Auwerwer formation at Twiga-2A, similar in quality to the initial Twiga-1 discovery. Four flow tests were completed on the Twiga-2A well, achieving production rates between 150 and 3,270 bopd under natural flow with no depletion, the highest oil production rate seen in Kenya to that point in time. With optimized equipment, the maximum flow potential from the best zone could have increased to around 10,000 bopd demonstrating excellent reservoir deliverability.

In June, the Company announced that Agete-1 well test results confirmed the Auwerwer pay previously released with a tested flow rate of 500 bopd.

Also in June, the Company drilled the Agete-2 exploratory appraisal well some 2.2 kilometers southeast of Agete-1. The well intersected water bearing reservoirs at this down-dip location and further appraisal drilling is planned.

Also in June, the Company announced the results of the Ngamia-2 appraisal well, which was drilled 1.7 kilometers from the Ngamia-1 discovery well to test the northwest flank of the field. The well encountered up to 39 meters of net oil pay and 11 meters of net gas pay and appeared to have identified a new fault trap, north of the main Ngamia accumulation.

Also in June, the Company announced the Sala-1 well had resulted in a gas discovery in Block 9 onshore Kenya. The Sala-1 drilled a large 80 square kilometer anticlinal feature along the northern basin bounding fault in the Cretaceous Anza graben and encountered several sandstone intervals which had oil and gas shows. The well was drilled to a total depth of 3030 meters and petrophysical analysis indicated three zones of interest over a 1000 meter gross interval which were subsequently drill stem tested. An upper gas bearing interval tested dry gas at a maximum rate of 6 mmcf/d from a 25 meter net pay interval. The interval had net reservoir sand of over 125 meters and encountered a gas water contact so there was potential to drill up-dip on the structure where this entire interval was above the gas-water contact. A lower interval tested at low rates of dry gas from a 50 meter potential net pay interval which could also be accessed at the up-dip location. It should also be noted that there were oil shows while drilling and small amounts of oil were recovered during drilling and testing which indicated there may be potential for oil down-dip on the structure.

In July, the Company reported that the Gardim-1 exploration well, drilled on the eastern flank of the Chew Bahir Basin in the South Omo licence, onshore Ethiopia, reached a total depth of 2,468 metres in basement, without encountering commercial oil. The well intersected lacustrine and volcanic formations, similar to those found in the Shimela-1 well on the north-western flank of the basin. Minor intervals with thermogenic gas shows were intersected just above basement. The well was plugged and abandoned and drilling operations demobilised whilst drilling results are integrated into the regional basin model.

In August, the Company announced that it has informed the Ethiopian Government and its partners of its intention to withdraw from Blocks 7 and 8. Although the El Kuran-3 well did demonstrate some oil and gas potential, the Company did not feel it was warranted to continue efforts due to concerns over reservoir quality and commerciality.

Also in August, the Company announced the results of the Etom-1 exploration well located in Block 13T (Kenya), 7 kilometers north of the Agete oil discovery on the Basin Bounding Fault Play. The well encountered between 5 and 20 meters of potential net oil pay sands based on wireline logs in the Auwerwer and Upper Lokhone Formations. Oil was recovered in MDT sample chambers, which appeared to be of similar quality as the other discoveries in the basin. There was an additional 400 meters of porous sands in the Auwerwer and Lokhone Formations, which confirmed the extension of thick reservoir sections into the northern portion of the basin. Oil and gas shows were noted throughout drilling of the well confirming the extension of the petroleum system to the northern portion of the discovered basin in Northern Kenya. Based on these positive results, the original 3D seismic survey was extended to cover the northern portion of this basin where several additional large prospects had been identified by 2D seismic. The well was suspended for future drill stem testing.

Also in August, the Company drilled the Ngamia-3 and Amosing-2/2A appraisal wells in the discovered basin in Northern Kenya in Block 10BB. The results of these wells appeared to confirm the thickness and lateral extent of the Auwerwer sands at both locations and extended the known oil column significantly downdip extending the proven field areas. The range of thickness of the Auwerwer reservoir quality sands in all six penetrations of these two structures is between 146 and 200 meters, and the sands appeared to be consistent over the field areas. The planned Extended Well Test (“EWT”) programs on both of these fields will be designed to evaluate reservoir connectivity and help constrain estimates of flow rates and recovery factors for field development planning purposes.

Also in August, the Company announced that well testing had been completed on the previously announced Ewoi discovery on the eastern flank of the Lokichar Basin in Block 10BB (Kenya). The main zone of interest tested approximately 50 barrels of oil per day from the lower Lokhone sands which were relatively thin and of moderate reservoir quality. Data from the well suggested that the wellbore may have been located in a downdip position and the Company considered updip appraisal opportunities on this structure.

In September, the Company announced details of an updated independent assessment of the Company’s Contingent Resources in the South Lokichar Basin located in Blocks 10BB and 13T in Kenya. The effective date of the assessment was July 31, 2014. Please refer to the Company’s press release dated September 16, 2014 for the details of the Contingent Resources.

In October, the Company announced the results of the Kodos-1 basin opening exploration well drilled in the Kerio Basin in Block 10BB (Kenya). The well encountered hydrocarbon shows, which indicated the presence of an active petroleum system. This was the first well in the Kerio basin, northeast of the discovered basin in Kenya, and it appears to have been drilled in an area of unfavorable reservoir development, near the basin bounding fault.

Also in October, the Company announced the results of the Ekosowan-1 exploration well located in Block 10BB, 12 kilometers southeast and updip of the Amosing oil discovery. The well encountered a 900 meter column of near continuous oil shows throughout an interval of tight sands which also appeared to be as a result of drilling too close to the basin bounding fault. A downdip appraisal well between the Amosing field and this potential updip sealing location was considered.

Also in October, the Company drilled the Ngamia-4 appraisal well located 1.1 kilometers west of the Ngamia-1 discovery. The well encountered up to 120 meters of hydrocarbon pay, of which up to 80 meters was oil. This well was suspended for use in future appraisal and development activities.

Also in October, the Company announced the results of four flow tests on the Twiga-2A well in Block 13T, achieving production rates between 150 and 3,270 bopd under natural flow with no depletion, the highest oil production rate seen to date in Kenya. With optimised equipment the maximum flow potential from the best zone could have increased to around 10,000 bopd demonstrating excellent reservoir deliverability. Due to these positive test results, further appraisal wells are being considered at Twiga.

Also in October, the Company announced the Sala-2 appraisal well failed to find significant hydrocarbons updip from the Sala-1 gas discovery. There appears to be a stratigraphic or structural separation between the two wells. The Company reviewed additional potential appraisal targets as well as on trend prospects in the block which has proven oil and gas generation.

Africa Energy informed the Government of Puntland (Somalia) that it would be downsizing its office in Bosaso, Puntland and would refrain from any operational activity in the Dharoor and Nugaal Valley Block and associated expenditures until the political situation improved in Somalia. Africa Energy also requested a two year extension to the current exploration period from the Puntland Government to allow time for the ongoing political challenges to be resolved.

The Company notified its Joint Venture Partners of its decision to withdraw from its 10 per cent working interest in the Adigala Block (Ethiopia). Accordingly, the Company elected during the fourth quarter of 2014 to record a non-cash impairment charge related to costs associated with this Block.

FISCAL YEAR ENDED DECEMBER 31, 2015

Significant transactions in the year

During February 2015, the Company completed a brokered private placement issuing an aggregate of 57,020,270 shares at a price of SEK 18.50 (CAD 2.74 equivalent) per common share for gross proceeds of SEK 1,055 million or $125 million. A cash commission (4% of the gross proceeds) was paid in the amount of $4.5 million to Dundee Securities Europe LLP and Pareto Securities who acted as joint bookrunners to advise on and effect the private placement.

During May 2015, the Company completed a non-brokered private placement with Stampede Natural Resources S.a.r.l., an entity owned by a fund advised by Helios Investment Partners LLP, issuing an aggregate of 52,623,377 shares at a price of CAD $2.31 for gross proceeds of $100 million.

During August 2015, the Company completed a $50 million non-brokered private placement Pursuant to an Equity Subscription Agreement dated August 18, 2015, 31,169,048 common shares, issued at a price of CAD $2.10 per share for gross proceeds of CAD $65,455,000 (US $50 million[2]) were issued to IFC, a member of the World Bank Group.

[2] Based on the USD CAD Noon Rate (1.3091) posted by the Bank of Canada for August 17, 2015.

In November, 2015, the Company announced that it had entered into a definitive farmout agreement with Maersk whereby Maersk will acquire 50% of Africa Oil's interests in Blocks 10BB, 13T and 10BA in Kenya and the Rift Basin and South Omo Blocks in Ethiopia in consideration for reimbursement of a portion of Africa Oil's past costs and a future carry on certain exploration and development costs.

Under the terms of the farmout agreement, upon closing of the transaction Maersk will pay Africa Oil US$350 million as reimbursement of past costs incurred by Africa Oil prior to the agreed March 31, 2015 effective date. Maersk will also reimburse Africa Oil for its acquired working interest share of costs incurred between the effective date and the closing date. Commencing on the effective date, Maersk will also carry up to US$75 million of the Company's share of development expenditures upon confirmation of resources and US$15 million of the Company's share of exploration expenditures. In addition, upon Final Investment Decision, Maersk will also carry up to US$405 million of Africa Oil's working interest share of development expenditures for the Lokichar Development Project. The total carry amount is contingent upon the Lokichar Development Project meeting certain thresholds of resource growth, and the timing of first oil. The transaction was subject to host government and applicable regulatory approvals. The Maersk farmout closed subsequent to year end (refer to Overview of Farmount and Joint Venture Agreements section below).

During 2015, the composition of Africa Energy's board of directors changed and Africa Oil's ownership interest (currently 32%) was diluted due to equity financings completed by Africa Energy. Africa Energy Corp. is no longer considered a subsidiary of the Company and is accounted for as an equity investment. In June 2015, Africa Energy and its joint venture partners notified the Government of Puntland (Somalia) of their decision to withdraw from the Nugaal Block and Dharoor Block PSAs.

Operational activity in the year

The 2015 work program has been primarily focused on appraisal of the discovered South Lokichar Basin with the following objectives; confirming reservoir quality and deliverability, resource size and definition, and advancement of the development plans, including the export pipeline. The Company entered the year with three drilling rigs active in Kenya. Two rigs were demobilized during the year. One drilling rig was active at the end of 2015 and is expected to be released in the first quarter of 2016. A limited number of potential basin opening wells were drilled in Kenya during 2015 outside of the discovered South Lokichar Basin. In Ethiopia, efforts during the year were focused on a 2D seismic program in the Rift Basin Area Block.

Tertiary Rift - Kenya

In January 2015, the Company announced the completion of drilling the Ngamia-5 and Ngamia-6 appraisal wells. Ngamia-5 is located 500 metres northeast of the Ngamia-1 discovery well in a different fault compartment and encountered 160 to 200 metres net oil pay. Ngamia-6 is located approximately 800 metres north of Ngamia-1 and in the same fault compartment as Ngamia-5 and encountered up to 135 metres net oil pay.

During the first quarter of 2015, the Epir-1 exploration well was drilled to a total depth of 3,057 meters in the North Kerio Basin in Block 10BB, Kenya. The well encountered a 100 meter interval of wet hydrocarbon gas shows with florescence indicating the presence of an active petroleum system. The hydrocarbon shows were encountered primarily in rocks which were not of reservoir quality. The partnership was encouraged that the Epir-1 well had demonstrated a working hydrocarbon system in the Kerio Basin and technical work will now focus on identifying a prospect in the basin where there is a high chance of trapping hydrocarbons in reservoir quality rock.

The Engomo-1 well was drilled in the first quarter of 2015, which was the first test of the North Turkana Basin in Block 10BA, Kenya. This prospect is to the west of Lake Turkana where numerous naturally occurring oil slicks and seeps have been observed. The Engomo-1 exploration well in Block 10BA was drilled to a total depth of 2,353 meters. The well encountered interbedded siltstones, sandstones and claystones, becoming more tuffaceous and tight until reaching a total depth in basement. No significant oil or gas shows were encountered and the well was plugged and abandoned. The prevalence of tight facies in the wellbore may be due to the well's close proximity to the basin bounding fault. Future analysis will be focused on understanding how this result impacts the remaining prospectivity in the basin.

During the first quarter of 2015, in the Ngamia field, the Ngamia-7 and Ngamia-8 appraisal wells were drilled. The Ngamia-7 well was drilled 1.2 kilometers east of Ngamia-3 and encountered up to 130 meters of net oil pay identifying a large eastern extension of the field that had been identified from the new 3D seismic survey. The Ngamia-8 appraisal was drilled and encountered up to 200 meters of net oil pay in line with pre-drill expectations. The well was positioned in the center of the Ngamia structure and static pressure data indicated the well is in pressure communication with the oil discovered in the neighbouring Ngamia-1A, Ngamia-3, Ngamia-5, Ngamia-6 and Ngamia-7 wells. During the second quarter of 2015, the drilling of the Ngamia-9 well was completed and encountered between 90 and 110m of pay in the Lokone and Auwerwer horizons.

During the first quarter of 2015 in the Amosing field, the Amosing-3 appraisal well, located one kilometer northwest of the Amosing-1 discovery, was drilled. The well encountered up to 140 meters of net oil pay and proved an extension of the field. Pressure data from the Amosing-3 well indicated connectivity in some reservoir horizons encountered in the Amosing-1, 2 & 2A wells. The Amosing-4 well, located approximately one kilometer southeast of the Amosing-1 well, was drilled to test the southern extent of the field and successfully encountered 27 meters of net oil pay in thick upper reservoir zones proving the significant down-dip extent of the field. Mapping of the Amosing field does not close the structure to the south and there is potential for the field to spill up-dip into the Ekosowan prospect area, where the Ekosowan-1 well was drilled last year encountering a 900 meter column of near continuous oil shows in tight alluvial fan facies. The Amosing-4 well has further de-risked drilling of the Ekosowan prospect.

Elsewhere in the Lokichar basin, during the first quarter of 2015, the Ekales-2 appraisal well reached a total depth of 4,059 meters and encountered an estimated 60-100 meters of net oil pay in the primary shallower objectives. This highly deviated well was also deepened to test the basin center stratigraphic play where it intersected sandstones with elevated pressures and 50 meters of oil bearing sands; however, operating conditions precluded logging and confirmation of any oil pay in this section. This was the first test of this exploration target and is very positive for the future upside potential of the South Lokichar Basin, above the significant oil resources already discovered.

In the Twiga field the Twiga-3 exploratory appraisal well in Block 13T encountered sands within the Lokone Shale sequence that are interpreted as good quality oil bearing reservoir over a gross interval of 120 metres. This result will be assessed in future exploration and appraisal activities, stepping out into the South Lokichar basin to further define this encouraging additional oil potential.

During the first half of 2015, in preparation for the EWTs, the Amosing-1 and Amosing-2A wells were successfully completed in five separate zones. Initial rig-less flow testing during clean-up flowed at a cumulative maximum rate of 5,600 and 6,000 bopd respectively. These results exceeded expectations, and demonstrated high quality reservoir sands which flowed 31 to 38 degree API dry oil under natural conditions. During the test the wells produced at a cumulative average constrained rate of 4,300 bopd under natural flow conditions. Pressure data from the two wells supports significant connected oil volumes and confirms lateral reservoir continuity, which is positive for the future development. A cumulative volume of 30,000 barrels of oil has been produced into storage. Water injection tests are being planned to further validate the viability of water flood reservoir management and the oil recovery assumptions.

The partnership has completed the Ngamia Extended Well Test production phase with approximately 38,000 barrels of oil produced. Five completed zones of the Ngamia-8 production well were tested individually at a cumulative rate of 2,400 bopd and all except the lowest zone produced without artificial lift. Communication between the producer well and an observation well, at a distance of approximately 500 metres, was also demonstrated. Water injection tests were being planned to further validate the viability of water flood reservoir management and the oil recovery assumptions.

In the third quarter of 2015, the Amosing-5A exploratory appraisal well was drilled as a test of an undrilled fault block. The well encountered an estimated 15 to 28 metres of net oil pay in a downflank position and successfully proved a northern extension to the Amosing field.

During the fourth quarter of 2015, the Emesek-1 exploration well was drilled, testing the undrilled North Lokichar basin in Block 13T. The well reached a total depth of 3,000 metres without encountering commercial hydrocarbons and was plugged and abandoned. The rig subsequently moved to the South Lokichar basin to drill the Etom-2 well in an undrilled fault block adjacent to the Etom oil discovery in Block 13T. The well encountered 102 metres of net oil pay in two columns. The objective of the well was to explore the north flank of the Etom structure in an untested fault block identified by recent 3D seismic. Oil samples, sidewall cores and wire line logging all indicated the presence of high API oil in the best quality reservoir encountered in the South Lokichar Basin to date.

Discovering this thick interval of high quality oil reservoirs at Etom-2 further underpins the development options and resource base in the South Lokichar Basin. The result follows careful evaluation of 3D seismic data which was shot after the Etom-1 well completed drilling and demonstrates how the partnership has improved its understanding of the basin. This result also suggests significant potential in this underexplored part of the block as it is the most northerly well drilled in South Lokichar and is located close to the axis of the basin away from the basin-bounding fault. Accordingly, Tullow and Africa Oil will review the resource potential of the greater Etom area and neighbouring prospects as part of a future exploration drilling program.

Following Etom-2, the PR Marriott Rig-46 moved to Block 12A where it is currently drilling the Cheptuket-1 exploration well, the first well to be drilled in the Kerio Valley Basin. Following the drilling of Cheptuket the drilling rig will be released while a future program is considered.

The full fast track processed data set for the 951 square kilometer 3D seismic survey over the series of significant discoveries along the western basin bounding fault in the South Lokichar Basin, is now available and is being interpreted. The 3D seismic indicates significantly improved structural and stratigraphic definition and additional prospectivity not evident on the 2D seismic.

In addition, the partnership acquired over 1,100 meters of whole core from the wells drilled in the South Lokichar Basin, and an extensive program of detailed core analysis is ongoing. A key focus of the core program is to better assess oil saturation and to refine the recovery factors of the main reservoir sands. Core analysis results support the reservoir assumptions used in the contingent resource estimate and are reducing the uncertainty around oil saturations in the reservoir.

The extensive appraisal activities in Kenya, including the EWTs, along with the development concept studies completed in 2014, are addressing key reservoir uncertainties around the South Lokichar contingent resource estimate. The results to date from the ongoing appraisal drilling program and Amosing EWT results provides significant comfort that the reservoir sands are connected over an area larger than the assumed development well spacing which will narrow the range of uncertainty around recovery factors.

The draft field development plan for the discoveries in the South Lokichar Basin was submitted in December 2015. Preparation for FEED is under way, and is expected to commence in 2016.

In August 2015, a bilateral agreement was reached between the Presidents of Uganda and Kenya adopting the Northern Kenya route for the regional crude oil pipeline, subject to certain conditions. Africa Oil continues to support both countries in moving this project forward as quickly and efficiently as possible taking into account the needs of all stakeholders.

Cretaceous Anza Rift – Kenya

In Block 9, the Company continues to assess the results of its 2014 drilling program. The Government of Kenya has granted an eighteen month extension to the second additional exploration period, which will now expire in June 2017.

Tertiary Rift – Ethiopia

During the third quarter of 2015 in the Rift Basin Area Block, a 2D seismic program was completed, which consisted of approximately 600 kilometers of land and lake seismic. Source rock outcrops and oil slicks on the lakes have been identified in the block where there was previously no existing seismic or wells. The Government of Ethiopia granted a twelve month extension to the initial exploration period, which will now expire in February 2017.

ITEM 4 NARRATIVE DESCRIPTION OF THE BUSINESS

Summary

AOC's long range plan is to increase shareholder value through the acquisition, exploration and development of oil and gas assets, located in under-explored geographic areas, in the early phase of the upstream oil and gas life-cycle. The Company has actively explored on multiple onshore exploration blocks in various geological settings in East Africa. The Company has made numerous oil discoveries in the South Lokichar Basin (Blocks 10BB and 13T) located in the Tertiary Rift trend in Kenya. Appraisal activities, including extended well testing, appraisal drilling and engineering studies are being undertaken with the goal of sanctioning development of the oil fields in the South Lokichar Basin. Africa Oil will continue to consider acquisition and merger opportunities with a focus on North Africa and the Middle East

The board of directors of Africa Oil may, in its discretion, approve asset or corporate acquisitions or investments that do not conform to the guidelines discussed above based upon the board's consideration of the qualitative and quantitative aspects of the subject properties, including risk profile, technical upside, resource potential, reserve life and asset quality.

Specialized Skill and Knowledge

The Company relies on specialized skills and knowledge to gather, interpret and process geological and geophysical data, design, drill and complete wells, and numerous additional activities required to explore for, and potentially produce, oil and natural gas. The Company has employed a strategy of contracting consultants and other service providers to supplement the skills and knowledge of its permanent staff in order to provide the specialized skills and knowledge to undertake its oil and natural gas operations efficiently and effectively.

Competitive Conditions

The petroleum industry is immensely competitive in all of its phases. Africa Oil competes with other participants in the search for, and the acquisition of, oil and natural gas interests located in North Africa and the Middle East. Africa Oil's competitors include other resource companies which may have greater financial resources, staff and facilities than those of the Company. Competitive factors which may come into play in the future include the distribution and marketing of oil and natural gas, pricing, and methods of improving reliability of delivery.

Economic Dependence

The Company is heavily dependent upon the results obtained under agreements, including production sharing agreements, joint venture agreements and farmout agreements that it has entered into for the exploration, appraisal, development and production of hydrocarbons.

OVERVIEW OF FARMOUT AND JOINT VENTURE AGREEMENTS

The following narrative provides an overview of the Company's farmout and joint venture agreements related to its current operations:

Farmout Agreements with Tullow

On September 1, 2010, AOC and Tullow entered into the Tullow Farmout Agreement. Under the Tullow Farmout Agreement, AOC agreed to assign to Tullow a 50% interest in and operatorship of, each of the Block 10A PSC, the Block 10BB PSC and the South Omo Block PSA. Tullow was also granted an option to acquire a 50% interest in the Blocks 12A and 13T PSCs, which it subsequently exercised (see below).

In consideration of the assignment, Tullow has paid AOC $9.5 million, representing 50% of AOC's audited past costs in the blocks. In addition, Tullow agreed to fund its 50% working interest and AOC's working interest share of joint venture expenditures on Blocks 10A, 10BB, and South Omo from July 1, 2010, the effective date, until the cap of $23.75 million (based on AOC's carried interest) was reached. Upon reaching the expenditure cap, AOC was responsible for its working interest share of future joint venture expenditures.

The South Omo portion of the farmout to Tullow was completed on December 9, 2010. The farmout of Blocks 10A and 10BB to Tullow was completed in January 2011.

Tullow exercised its option in respect of the Blocks 12A and 13T PSCs on September 1, 2010 and entered into the 12A/13T Farmout Agreement with AOC in respect of those blocks, on January 26, 2011. Under the 12A/13T Farmout Agreement, AOC agreed to assign to Tullow 50% interest in, and operatorship of, each of Blocks 12A and 13T in consideration of $1.55 million, being 50% of AOC's past costs in respect of the blocks plus 50% of gross petroleum costs incurred by AOC from September 9, 2010, to a maximum of $500,000. On February 22, 2011, the Company closed on the 12A/13T farmouts at which time Tullow paid the Company an aggregate of $1,686,432. Tullow and AOC are each responsible for their working interest share of joint venture expenditures in these blocks going forward.

As a result of the completion of the Centric Plan of Arrangement, the Company acquired an interest in Block 10BA, Kenya in February 2011. Block 10BA is the subject of the 10BA Farmout Agreement. Pursuant to the terms of the 10BA Farmout Agreement, Tullow acquired a 50% interest in, and operatorship of, Block 10BA in consideration of the reimbursement of 50% of Centric's acquisition costs, being approximately $750,000, and the payment of 80% of the first $30 million of expenditures required under the Block 10BA PSC. Upon reaching the expenditure cap, each joint venture partner was responsible for its working interest share of future costs. On November 4, 2010, Kenyan Government approval to the 10BA Farmout Agreement was received and on January 26, 2011, the transaction closed at which time Tullow paid to Centric an amount of $1.0 million in respect of estimated historic costs related to the acquisition of the PSC and exploration of Block 10BA.

In July 2012, the Company completed a farmout transaction with Tullow whereby Tullow paid the Company $1.1 million in consideration of past exploration expenditures to acquire an additional 15% interest in Block 12A in Kenya. Tullow agreed to fund 15% of the Company's working interest share of expenditures related to the acquisition of 520 Kilometers of 2D seismic until an expenditure cap of $10.3 million on a gross basis, following which the Company would be responsible for its working interest share of seismic acquisition costs.

Rift Basin Area, Ethiopia

In December 2010, the Company signed a definitive agreement (the "Joint Study Agreement") with the Ethiopian Government to jointly study the Rift Basin Area (formerly referred to as the "Rift Valley Block"). The Company committed to carry out an airborne geophysical survey over the Block. The Joint Study Agreement had an 18 month term, following which the Company could enter into negotiations for a production sharing agreement for all or part of the Rift Basin Area.

In February 2013, the Company entered into a PSA on the Rift Basin Area in Ethiopia with the Ministry of Mines, Government of Ethiopia. Under the Rift Basin Area PSA, during the initial exploration period which expires in February 2017, the Company is obligated to complete geological and geophysical operations (including the acquisition of 8,000 square kilometers of full tensor gravity and 400 kilometers of 2D seismic) with a minimum gross expenditure of $5.0 million.

Farmout Agreement with Marathon Oil Corporation

In October 2012, the Company completed a farmout transaction with Marathon whereby Marathon acquired a 50% interest in Block 9 and a 15% interest in Block 12A, both in Kenya. In accordance with the farmout agreement, Marathon paid the company $32.0 million in consideration of past exploration expenditures, and has agreed to fund the Company's working interest share of future joint venture expenditures on these blocks to a maximum of $25 million. The Company will maintain operatorship in Block 9, but Marathon has the right to assume operatorship if a commercial discovery is made.

In March 2014, the Company completed another farmout transaction with Marathon whereby Marathon acquired a 50% interest in the Rift Basin Area of Ethiopia. Africa Oil maintains operatorship of the block, but Marathon has the right to assume operatorship if a commercial discovery is made. In consideration for the assignment of this interest, Marathon will pay the Company an entry payment of $3.0 million in respect of past costs, and has agreed to fund $15.0 million of Africa Oil's working interest share of joint venture expenditures in the Rift Basin Area. Africa Oil and Marathon each hold a 50% working interest in the Rift Basin Area.

Farmout Agreement with New Age (Africa Global Energy) Limited

In October 2012, the Company completed a farmout transaction with New Age whereby New Age acquired an additional 25% interest in the Company's Blocks 7 & 8 in Ethiopia, together with operatorship of Blocks 7 & 8 and the Adigala Area. In accordance with the farmout agreement, New Age paid the Company $1.5 million in consideration of past exploration expenditures. New Age already held a 15% interest in Blocks 7 & 8, bringing its total interest to 40%.

During the third quarter of 2014, the Company notified the Ethiopian Government and its partners that it intended to withdraw from Blocks 7 and 8.

In March 2014, the Company completed another farmout transaction with New Age whereby New Age acquired an additional 40% working interest in the Adigala Block, in Ethiopia. The Company’s interest has now been reduced to 10%. In consideration of the assignment New Age will carry Africa Oil’s working interest share of a planned 1,000 kilometer 2D seismic work program in the Adigala Block.

During the first quarter of 2015, the Company notified the Ethiopian Government and its partners of its decision to withdraw from Adigala.

Farmout Agreement wth Maersk

On November 9, 2015, the Company announced that it had entered into a definitive farmout agreement with Maersk Olie og Gas A/S ("Maersk") whereby Maersk would acquire 50% of the Company's interests in Blocks 10BB, 13T and 10BA in Kenya and the Rift Basin and South Omo Blocks in Ethiopia in consideration for reimbursement of a portion of the Company's past costs incurred and a future carry on certain exploration and development costs. A $52.5 million deposit was paid at that time.

On February 4, 2016, the Company announced the completion of the farmout with Maersk related to Kenyan Blocks 10BB, 13T and 10BA. At completion, Africa Oil received $427 million (inclusive of the deposit previously paid) from Maersk. This amount represents $344 million of reimbursed past costs incurred by Africa Oil prior to the agreed March 31, 2015 effective date of the farmout and $83 million representing Maersk's share of costs incurred between the effective date and December 31, 2015, including a carry reimbursement of $15MM of exploration expenditures. An additional $75 million development carry may be available to Africa Oil upon confirmation of existing resources, which is expected to take place in the first quarter of 2016. Upon Final Investment Decision ("FID"), Maersk will be obligated to carry Africa Oil for an additional amount of up to $405 million depending on meeting certain thresholds of resource growth and timing of first oil.

On February 22, 2016, the Company announced the completion of the farmout with Maersk related to the South Omo and Rift Basin Blocks Ethiopia. At completion, Africa Oil received $12.8 million from Maersk. This amount represents $6.4 million of reimbursed past cost incurred by Africa Oil prior to the agreed March 31, 2015 effective date of the farmout and $6.4 million representing Maersk’s share of costs incurred between the effective date and December 31, 2015.

PRODUCTION SHARING CONTRACTS OVERVIEW

Block 10BB, Kenya (25% working interest – following completion of Maersk farmout)

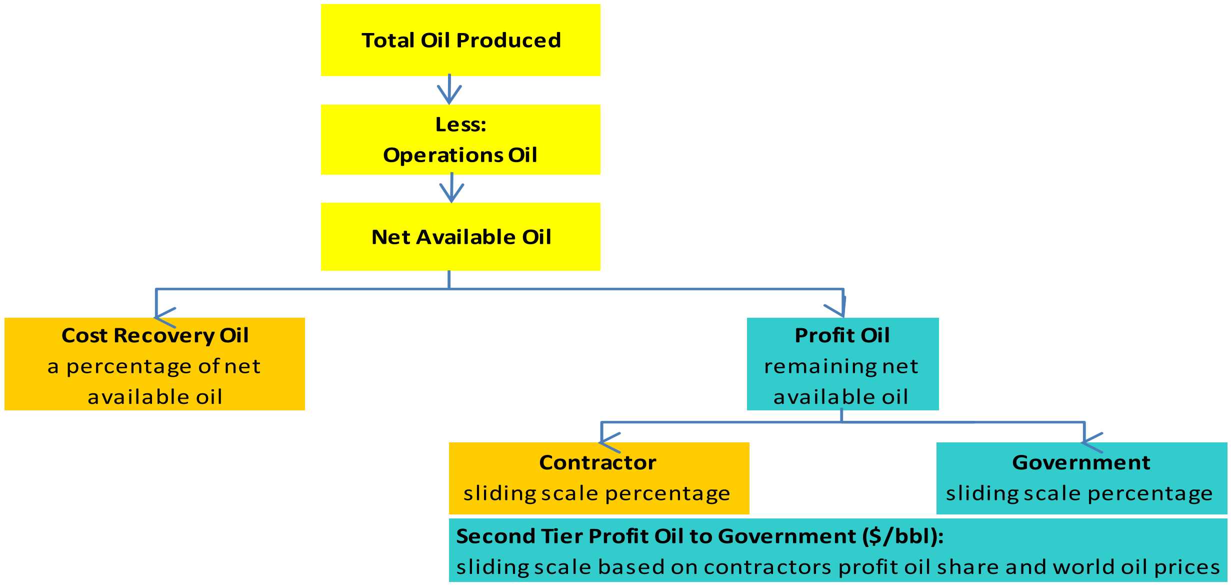
The Block 10BB PSC contemplates an initial four year exploration period and, at the option of the Contractor Group, two additional exploration periods of two years each. The Contractor Group is currently in the second additional exploration period which expires in July 2017.

During the second additional exploration period, the Contractor Group is required to acquire and interpret 250 km^2 of 3D seismic at a minimum cost of $7.0 million. In addition, the Contractor Group is required to drill three exploratory wells, to a vertical depth of at least 3,000 meters per well. The minimum required expenditure for each well is $6.0 million.

The Kenyan Government may elect to participate in any petroleum operations in any development area and acquire an interest of up to 20% of the total interest in that development area. The Kenyan Government may exercise its participation rights within six months from the date a development plan is adopted. Upon electing to participate in a development area, the Government would assume responsibility for its share of costs incurred with respect to the development area.

A 25 year development and production period commences once the Contractor Group has made a commercial discovery and a development plan is adopted.

The following diagram illustrates the allocation of production under the terms of the Block 10BB PSC:



Of the "Total Oil Produced", "Operations Oil" is available to the Contractor Group for operational needs for the work performed under the PSC. Up to a stated maximum percentage of the "Net Available Oil" is available for cost recovery with the remainder allocated to "Profit Oil". Costs subject to cost recovery include all costs and expenditures incurred by the Contractor Group for exploration, development, production and decommissioning operations, as well as any other applicable costs and expenditures incurred directly or indirectly with these activities. The portion of Profit Oil available to the Contractor Group is based on a sliding scale with the portion allocated to the Contractor Group declining as the volume of Profit Oil increases.

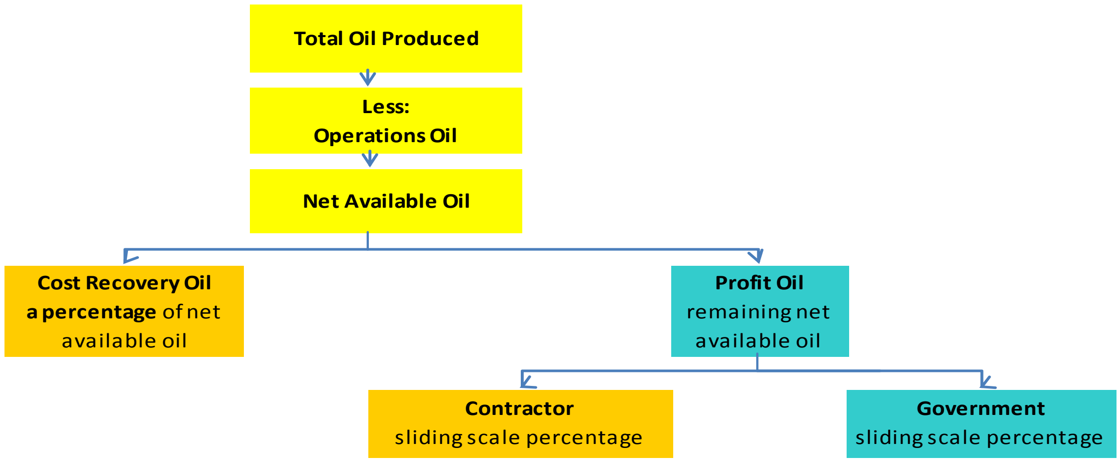
A second tier Profit Oil payment is due to the Government when oil prices exceed a stated world oil price. The amount payable per barrel is calculated by multiplying the Contractor Group's share of Profit Oil by a stated percentage and by the prevailing oil price in excess of the contractually agreed threshold world oil price.

Block 9, Kenya (50% working interest)
The Company completed drilling the Bogal-1 well in May 2010 and entered the first additional exploration phase under the Block 9 PSC. Although the Company was required to relinquish 25% of the original contract area at the end of the first exploration period, the Kenyan Ministry waived the requirement to relinquish.

The Company completed drilling the Bahasi-1 well in December 2013 and entered the second additional exploration period under the Block 9 PSC in December 2015. During the second additional exploration period, which has a two year term, the Company is required to, in consultation with the Ministry of Energy for the Republic of Kenya, determine how much 2D or 3D seismic work, if any, is required. In addition, the Company is required to drill one well, to a vertical depth of at least 1,500 meters. The minimum required expenditure for the well is $3.0 million. During May 2015, the Company received approval for an eighteen month extension to the second additional exploration period which will expire on June 30, 2017.

The Kenyan Government may elect to participate in any petroleum operations in any development area and acquire an interest of up to 13% of the total interest in that development area. The Kenyan Government may exercise its participation rights within six months from the date a development plan is adopted. Upon electing to participate in a development area, the Government would assume responsibility for its share of costs incurred with respect to the development area.

A development and production period commences once the Company has made a commercial discovery and a development plan is adopted. The development and production period is 25 years with a possible 10 year extension.
The following diagram illustrates the allocation of production under the terms of the Block 9 PSC:



Of the "Total Oil Produced", "Operations Oil" is available to the Company for operational needs for the work performed under the PSC. Up to a stated maximum percentage of the "Net Available Oil" is available for cost recovery with the remainder allocated to "Profit Oil". Costs subject to cost recovery include all costs and expenditures incurred by the Company for exploration, development, production and decommissioning operations, as well as any other applicable costs and expenditures incurred directly or indirectly with these activities. The portion of Profit Oil available to the Company is based on a sliding scale with the portion allocated to the Company declining as the volume of Profit Oil increases.

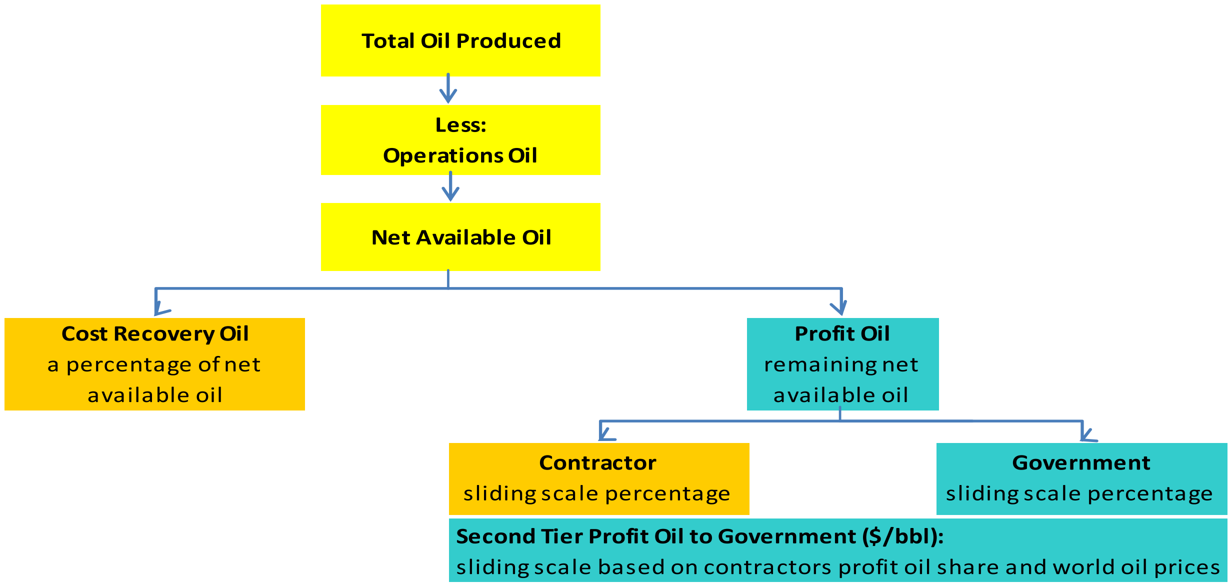
Block 13T, Kenya (25% working interest – following completion of Maersk farmout)
The Block 13T PSC contemplates an initial three year exploration period and, at the option of the Contractor Group, two additional exploration periods of two years each. The Contractor Group is currently in the second additional exploration period which expires in September 2017.

During the second additional exploration period, the Contractor Group is required to acquire and interpret an additional 200 km^2 of 3D seismic at a minimum cost of $6.0 million. In addition, the Contractor Group is required to drill one exploratory well to a vertical depth of at least 3,000 meters. The minimum required expenditure for each well is $15.0 million.

The Kenyan Government may elect to participate in any petroleum operations in any development area in the Block and acquire an interest of up to 22.5% of the total interest in that development area, 15% of which will be held by the Kenyan Government and 7.5% which will be held by the National Oil Corporation of Kenya. The Kenyan Government and the National Oil Corporation of Kenya may exercise its participation rights within six months from the date a development plan is adopted. Upon electing to participate in a development area, the Government and the National Oil Corporation of Kenya would assume responsibility for its share of costs incurred with respect to the development area.

A 25 year development and production period commences once the Contractor Group has made a commercial discovery and a development plan is adopted.

The following diagram illustrates the allocation of production under the terms of the Block 13T PSC:



Of the "Total Oil Produced", "Operations Oil" is available to the Contractor Group for operational needs for the work performed under the PSC. Up to a stated maximum percentage of the "Net Available Oil" is available for cost recovery with the remainder allocated to "Profit Oil". Costs subject to cost recovery include all costs and expenditures incurred by the Contractor Group for exploration, development, production and decommissioning operations, as well as any other applicable costs and expenditures incurred directly or indirectly with these activities. The portion of Profit Oil available to the Contractor Group is based on a sliding scale with the portion allocated to the Contractor Group declining as the volume of Profit Oil increases.

Block 12A, Kenya (20% working interest)

The Block 12A PSC contemplates an initial three year exploration period and, at the option of the Contractor Group, two additional exploration periods of two years each. The first exploration period expiry was extended to September 2014. The Contractor Group is currently in the first additional exploration period which expires in September 2016.

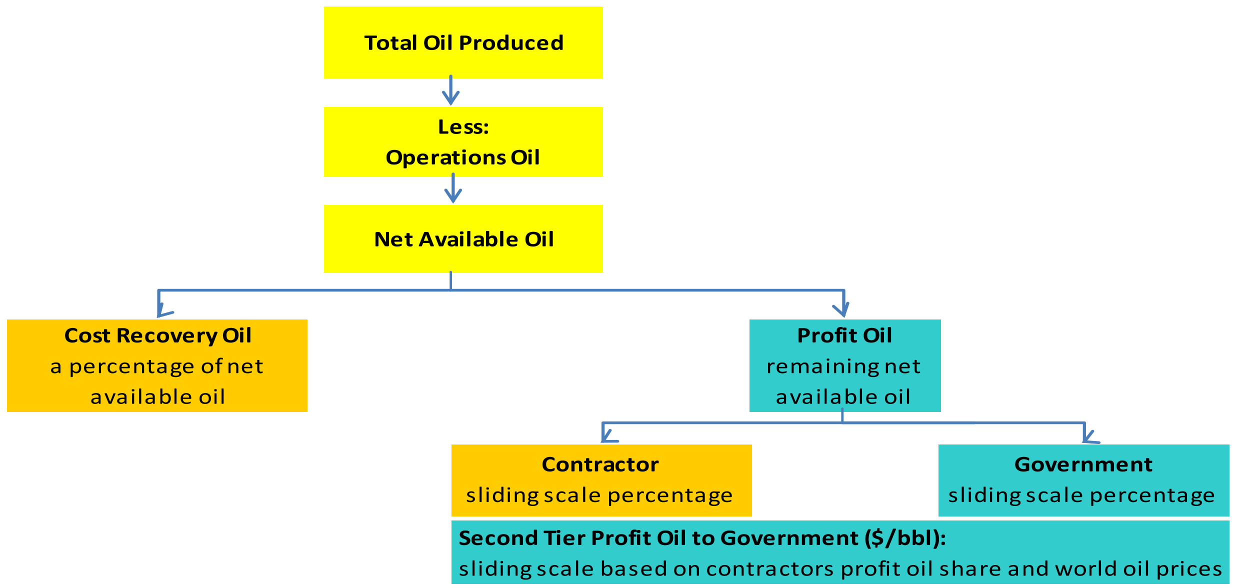
During the first additional exploration period, the Contractor Group is required to acquire and interpret an additional 200 km^2 of 3D seismic at a minimum cost of $6.0 million. In addition, the Contractor Group is required to drill one well exploratory well to a vertical depth of at least 3,000 meters. The minimum required expenditure for the well is $15.0 million. At the end of the first additional exploration period, the Contractor Group must relinquish an additional 25% of the remaining contract area.

During the second additional exploration period, the Contractor Group is required to acquire and interpret an additional 200 km^2 of 3D seismic at a minimum cost of $6.0 million. In addition, the Contractor Group is required to drill one exploratory well to a vertical depth of at least 3,000 meters. The minimum required expenditure for the well is $15.0 million.

The Kenyan Government may elect to participate in any petroleum operations in any development area in the Block and acquire an interest of up to 22.5% of the total interest in that development area, 15% of which will be held by the Kenyan Government and 7.5% which will be held by the National Oil Corporation of Kenya. The Kenyan Government and the National Oil Corporation of Kenya may exercise its participation rights within six months from the date a development plan is adopted. Upon electing to participate in a development area, the Government and the National Oil Corporation of Kenya would assume responsibility for its share of costs incurred with respect to the development area.

A 25 year development and production period commences once the Contractor Group has made a commercial discovery and a development plan is adopted.

The following diagram illustrates the allocation of production under the term the PSC:



Of the "Total Oil Produced", "Operations Oil" is available to the Contractor Group for operational needs for the work performed under the PSC. Up to a stated maximum percentage of the "Net Available Oil" is available for cost recovery with the remainder allocated to "Profit Oil". Costs subject to cost recovery include all costs and expenditures incurred by the Contractor Group for exploration, development, production and decommissioning operations, as well as any other applicable costs and expenditures incurred directly or indirectly with these activities. The portion of Profit Oil available to the Contractor Group is based on a sliding scale with the portion allocated to the Contractor Group declining as the volume of Profit Oil increases.

A second tier Profit Oil payment is due to the Government when oil prices exceed a stated world oil price. The amount payable per barrel is calculated by multiplying the Contractor Group's share of Profit Oil by a stated percentage and by the prevailing oil price in excess of the contractually agreed threshold world oil price.

Block 10BA, Kenya (25% working interest – following completion of Maersk farmout)

The Block 10BA PSC contemplates an initial three year exploration period and, at the option of the Contractor Group, two additional exploration periods of two years each. The first exploration period was extended to April 2014. The Contractor Group is currently in the first additional exploration period which will expire in April 2016.

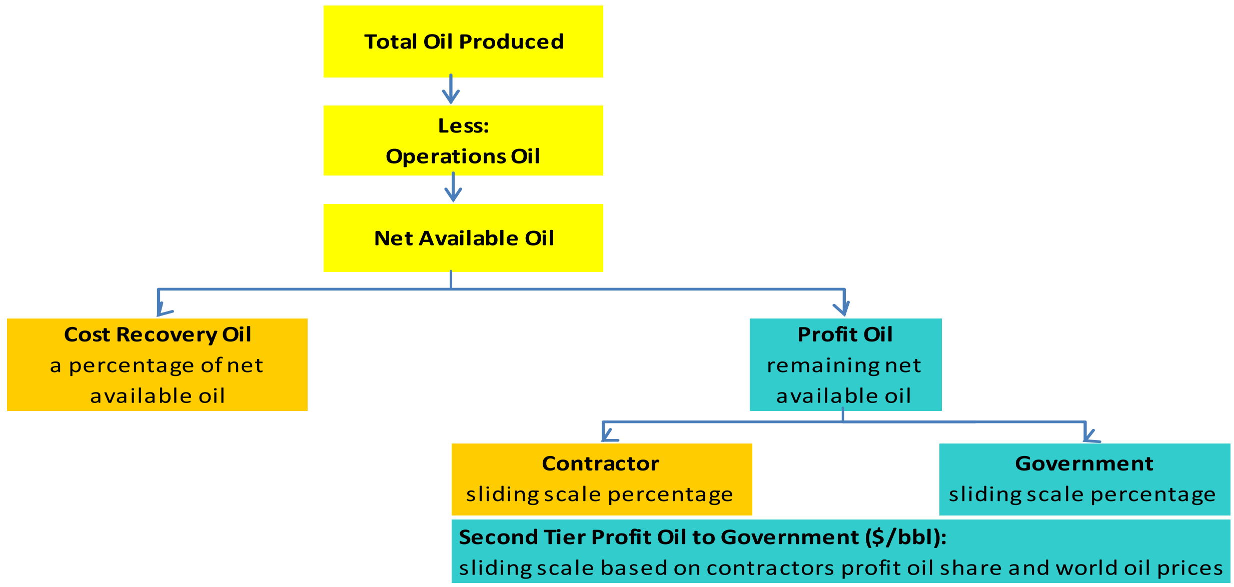
During the first additional exploration period, the Contractor Group is required to acquire and interpret 1,000 kilometers of 2D seismic or carry out surveys of 50 km^2 of 3D seismic and drill one well or carry out surveys of 45 km^2 of 3D seismic at a minimum cost of $17.0 million. At the end of the first additional exploration period, the Contractor Group must relinquish an additional 25% of the remaining contract area.

During the second additional exploration period, the Contractor Group is required to carry out surveys of 500 kilometers of 2D seismic or carry out surveys of 25 km^2 of 3D seismic and drill two exploratory wells at a minimum cost of $19.0 million.

The Kenyan Government may elect to participate in any petroleum operations in any development area and acquire an interest of up to 10% of the total interest in that development area. The Kenyan Government may exercise its participation rights within six months from the date a development plan is adopted. Upon electing to participate in a development area, the Government would assume responsibility for its share of costs incurred with respect to the development area.

A 25 year development and production period commences once the Contractor Group has made a commercial discovery and a development plan is adopted.

The following diagram illustrates the allocation of production under the terms of the Block 10BA PSC:



Of the "Total Oil Produced", "Operations Oil" is available to the Contractor Group for operational needs for the work performed under the PSC. Up to a stated maximum percentage of the "Net Available Oil" is available for cost recovery with the remainder allocated to "Profit Oil". Costs subject to cost recovery include all costs and expenditures incurred by the Contractor Group for exploration, development, production and decommissioning operations, as well as any other applicable costs and expenditures incurred directly or indirectly with these activities. The portion of Profit Oil available to the Contractor Group is based on a sliding scale with the portion allocated to the Contractor Group declining as the volume of Profit Oil increases.

A second tier Profit Oil payment is due to the Government when oil prices exceed a stated world oil price. The amount payable per barrel is calculated by multiplying the Contractor Group's share of Profit Oil by a stated percentage and by the prevailing oil price in excess of the contractually agreed threshold world oil price.

Blocks 7 and 8, Ethiopia (30% working interest)

In 2014, the Company and its partners completed drilling the El Kuran-3 appraisal well on Block 8 in the Somali region of Ethiopia. Although the El Kuran-3 well demonstrated some oil and gas potential, the Company did not consider it warranted further evaluation due to concerns over reservoir quality and commerciality. During the third quarter of 2014, the Company notified the Ethiopian Government and its partners that it intended to withdraw from Blocks 7 and 8.

Adigala Block, Ethiopia (10% working interest)

During the first quarter of 2015, the Company notified the Ethiopian Government and its partners of its decision to withdraw from Adigala.

South Omo Block, Ethiopia (15% working interest – following completion of Maersk farmout)

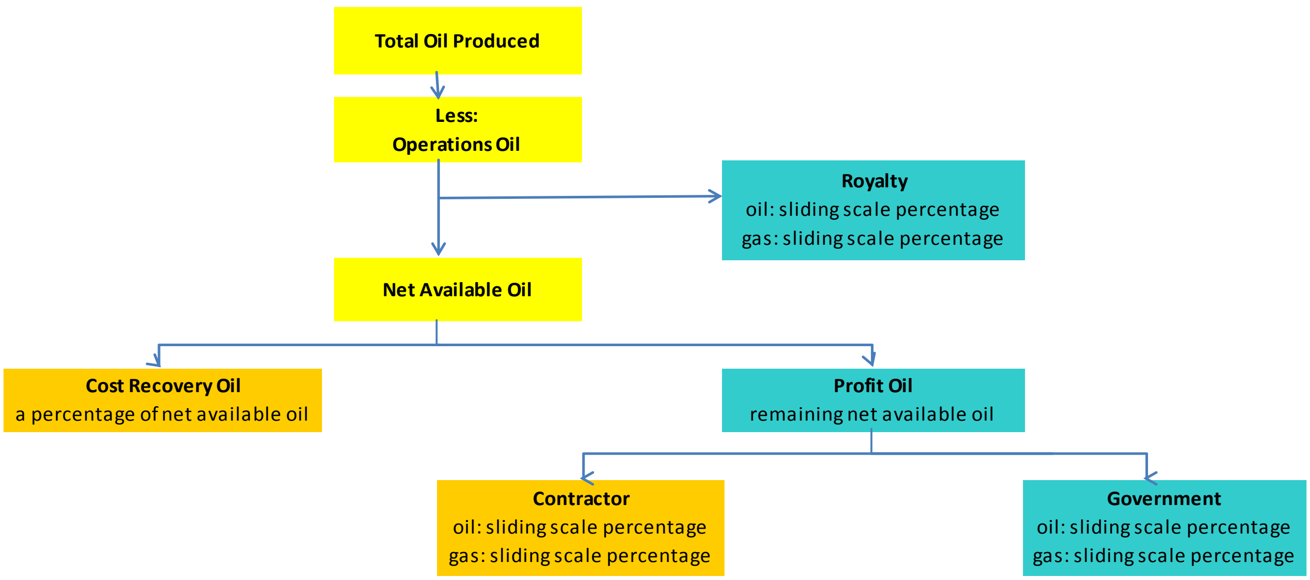
The South Omo Block PSA contemplates an initial four year exploration period and, at the option of the Contractor Group, two additional exploration periods of two years each. The Contractor Group elected to enter the second additional exploration period which expires in January 2017.

During the second additional exploration period, the Contractor Group is required to acquire an additional 200 kilometers of 2D seismic at a minimum expenditure of $2.0 million. In addition, the Contractor Group is required drill one exploratory well to a vertical depth of at least 3,000 meters. The minimum required expenditure for the well is $8.0 million. At the end of the second additional exploration period, the Contractor Group must relinquish the remainder of the original contract area that is not included within an appraisal area or development area.

The Ethiopian Government may elect to participate in any petroleum operations in any development area and acquire an interest of up to 15% of the total interest in that development area. The Ethiopian Government may exercise its participation rights within 120 days from the date a development plan is adopted. Upon electing to participate in a development area, the Government would assume responsibility for its share of costs incurred with respect to the development area.

A 25 year development and production period commences once the Contractor Group has made a commercial discovery and a development plan is adopted.

The following diagram illustrates the allocation of production under the terms of the South Omo Block PSC:



Of the "Total Oil Produced", "Operations Oil" is available to the Contractor Group for operational needs for the work performed under the PSC. The remaining oil is subject to a royalty, payable to the Ethiopian Minister of Mines and Energy, based on an increasing sliding scale as the rate of oil and/or gas increases

Up to a stated maximum percentage of the "Net Available Oil" is available for cost recovery with the remainder allocated to "Profit Oil". Costs subject to cost recovery include all costs and expenditures incurred by the Contractor Group for exploration, development, production and decommissioning operations, as well as any other applicable costs and expenditures incurred directly or indirectly with these activities. The portion of Profit Oil available to the Contractor Group is based on a sliding scale with the portion allocated to the Contractor Group declining as the volume of Profit Oil increases.

Rift Basin Area, Ethiopia (25% working interest – following completion of Maersk farmout)

The Rift Basin Area PSA contemplates an initial three year exploration period and, at the option of the Contractor Group, two additional exploration periods of two years each. The Contractor Group is currently in the initial exploration period which was set to expire in February 2016. The Government of Ethiopia has granted a twelve month extension to the initial exploration period, which will now expire in February 2017. During the initial exploration period, the Contractor Group is required to complete geological and geophysical activities, including acquisition of 8,000 square kilometers of full tensor gravity and 400 kilometers of 2D seismic with a minimum gross expenditure of $5.0 million. At the end of the initial exploration period, the Contractor Group must relinquish 25% of the original contract area.

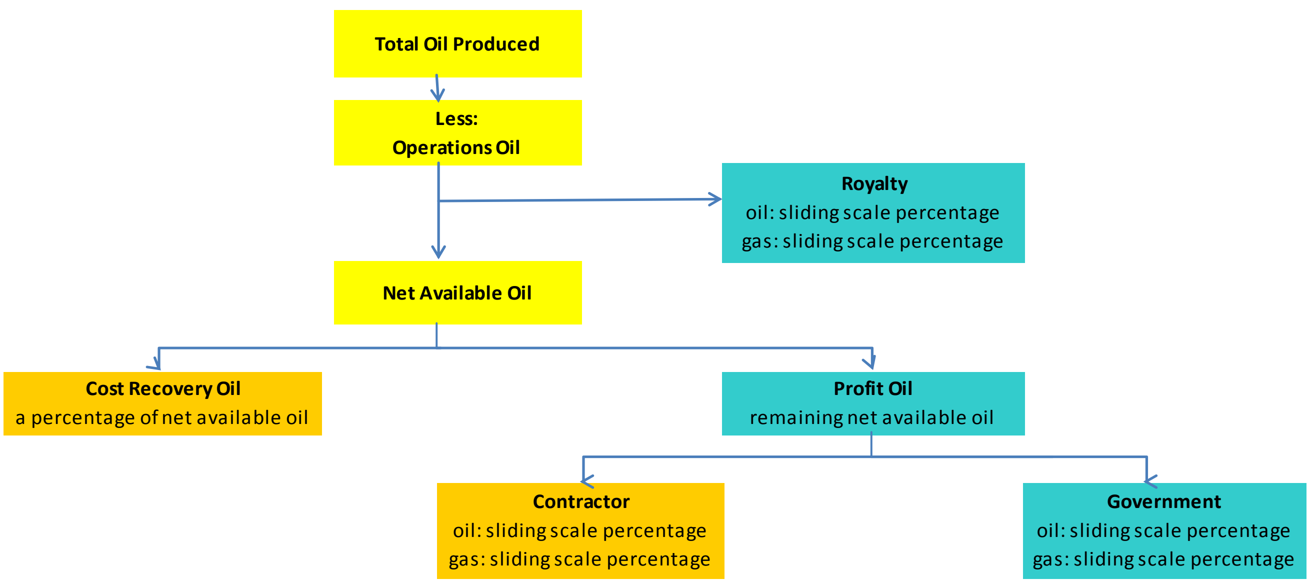
During the first additional exploration period, the Contractor Group is required to drill one exploratory well. The minimum required expenditure for the well is $7.5 million. If required for drilling, the Contractor Group is obligated to acquire an additional 400 kilometers of infill 2D seismic. At the end of the first additional exploration period, the Contractor Group must relinquish 25% of the original contract area.

During the second additional exploration period, the Contractor Group is required to drill one exploratory well. The minimum required expenditure for the well is $7.5 million. At the end of the second additional exploration period, the Contractor Group must relinquish the remainder of the original contract area that is not included within an appraisal area or development area.

The Ethiopian Government may elect to participate in any petroleum operations in any development area and acquire an interest of up to 18% of the total interest in that development area. The Ethiopian Government may exercise its participation rights within 120 days from the date a development plan is adopted. Upon electing to participate in a development area, the Government would assume responsibility for its share of costs incurred with respect to the development area.

A 25 year development and production period commences once the Contractor Group has made a commercial discovery and a development plan is adopted.

The following diagram illustrates the allocation of production under the terms of the Rift Basin Area PSC:



Of the "Total Oil Produced", "Operations Oil" is available to the Contractor Group for operational needs for the work performed under the PSC. The remaining oil is subject to a royalty, payable to the Ethiopian Minister of Mines and Energy, based on an increasing sliding scale as the rate of oil and/or gas increases

Up to a stated maximum percentage of the "Net Available Oil" is available for cost recovery with the remainder allocated to "Profit Oil". Costs subject to cost recovery include all costs and expenditures incurred by the Contractor Group for exploration, development, production and decommissioning operations, as well as any other applicable costs and expenditures incurred directly or indirectly with these activities. The portion of Profit Oil available to the Contractor Group is based on a sliding scale with the portion allocated to the Contractor Group declining as the volume of Profit Oil increases.

Dharoor and Nugaal Valley Blocks, Puntland (Somalia)
In June 2015, the Company and its joint venture partners notified the Government of Puntland (Somalia) of their decision to withdraw from the Nugaal Block and Dharoor Block PSAs

Disclosure of Reserves Data and Other Oil and Gas Information
For further information, please refer to Africa Oil's Statement of Reserves Data and Other Oil and Gas Information for fiscal year ended December 31, 2015 (Form NI 51-101F1) and the Report of Management and Directors on Oil and Gas Disclosure (Form NI 51-101F3), filed under the Company's profile on the SEDAR website at www.sedar.com, copies of which are attached hereto as Schedules A and B, respectively.

RISK FACTORS

The Company's operations are subject to various risks and uncertainties, including, but not limited to, those listed below.

International Operations
AOC participates in oil and gas projects located in emerging markets, which includes Ethiopia, and Kenya. Oil and gas exploration, development and production activities in these emerging markets are subject to significant political and economic uncertainties that may adversely affect AOC's operations. Uncertainties include, but are not limited to, the risk of war, terrorism, civil unrest, expropriation, civil unrest, nationalization, renegotiation or nullification of existing or future concessions and contracts, the imposition of international sanctions, a change in crude oil or natural gas pricing policies, a change in taxation policies, and the imposition of currency controls. These uncertainties, all of which are beyond AOC's control, could have a material adverse effect on AOC's business, prospects and results of operations. In addition, if legal disputes arise related to oil and gas concessions acquired by AOC, AOC could be subject to the jurisdiction of courts other than those of Canada. AOC's recourse may be very limited in the event of a breach by a government or government authority of an agreement governing a concession in which AOC acquires an interest. AOC may require licenses or permits from various governmental authorities to carry out future exploration, development and production activities. There can be no assurance that AOC will be able to obtain all necessary licenses and permits when required.

Different Legal System and Litigation

AOC's oil production and exploration activities are located in countries with legal systems that in various degrees differ from that of Canada. Rules, regulations and legal principles may differ both relating to matters of substantive law and in respect of such matters as court procedure and enforcement. Almost all material production and exploration rights and related contracts of AOC are subject to the national or local laws and jurisdiction of the respective countries in which the operations are carried out. This means that AOC's ability to exercise or enforce its rights and obligations may differ between different countries and also from what would have been the case if such rights and obligations were subject to Canadian law and jurisdiction.

AOC's operations are, to a large extent, subject to various complex laws and regulations as well as detailed provisions in concessions, licenses and agreements that often involve several parties. If AOC were to become involved in legal disputes in order to defend or enforce any of its rights or obligations under such concessions, licenses, agreements or otherwise, such disputes or related litigation may be costly, time consuming and the outcome may be highly uncertain. Even if AOC would ultimately prevail, such disputes and litigation may still have a substantially negative effect on AOC and its operations.

Financial Statements Prepared on a Going Concern Basis
AOC's financial statements have been prepared on a going concern basis under which an entity is considered to be able to realize its assets and satisfy its liabilities in the ordinary course of business. AOC's operations to date have been primarily financed by equity financing. AOC's future operations may be dependent upon the identification and successful completion of additional equity or debt financing, the achievement of profitable operations or other transactions. There can be no assurances that AOC will be successful in completing additional financings, achieving profitability or completing future transactions. The consolidated financial statements do not give effect to any adjustments relating to the carrying values and classification of assets and liabilities that would be necessary should AOC be unable to continue as a going concern.

Shared Ownership and Dependency on Partners
AOC's operations are, to a significant degree, conducted together with one or more partners through contractual arrangements. In such instances, AOC may be dependent on, or affected by, the due performance of its partners. If a partner fails to perform, AOC may, among other things, risk losing rights or revenues or incur additional obligations or costs in order to itself perform in place of its partners. AOC and its partners may also, from time to time, have different opinions on how to conduct certain operations or on what their respective rights and obligations are under a certain agreement. If a dispute were to arise with one or more partners relating to a project, such dispute may have significant negative effects on AOC's operations relating to such project.

Uncertainty of Title
Although the Company conducts title reviews prior to acquiring an interest in a concession, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise that may call into question the Company's interest in the concession. Any uncertainty with respect to one or more of the Company's concession interests could have a material adverse effect on the Company's business, prospects and results of operations.

Risks Relating to Concessions, Licenses and Contracts
AOC's operations are based on a relatively limited number of concession agreements, licenses and contracts. The rights and obligations under such concessions, licenses and contracts may be subject to interpretation and could also be affected by, among other things, matters outside the control of AOC. In case of a dispute, it cannot be certain that the view of AOC would prevail or that AOC otherwise could effectively enforce its rights which, in turn, could have significantly negative effects on AOC. Also, if AOC or any of its partners were deemed not to have complied with their duties or obligations under a concession, license or contract, AOC's rights under such concessions, licenses or contracts may be relinquished in whole or in part.

Competition
The petroleum industry is intensely competitive in all aspects including the acquisition of oil and gas interests, the marketing of oil and natural gas, and acquiring or gaining access to necessary drilling and other equipment and supplies. AOC competes with numerous other companies in the search for and acquisition of such prospects and in attracting skilled personnel. AOC's competitors include oil companies which have greater financial resources, staff and facilities than those of AOC and its partners. AOC's ability to discover reserves in the future will depend on its ability to successfully explore its present properties, to select and acquire suitable producing properties or prospects on which to conduct future exploration and to respond in a cost-effective manner to economic and competitive factors that affect the distribution and marketing of oil and natural gas. AOC's ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

Oil and natural gas producers are also facing increased competition from alternative forms of energy, fuel and related products that could have a material adverse effect on AOC's business, prospects and results of operations.

Risks Inherent in Oil and Gas Exploration and Development
Oil and gas operations involve many risks which even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of AOC depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that AOC will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, AOC may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that expenditures made on future exploration by AOC will result in discoveries of oil or natural gas in commercial quantities or that commercial quantities of oil and natural gas will be discovered or acquired by AOC. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While close well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

AOC's business is subject to all of the risks and hazards inherent in businesses involved in the exploration for, and the acquisition, development, production and marketing of, oil and natural gas, many of which cannot be overcome even with a combination of experience and knowledge and careful evaluation. The risks and hazards typically associated with oil and gas operations include fire, explosion, blowouts, sour gas releases, pipeline ruptures and oil spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment or personal injury.

Well-flow Test Results
Drill stem tests are commonly based on flow periods of 1 to 5 days and build up periods of 1 to 3 days. Pressure transient analysis has not been carried out on all well tests and the results should therefore be considered as preliminary. Well test results are not necessarily indicative of long-term performance or of ultimate recovery.

Capital Requirements
To finance its future acquisition, exploration, development and operating costs, the Company may require financing from external sources, including from the issuance of new shares, issuance of debt or execution of working interest farm-out agreements. There can be no assurance that such financing will be available to the Company or, if available, that it will be offered on terms acceptable to the Company. If additional financing is raised through the issuance of equity or convertible debt securities, control of the Company may change and the interests of shareholders in the net assets of the Company may be diluted. If unable to secure financing on acceptable terms, the Company may have to cancel or postpone certain of its planned exploration and development activities which may ultimately lead to the Company's inability to fulfill the minimum work obligations under the terms of its various PSAs. Availability of capital will also directly impact the Company's ability to take advantage of acquisition opportunities.

Environmental Regulation
Drilling for and production, handling, transporting and disposing of oil and gas and petroleum by-products are subject to extensive regulation under national and local environmental laws, including those of the countries in which AOC currently operates. Environmental regulations may impose, among other things, restrictions, liabilities and obligations in connection with water and air pollution control, waste management, permitting requirements and restrictions on operations in environmentally sensitive areas. Environmental protection requirements have not, to date, had a significant effect on the capital expenditures, results of operations and competitive position of AOC. However, environmental regulations are expected to become more stringent in the future and costs associated with compliance are expected to increase. Any penalties or other sanctions imposed on AOC for non-compliance with environmental regulations could have a material adverse effect on AOC's business, prospects and results of operations.

Availability of Equipment and Staff
AOC's oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment and qualified staff in the particular areas where such activities are or will be conducted. AOC currently leases all the drilling rigs used for its exploration and development activities. Shortages of such equipment or staff may affect the availability of such equipment to AOC and may delay AOC's exploration and development activities and result in lower production.

Reliance on Operators or Key Employees
The loss of the services of such key personnel could have a material adverse effect on AOC's business, prospects and results of operations. AOC has not obtained key person insurance in respect of the lives of any key personnel. In addition,

competition for qualified personnel in the oil and gas industry is intense and there can be no assurance that AOC will be able to attract and retain the skilled personnel necessary for operation and development of its business. Success of AOC is largely dependent upon the performance of its management and key employees.

Prices, Markets and Marketing of Crude Oil and Natural Gas
Oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, all of which are beyond the control of AOC. World prices for oil and natural gas have fluctuated widely in recent years. Any material decline in prices could have an adverse affect on AOC's business and prospects.

Early Stage of Development
AOC has conducted oil and gas exploration and development activities for a relatively short period. There is limited financial, operational and other information available with which to evaluate the prospects of AOC. There can be no assurance that AOC's operations will be profitable in the future or will generate sufficient cash flow to satisfy its working capital requirements.

Risks Relating to Infrastructure
Africa Oil is dependent on available and functioning infrastructure relating to the properties on which it operates, such as roads, power and water supplies, pipelines and gathering systems. If any infrastructure or systems failures occur or do not meet the requirements of Africa Oil, Africa Oil's operations may be significantly hampered. Kenya has limited oil infrastructure and no export facilities currently in place. The discoveries in Blocks 10BB and 13T are remote and cannot be delivered to market without significant infrastructure investment. New build pipeline infrastructure and road upgrades will be required to permit field development and production export for these resources. Whilst there may be outline plans for this new infrastructure, there is currently no firm commitment or government approval.

Current Global Financial Conditions
Global financial conditions have always been subject to volatility. Access to public financing has been negatively impacted by sovereign debt concerns in Europe and the United States, as well as concerns over global growth rates and conditions. These factors may impact the ability of the Company to obtain equity or debt financing in the future, and, if obtained, on terms favorable to the Company. Increased levels of volatility and market turmoil can adversely impact the Company's operations and the value and the price of the common shares could be adversely affected.

Foreign Currency Exchange Rate Risk
The Company is exposed to changes in foreign exchange rates as expenses in international subsidiaries, oil and gas expenditures, or financial instruments may fluctuate due to changes in rates. The Company's exposure is partially offset by sourcing capital projects and expenditures in US dollars. The Company had no forward exchange contracts in place as at December 31, 2015.

Liquidity Risk
Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. Liquidity describes a company's ability to access cash. Companies operating in the upstream oil and gas industry, during the exploration phase, require sufficient cash in order to fulfill their work commitments in accordance with contractual obligations and to be able to potentially acquire strategic oil and gas assets.

The Company will potentially issue debt or equity and enter into farmout agreements with joint venture partners to ensure the Company has sufficient available funds to meet current and foreseeable financial requirements. The Company actively monitors its liquidity to ensure that its cash flows and working capital are adequate to support these financial obligations and the Company's capital programs. The Company will also adjust the pace of its exploration activities to manage its liquidity position.

Credit Risk
Credit risk is the risk of loss if counterparties do not fulfill their contractual obligations. The majority of our credit exposure relates to amounts due from our joint venture partners. The risk of the Company's joint venture partners defaulting on their obligations per their respective joint operating and farmout agreements is mitigated as there are contractual provisions allowing the Company to default joint venture partners who are non-performing and reacquire any previous

farmed out working interests. The maximum exposure for the Company is equal to the sum of its cash, restricted cash, and accounts receivable. A portion of the Company's cash is held by banks in foreign jurisdictions where there could be increased exposure to credit risk.

Conflict of Interests

Certain directors of AOC are also directors or officers of other companies, including oil and gas companies, the interests of which may, in certain circumstances, come into conflict with those of AOC. If and when a conflict arises with respect to a particular transaction, the affected directors must disclose the conflict and abstain from voting with respect to matters relating to the transaction. All conflicts of interest will be addressed in accordance with the provisions of the BCBCA and other applicable laws.

The BCBCA provides that in the event that a director has a material interest in a contract or proposed contract or agreement that is material to the issuer, the director must disclose his interest in such contract or agreement and refrain from voting on any matter in respect of such contract or agreement, subject to and in accordance with the BCBCA. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the BCBCA.

Limitation of Legal Remedies

Securities legislation in certain of the provinces and territories of Canada provides purchasers with various rights and remedies when a reporting issuer's continuous disclosure contains a misrepresentation and ongoing rights to bring actions for civil liability for secondary market disclosure. Under the legislation, the directors would be liable for a misrepresentation. It may be difficult for investors to collect from the directors resident outside Canada on judgments obtained in courts in Canada predicated on the purchaser's statutory rights and on other civil liability provisions of Canadian securities legislation.

Selling Off of Shares

To the extent that any issued and outstanding Company Shares are sold into the market, there may be an oversupply of shares and an undersupply of purchasers. If this occurs the market price for the Company Shares may decline significantly and investors may be unable to sell their shares at a profit, or at all.

Industry Regulatory

Existing regulations in the oil industry, and changes to such regulations, may present regulatory and economic barriers to the purchase and use of certain products, which may significantly reduce the Company's revenues.

Environmental and Social Policies

Africa Oil Corp. is committed to ensuring that its operational activities, and those of its Joint Venture partners, comply with the IFC's Performance Standards and the World Bank's EHS Standards through the implementation of a range of Health, Safety, Environmental and Community systems, plans and procedures. Our commitment to meet these Standards is set out in documentation publicly available on the Company's website and is reviewed on a six monthly basis by an Independent Monitoring Group, whose report is again published on the website.

The objective of Africa Oil's Environmental, Social and Governance strategy is to address the challenge of sustainability – delivering value to its shareholders, providing economic and social benefits to communities while concurrently minimising its environmental footprint. The Company views its commitment to corporate responsibility as a strategic advantage that enables it to access and effectively manage new business opportunities. Africa Oil is committed to providing a safe, healthy, and transparent environment for employment, production, and sharing of the economic benefits that flow from its regional presence.

Environmental Considerations

The Company's oil and gas operations are located in regions where there are numerous environmental regulations including restrictions on where and when oil and gas operations can occur, regulations on the release of substances into groundwater, atmosphere and surface land and the potential routing of pipelines or location of production facilities. All such regulations are strictly followed and our operations are undertaken in accordance with the IFC Performance Standards. The Company could potentially be liable for contamination on properties acquired and it attempts to mitigate the risk of inheriting environmental liabilities when conducting due diligence on these acquisition opportunities. Breach of environmental regulations in any of the regions in which Africa Oil operates could result in restrictions or cessation of operations and the imposition of fines and penalties.

Social Policies

Africa Oil is committed to building a legitimate 'social license to operate' in the communities and countries in which it operates. The Company sees this as an essential foundation for its business activity. Africa Oil will therefore enter into dialogue and engagement with key stakeholders, conducted in the spirit of transparency and good faith, at all stages of company activities. Africa Oil will ensure that its operations meets the IFC Performance Standards in terms of its social impacts, mitigation and compensation. The Company also has contractual obligations to support community development initiatives under its PSAs. Through ongoing stakeholder engagement initiatives reflecting local priorities are identified and supported across three key areas: community infrastructure, sustainable livelihoods and economic development. Africa Oil contributes to, and works closely with, the Lundin Foundation on many of these.

The Lundin Foundation is a registered Canadian non-profit organization that provides grants and risk capital to organizations dedicated to alleviating poverty through economic growth in developing countries. The Company's engagement with the Lundin Foundation is a key component of the Company's wider ESG strategy in East Africa.

ITEM 5 CAPITAL STRUCTURE AND DIVIDENDS

The Company's common shares entitle the holders thereof to receive notice of and to attend at all meetings of shareholders, with each share entitling the holder to one vote on any resolution to be passed at such shareholders' meeting. The holders of common shares are also entitled to dividends if, as and when declared by the Board of Directors of the Company. Upon the liquidation, dissolution or winding up of the Company, the holders of the common shares are entitled to receive the remaining assets of the Company available for distribution to the shareholders.

As of December 31, 2015 the Company had an aggregate of 456,417,074 common shares issued and outstanding. The Company has unlimited authorized capital of common shares without par value of which, as at February 26, 2016, 456,417,074 common shares were issued and outstanding as fully paid and non-assessable.

DIVIDENDS

There are no restrictions which prevent the Company from paying dividends. Africa Oil has not paid dividends to date on its common shares and has no plans to pay dividends in the near future. Any decision to pay dividends in the future will be based on the Company's earnings and financial requirements and other factors which its board of directors may consider appropriate in the circumstances.

ITEM 6 MARKET FOR SECURITIES

TRADING PRICE AND VOLUME

The common shares of the Company trade on the Toronto Stock Exchange and on Nasdaq Stockholm under the trading symbol "AOI".

The following table sets out the price range for and trading volume of the common shares on Nasdaq Stockholm, on a monthly basis, from January 1, 2015 to December 31, 2015:

Month	High (SEK)(1)	Low (SEK) (1)	Volume
January 2015	18.59	15.05	45,619,956
February 2015	22.97	15.72	128,490,000
March 2015	16.91	12.02	63,357,352
April 2015	18.50	12.35	88,524,376
May 2015	19.09	16.62	43,376,108
June 2015	17.98	14.05	32,070,872
July 2015	15.38	12.07	48,390,292
August 2015	13.25	10.60	42,446,180
September 2015	12.84	9.37	38,923,188
October 2015	13.55	9.85	53,149,736
November 2015	16.50	10.50	76,972,312
December 2015	13.34	10.68	41,282,896

(1) The Company's common share prices above are quoted in Swedish Krona ("SEK").

The following table sets out the price range for and trading volume of the common shares on the TSX on a monthly basis, for the year ended December 31, 2015:

Month	High (CAD$)	Low (CAD$)	Volume
January 2015	2.74	2.10	10,147,247
February 2015	3.27	2.32	12,722,751
March 2015	2.59	1.80	12,911,315
April 2015	2.70	1.82	1,364,7204
May 2015	2.81	2.51	6,941,562
June 2015	2.66	2.11	3,030,267
July 2015	2.27	1.80	4,108,762
August 2015	2.10	1.67	3,782,976
September 2015	1.95	1.45	3,058,773
October 2015	2.10	1.56	2,657,741
November 2015	2.45	1.61	3,814,015
December 2015	2.11	1.73	2,498,525

ITEM 7 DIRECTORS AND OFFICERS

NAME AND OCCUPATION

The table below states the names, province or state and country of residence of each of the directors and executive officers of the Company, the principal occupations in which each has been engaged during the last five years, and the periods during which each has served as a director or executive officer.

Name, province or state and country of residence	Position(s) Held in the Company	Principal Occupation During the Past Five Years
Keith C. Hill Florida, USA	Director since October 16, 2006 Chief Executive Officer since March 30, 2009 President since October 20, 2009	Currently Chairman of ShaMaran Petroleum Corp., Petro Vista Energy Corp. and Africa Energy Corp.; director of BlackPearl Resources Ltd.; director of Tyner Resources Ltd.; director of TAG Oil Ltd.; formerly President and Chief Executive Officer of Pearl Exploration and Production Ltd. (now BlackPearl Resources Ltd.), Valkryies Petroleum Corp. and Bayou Bend Petroleum (now ShaMaran Petroleum Corp.).
Gary S. Guidry Alberta, Canada	Director since June 23, 2008	President & CEO and director of GranTierra Energy Inc.; Director of ShaMaran Petroleum Corp.; former President and CEO, director, and Head of Chad Business for Glencore E&P (Canada) Inc. (formerly Caracal Energy Inc.); former director of TransGlobe Energy Corporation; former director of Zodiac Exploration Inc.; former President and CEO of Orion Oil & Gas Corporation (January 2010 to June 2011) and of Tanganyika Oil Company Ltd. (May 2005 to April 2009).
John H. Craig Ontario, Canada	Director since June 19, 2009	Mr. Craig is a practising securities lawyer and senior counsel at the firm Cassels Brock & Blackwell LLP. He is also currently a director of Lundin Mining Corporation, BlackPearl Resources Ltd., Corsa Coal Corp. and Consolidated HCI Holdings Corporation. He is a former director of Denison Mines Corp., Sirocco Mining Inc. (formerly Atacama Minerals Corp.) and Etrion Corporation.
Bryan M. Benitz United Kingdom	Director since September 29, 2009	Mr. Benitz is the former Vice Chairman and a director of Longreach Oil and Gas Ltd., the former Chairman of Kirrin Resources, Scandinavian Minerals Ltd., and of MagIndustries Corp. Mr. Benitz was a founding director of Tanganyika Oil Company Limited.
Andrew Bartlett United Kingdom	Director since May 27, 2015	Mr. Bartlett has over 35 years of experience in the Oil and Gas Industry, 20 of those with Shell. An experienced ex -investment banker based in London, Andrew was both the Global Head of Oil and Gas Project Finance and Global Head of Oil and Gas Mergers and Acquisitions at Standard Chartered Bank until July 2011. He is currently a board member of Impact Oil & Gas Plc, and a director of Bartlett Energy Advisers.

Name, province or state and country of residence	Position(s) Held in the Company	Principal Occupation During the Past Five Years
Ian Gibbs British Columbia, Canada	Director in 2006; Director from June 2008 to September 2009 Chief Financial Officer from October 2006 to March 2008; Chief Financial Officer since September 15, 2009	Mr. Gibbs is currently a director of Lundin Gold Inc. (formerly “Fortress Minerals Corp.”), Africa Energy Corp. and Petro Vista Energy Corp. He is also the former Chief Financial Officer of Valkryies Petroleum Corp., Tanganyika Oil Company Ltd. and ShaMaran Petroleum Corp. (formerly, Bayou Bend Petroleum Ltd.).
Dr. Paul Martinez Alberta, Canada	Vice President, Exploration since March 14, 2011	Before joining the Company in 2011, Dr. Martinez was Director International Business Development for Occidental Oil & Gas since 2009, and Vice President Exploration, Occidental Libya Oil & Gas BV from 2007 to 2009.
Mark Dingley Nairobi, Kenya	Vice President, Operations since July 30, 2014	Currently also the President of Africa Oil Ethiopia B.V. and was Chief Operating Officer of Africa Energy Corp. from May 1, 2013 to January 31, 2016. Before joining the Company in 2013, Mr. Dingley was the Vice President, Middle East Operations for Talisman Energy Inc.
Tim Thomas Alberta, Canada	Chief Operating Officer since April 17, 2015	Mr. Thomas has more than 35 years of industry experience and was most recently President and CEO of ArPetrol Ltd. and prior to that spent 18 years with Nexen Inc. While at Nexen, Mr. Thomas's roles included Senior Vice President Canadian Oil and Gas, Vice President Yemen and International Business Development as well as country manager positions in Yemen and the UK.
Alex Budden United Kingdom	Vice President External Relations since July 15, 2012	Mr. Alex Budden served as a Diplomat for the British Foreign & Commonwealth Office for 21 years. His international experience has seen him serve in Africa, Asia, the Middle East, Russia, the Balkans and North America. From 2005-2008 he was based in East Africa advising the British Government on political, security, social and economic issues in the region. From 2008-2012 he represented the British Government in Canada on commercial, environmental and energy security issues with a focus on the hydrocarbon and renewables sectors. Mr. Budden is also the Vice President External Relations for Africa Energy Corp., a director of the Lundin Foundation, and a member of the 'Strathmore Extractives Industry Centre' Advisory Council.

Each director of the Company holds office until the next annual general meeting or until his successor is duly elected or appointed, unless his office is earlier vacated in accordance with the articles of the Company or he becomes disqualified to act as a director.

There are currently four standing committees of the Board; namely, the Audit Committee, the Compensation Committee, the Corporate Governance and Nominating Committee and the Reserves Committee. The following table identifies the members of each of these Committees:

Audit Committee	Compensation Committee	Corporate Governance and Nominating Committee	Reserves Committee
Andrew Bartlett(Chair)	John H. Craig (Chair)	Gary S. Guidry (Chair)	Gary S. Guidry (Chair)
Gary S. Guidry	Bryan M. Benitz	Andrew Bartlett	Keith C. Hill
Bryan M. Benitz	Andrew Bartlett	John H. Craig	Andrew Bartlett

SECURITY HOLDINGS

As at December 31, 2015, the directors and executive officers of the Company, as a group, beneficially owned, directly or indirectly or exercise control or direction over 2,646,128 common shares, representing approximately 0.58% of the issued and outstanding common shares of the Company.

CEASE TRADE ORDERS

Other than as disclosed below, no director or officer or person holding a sufficient number of securities of the Company to affect materially the control of the Company, is, or within the past ten years before the date of this Annual Information Form has been, a director or officer of any other issuer that, while such person was acting in that capacity: (i) was the subject of a cease trade or similar order, or an order that denied the other issuer access to any exemptions under Canadian securities legislation, for a period of more than 30 consecutive days; (ii) was subject to an event that resulted in such an order after the person ceased to be a director or officer; (iii) became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or comprise with creditors or had a receiver, receiver-manager or trustee appointed to hold its assets; or (iv) was subject to such bankruptcy proceedings within a year of that person ceasing to act in that capacity.

Mr. John Craig was a director of Sirocco Mining Inc. ("Sirocco") until November 8, 2013. On October 13, 2014, RB Energy Inc. ("RB Energy") a successor company to Sirocco filed for protection under the Companies' Creditors Arrangement Act ("CCAA"). Although John Craig was never a director, officer or insider of RB Energy, he was a director of Sirocco within the 12 month period prior to RB Energy filing under the CCAA.

PERSONAL BANKRUPTCIES

During the ten years preceding the date of this AIF, no director, officer or shareholder holding a sufficient number of shares of the Company to affect materially the control of the Company, or a personal holding company of any such person, has become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or was subject to or instituted any proceeding, arrangement or compromise with creditors or had a receiver, receiver-manager or trustee appointed to hold his or her assets.

The foregoing information, not being within the knowledge of the Company, has been furnished by the respective directors, officers and any control shareholder of the Company individually.

PENALTIES OR SANCTIONS

No director or officer of the Company, or shareholder holding a sufficient number of shares of the Company to materially affect control of the Company, has been the subject of any penalties or sanctions imposed by a court relating to Canadian securities legislation or by a Canadian securities regulatory authority or has entered into a settlement agreement with a Canadian securities regulatory authority, or been subject to any other penalties or sanctions imposed by a court or regulatory body that would be likely to be considered important to a reasonable investor in making an investment decision.

CONFLICTS OF INTEREST

The Company's directors and officers may serve as directors or officers of other companies or have significant shareholdings in other resource companies and, to the extent that such other companies may participate in ventures in which the Company may participate, the directors of the Company may have a conflict of interest in negotiating and concluding terms respecting the extent of such participation. In the event that such a conflict of interest arises at a meeting of the Company's directors, a director who has such a conflict will abstain from voting for or against the approval of such participation, or the terms of such participation. From time to time, several companies may participate in the acquisition, exploration and development of natural resource properties, thereby allowing for their participation in larger programs, the involvement in a greater number of programs or a reduction in financial exposure in respect of any one program. It may also occur that a particular company will assign all or a portion of its interest in a particular program to another of these companies due to the financial position of the company making the assignment. In accordance with the laws of Canada, the directors of the Company are required to act honestly, in good faith and in the best interests of the Company. In determining whether or not the Company will participate in a particular program and the interest therein to be acquired by it, the directors will primarily consider the degree of risk to which the Company may be exposed and the financial position at that time.

The directors and officers of the Company are aware of the existence of laws governing the accountability of directors and officers for corporate opportunity and requiring disclosure by the directors of conflicts of interest and the Company will rely upon such laws in respect of any directors' and officers' conflicts of interest or in respect of any breaches of duty by any of its directors and officers. All such conflicts will be disclosed by such directors or officers in accordance with the Business Corporations Act (*British Columbia*) and they will govern themselves in respect thereof to the best of their ability in accordance with the obligations imposed upon them by law. Other than as disclosed above, the directors and officers of the Company are not aware of any such conflicts of interest in any existing or contemplated contracts with or transactions involving the Company.

ITEM 8 AUDIT COMMITTEE

Overview

The Audit Committee oversees the accounting and financial reporting processes of the Company and its subsidiaries and all audits and external reviews of the financial statements of the Company on behalf of the Board, and has general responsibility for oversight of internal controls, accounting and auditing activities of the Company and its subsidiaries. All auditing services and non-audit services to be provided to the Company by the Company's auditors are pre-approved by the Audit Committee. The Committee is responsible for examining all financial information, including annual and quarterly financial statements, prepared for securities commissions and similar regulatory bodies prior to filing or delivery of the same. The Audit Committee also oversees the annual audit process, quarterly review engagements, the Company's internal accounting controls, the Code of Business Conduct and Ethics, any complaints and concerns regarding accounting, internal controls or auditing matters and the resolution of issues identified by the Company's external auditors. The Audit Committee recommends to the Board the firm of independent auditors to be nominated for appointment by the shareholders and the compensation of the auditors. The Audit Committee meets a minimum of four times per year. The Audit Committee's Charter is attached as Schedule "A" to this Circular.

Composition of the Audit Committee

Below are the details of each audit committee member, whether he/she is independent and financially literate as such terms are defined in National Instrument 52-110 – Audit Committees ("NI 52-110") and his/her education and experience as it relates to the performance of his/her duties as an audit committee member.

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Relevant Education and Experience

Each current member of the Audit Committee has extensive experience with financial statements, accounting issues, understanding internal controls and procedures for financial reporting and other related matters relating to public resource-based companies. The education and experience of each Audit Committee member that is relevant to the performance of his responsibilities as a member of the Audit Committee are as follows:

Member Name	Independent[(1)]	Financially Literate[(2)]	Education and Experience Relevant to Performance of Audit Committee Duties
Andrew Bartlett (Chair)	Yes	Yes	Mr. Bartlett has over 35 years of experience in the Oil and Gas Industry, 20 of those with Shell. An experienced ex -investment banker based in London, Andrew was both the Global Head of Oil and Gas Project Finance and Global Head of Oil and Gas Mergers and Acquisitions at Standard Chartered Bank until July 2011. He is currently a board member of Impact Oil & Gas Plc, and a director of Bartlett Energy Advisers.
Gary S. Guidry	Yes	Yes	Mr. Guidry is an Alberta registered P. Eng. and holds a B.Sc. in petroleum engineering from Texas A & M University. Mr. Guidry has attained financial experience and exposure to accounting and financial issues in his previous positions with a number of publicly-traded companies, including GranTierra Energy Inc., Glencore E&P (Canada) Inc. (formerly Caracal Energy Inc.), Griffiths Energy International Inc., Orion Oil & Gas Corporation, Tanganyika Oil Company Ltd., Calpine Natural Gas Trust and Alberta Energy Company.
Bryan M. Benitz	Yes	Yes	Mr. Benitz has been engaged in investment management and corporate development in Canada, the United States and Europe for over forty years in a variety of senior executive positions. Mr. Benitz has attained financial experience and exposure to accounting and financial issues while on boards and audit committees of various public companies. Mr. Benitz graduated from Fettes College in Edinburgh Scotland in 1951.

(1) A member of an audit committee is considered independent if the member has no director or indirect material relationship with the Company which could, in the view of the Board of Directors, reasonably interfere with the exercise of a member's independent judgment, or is otherwise deemed to have a material relationship under NI 52-110.

(2) An individual is financially literate if he/she has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Company's financial statements.

Audit Committee Oversight

Since the commencement of the Company's most recently completed financial year, there has not been a recommendation of the Audit Committee to nominate or compensate an external auditor that was not adopted by the board of directors.

Reliance on Certain Exemptions

Since the commencement of the Company's recently completed financial year, the Company has not relied on the exemptions contained in section 2.4 (*De Minimis Non-audit Services*), section 3.2 (*Initial Public Offerings*), section 3.4 (*Events Outside Control of Member*), section 3.5 (*Death, Disability or Resignation of Audit Committee Member*) or an exemption from NI 52-110, in whole or in part, granted under Part 8 (*Exemptions*) of NI 52-110.

Pre-Approval Policies and Procedures

The Audit Committee has adopted specific policies and procedures for the engagement of non-audit services as described in the Audit Committee Charter.

External Auditor Service Fees (By Category)

The following table discloses the fees billed to the Company by its external auditor during the last two fiscal years ended December 31, 2014 and December 31, 2015:

Financial Year Ending	Audit Fees[(1)] (CAD$)	Audit Related Fees[(2)] (CAD$)	Tax Fees[(3)] (CAD$)	All Other Fees[(4)] (CAD$)
December 31, 2015	188,750	11,814	181,836	38,619
December 31, 2014	164,700	12,487	49,780	22,978

Notes:

[(1)] The aggregate billed for audit services.

[(2)] Pertains to assurance and related services that are reasonably related to the performance of the audit or review of the Company's financial statements and that are not disclosed in the "Audit Fees" column.

[(3)] Pertains to profession services for tax compliance, restructuring, acquisitions, advice and planning.

[(4)] No fees were billed for professional services other than those listed in the other three columns.

ITEM 9 LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

Neither the Company nor its material subsidiaries and material properties are currently subject to any material legal proceedings or regulatory actions, except for those set out below.

The Company is a party to two separate court proceedings in Kenya initiated by Interstate Petroleum Ltd. ("IPL"), and certain parties related to IPL, as Applicants. Both proceedings, Judicial Review Number 30 of 2010 and Judicial Review Number 1 of 2012, involve a dispute concerning the administrative process that led to the issuance of exploration permits in respect of, amongst others, Blocks 10BA, 10BB, 12A and 13T. The primary Respondents to these proceedings include the Minister and the Ministry of Energy and Petroleum, Republic of Kenya. The Company and certain of its affiliates are named as Interested Parties.

Since 2012, IPL and certain of the related parties have also commenced numerous court applications and appeals in respect of these proceedings, including applications to appeal recent High Court decisions to the Kenyan Court of Appeal. These applications and appeals have either been struck by court order, or are the subject of further appeals and applications for stays of proceedings filed on behalf of the Company. In December 2014, the Company filed its record of appeal in respect of a High Court decision in Judicial Review Number 1 of 2012 allowing the Applicants to institute certain proceedings which the Company maintains have previously been adjudicated and settled. No date has been set for the hearing of the appeal. If the appeal is not allowed, the Company may be required to argue Judicial Review Number 1 of 2012 on its merits.

The Company has initiated its own court proceedings against IPL and certain parties related to IPL, including various applications for costs and Winding-Up Cause No. 1 of 2014. The Winding-Up proceeding is an application to cause IPL to be wound-up or "dissolved", which would terminate any further action in respect of the judicial review proceedings commenced by IPL. On July 2, 2015, by a Judgment issued by the High Court of Kenya in the winding up cause, the court ordered that IPL be wound up and the Official Receiver was appointed as the provisional liquidator. An appeal in respect of the winding up order was filed on behalf of IPL. The appeal was heard on December 8, 2015 and a decision is expected to be issued on March 16, 2016. In the interim, the Company is also proceeding with the execution of the winding up order.

All of these proceedings are working their way through the Kenyan judicial system. The Company will continue to pursue its remedies through the courts. In the interim, it will vigorously defend any application or appeal brought by the Applicants in any of these proceedings.

Regulatory Actions

No penalties or sanctions were imposed by a court relating to securities legislation or by a securities regulatory authority during the Company's recently completed financial year, nor were there any other penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision, nor were any settlement agreements entered into before a court relating to securities legislation or with a securities regulatory authority during the Company's recently completed financial year.

ITEM 10 INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director or executive director of the Company, or person or company that beneficially owns, directly or indirectly, or exercises control or direction over, more than 10% of the Company's common shares, nor any associate or affiliate of any such person, has any material interest, director or indirect, in any transaction within the three most recently completed financial years of the Company, or during the current financial year, that has materially affected or will materially affect the Company.

ITEM 11 TRANSFER AGENT

The transfer agent and registrar for the common shares of the Company in Canada is Computershare Trust Company of Canada, 510 Burrard Street, Vancouver, British Columbia. The registrar for the common shares of the Company in Sweden is Euroclear Sweden AB, 103 97 Stockholm, Sweden.

ITEM 12 MATERIAL CONTRACTS

The Company has not, within the last financial year, entered into any material contracts, nor are there any material contracts entered into before the last financial year that are still in effect, except for:

(i) Contracts entered into in the ordinary course of business; and
(ii) Investment Agreement ("Investment Agreement") made May 1, 2015 with Stampede Natural Resources S.A.R.L.

A copy of the Investment Agreement can be found on www.SEDAR.com.

ITEM 13 NAMES AND INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing made under NI 51-102 by the Company during the current financial year other than PricewaterhouseCoopers LLP, Africa Oil's auditors. PricewaterhouseCoopers LLP, the Company's auditors, are independent in accordance with the auditor's rules of professional conduct in Canada.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of Africa Oil or any associate or affiliate of Africa Oil.

ITEM 14 ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Company's securities, options to purchase securities and interests of insiders in material transactions, where applicable, is contained in the Company's information circular for its most recent annual meeting of securityholders that involved the election of directors.

Additional financial information is provided in the Company's audited consolidated financial statements as at and for the year ended December 31, 2015 and the MD&A.

SCHEDULE A

AFRICA OIL CORP.

(the "Reporting Issuer" or the "Company")

FORM NI 51-101F1
STATEMENT OF RESERVES DATA AND
OTHER OIL AND GAS INFORMATION
For fiscal year ended December 31, 2015

(This is the form referred to in item 1 of National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Terms for which a meaning is given in NI 51-101 have the same meaning in this Form 51-101F1.)

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PART 1 DATE OF STATEMENT

Item 1.1 Relevant Dates

1. The date of this report and statement is: February 26, 2016.
2. The Effective Date of information provided in this statement is as of the Company's most recently completed fiscal year ended: December 31, 2015.

PART 6 OTHER OIL AND GAS INFORMATION

Item 6.1 Oil and Gas Properties and Wells

The Company's oil and gas properties are all located onshore in Kenya and Ethiopia.

In Kenya, the Company currently holds working interests in four production sharing contacts ("PSC") with the Government of the Republic of Kenya in the Tertiary Rift play: Blocks 10BB, 13T, 10BA and 12A. The exploration areas covered by these PSCs are on trend with the significant Tullow Oil plc ("Tullow") Albert Graben oil discovery in neighboring Uganda where Tullow is working with the Government of Uganda and its joint venture partners, CNOOC and Total to complete a Lake Albert basin wide development plan which would include the construction of an oil export pipeline to the coast of East Africa, potentially through Kenya. Multiple discoveries have been made by the Tullow /Africa Oil Corp. joint venture in Blocks 10BB and 13T.

Also in Kenya, the Company holds a working interest in the Block 9 PSC, located in the Anza Graben play, which is a Mesozoic basin related to similar Mesozoic basins located in southern Sudan (Muglad Basin) where the petroleum system is proven and productive. The Muglad Basin is a potential analogue and provides calibration for the analysis of the prospectivity of this Block.

In Ethiopia, the Company currently has an interest in two PSCs with the Government of the Federal Democratic Republic of Ethiopia in the Tertiary Rift play: the South Omo and Rift Basin Area PSCs which are an extension of the Tertiary Rift trend to the north of the four Kenyan Tertiary Rift blocks.

Also in Ethiopia, the Company has an interest in the Block 7/8 PSC in the Ogaden Basin and the Adigala Blocks PSC. However, the Company has notified its joint venture partners of its decision to withdraw from these Blocks. Accordingly, the Company will not participate in any further exploration activities on these blocks.

Item 6.2 Properties with No Attributed Reserves

The Company's working interest at the preparation date of this report in the various concessions is outlined in the table below together with the gross and net acreage of each. Between the effective date and preparation date of this report, the Company completed a farmout transaction with Maersk Olie og Gas A/S ("Maersk") whereby it farmed out 50% of its interests in Blocks 10BB, 13T, 10BA in Kenya and the South Omo and Rift Basin Blocks in Ethiopia.

Region	Production Sharing Contracts	Operator	Current Working Interest (1,2)	Gross Acreage (km^2)	Net Acreage (3) (km^2)
Kenya	Block 10BB	Tullow	25%	6,172	1,543
	Block 13T	Tullow	25%	4,719	1,180
	Block 10BA	Tullow	25%	15,811	3,953
	Block 12A	Tullow	20%	15,235	3,047
	Block 9	Africa Oil Corp.	50%	15,782	7,891
Ethiopia	South Omo	Tullow	15%	22,034	3,305
	Rift Basin	Africa Oil Corp.	25%	42,519	10,630
	Blocks 7 and 8 (4)	New Age	30%	21,767	6,530
	Adigala (5)	New Age	10%	20,200	2,020

(1) Net Working Interests are subject to back-in rights, if any, of respective governments.

(2) Tullow's interest in Block 12A reflects a farmout to Delonex that completed subsequent to the Effective Date.

(3) Net acreage is calculated by multiplying Gross Acreage by the Current Working Interest.

(4) During the third quarter of 2014, the Company notified the Ethiopian Government and its partners of its decision to withdraw from Blocks 7 and 8.

(5) During the first quarter of 2015, the Company notified the Ethiopian Government and its partners of its decision to withdraw from Adigala.

The principal work commitments, timing of completion and minimum expenditures to be incurred during the current exploration period of each of the respective Production Sharing Contracts are listed in the following tables:

Region	**Block**	**Exploration Period and Expiry**	**Work Commitments**	**Minimum Expenditures** (Gross $)	**Relinquishments end of current Period**
Kenya	10BB	Second Additional Period - July 24, 2017	3D seismic (250 km2) Drill 3 wells to min. 3000m	25.0 million	Final Relinquishment
Kenya	13T	Second Additional Period September 16, 2017	3D seismic (200 km2) Drill one well to min. 3000m	21.0 million	Final Relinquishment
Kenya	10BA	First Additional Period – April 26, 2016	1 Well or 45 km2 of 3D 1000 km 2D seismic or 50 km2 of 3D	17.0 million	25% of original contract area
Kenya	12A	First Additional Period– September 1, 2016	2D seismic (350 km) or 200 km2 of 3D 1 Well, minimum depth of 3,000m	21.0 million	25% of original contract area
Kenya	9	Second Additional Period- Extended to June 30, 2017	Drill one well	3.0 million	Final Relinquishment
Ethiopia	South Omo	Second Extension Term – January 14, 2017	2D seismic (200 km) Drill one well to a min. 3000m	10.0 million	Final relinquishment
Ethiopia	Rift Basin Area	Initial Term – 1 year extension to February 21, 2017	Geological, bathymetric geophysical and engineering studies 2D seismic (400 km) Full tensor gravity (8,000 km2)	5.0 million	25% of original contract area

Region	Block	Exploration Period and Expiry	Work Commitments	Minimum Expenditures (Gross $)	Relinquishments end of current Period
Ethiopia	7 & 8 (1)	18 month Appraisal Period expiring October 31, 2015	Prepare proposal for further appraisal	Pending review	Approval of appraisal area pending review by Ministry
Ethiopia	Adigala(2)	Second Extension Term – July 10, 2015	500km 2D seismic 1 well (contingent)	10.0 million	Final Relinquishment

(1) During the third quarter of 2014, the Company notified the Ethiopian Government and its partners of its decision to withdraw from Blocks 7 and 8.

(2) During the first quarter of 2015, the Company notified the Ethiopian Government and its partners of its decision to withdraw from Adigala.

Item 6.2.1 Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

As at the effective date of this report, reserves have yet to be attributed to any of the properties in which the Company holds an interest. Contingent resources have been attributed to the Lokichar Basin (Kenya) (Blocks 10BB and 13T).The key contingencies associated with the Lokichar Basin discoveries are as follows:

- Further data acquisition and analysis, including updated seismic mapping and depth conversion, to better characterise the reservoir extent and reduce sub-surface uncertainties in order to mature the sub-surface development plans;
- Definition of field development plans and infrastructure requirements; and
- Government approval and project sanction.

Seismic Mapping and Depth Conversion

The structural closure at each discovery is constrained by multi-vintage 2D seismic data and in some cases newly acquired 3D seismic data . These data are sufficient to define a structural closure at each discovery, however, there remains some uncertainty related to depth-conversion which may also impact the size of traps, particularly in fields that are constrained by only 1-2 wells. The area of closure and height of closure are dependent on the depth conversion methodology used. Most fields have confirmed the presence of multiple hydrocarbon pools. Within fields the oil-water contacts for some pools are well-constrained by pressure data and testing while others require additional drilling and testing to confirm the extent of pools. The resource estimates consider the uncertainty between the lowest known oil and structural spill-points. However, further appraisal drilling and well testing is required to reduce the uncertainty in the areal extent of reservoir pay zones.

Reservoir Characterisation

The Auwerwer and Lokhone Formations have been penetrated by the wells, drilled by AOC and its co-venturers. However log interpretation is challenging and there remains significant uncertainty with regard to the average and total thickness of the reservoir pay zones and reservoir quality (porosity, net-to-gross and hydrocarbon saturation).

Maturation of Subsurface Development Plans

Oil from the Lokichar Basin wells is a waxy crude (24 per cent to >35 per cent wax), with a wax appearance temperature in the region of 50°C to 70°C and a pour point of 40°C to 50°C. The use of artificial lift for production wells and hot water injection for secondary recovery is proposed. In order to validate this concept and optimize development, additional data gathering and evaluations are required including further production and inter-well interference testing, water injection trials, additional fluid and special core analyses, further G&G and modelling studies.

Field Development Plan and Infrastructure Requirements

The issues outlined above must be addressed to reduce the large uncertainty currently associated with the discoveries before field development plans can be finalized and submitted for approval.

Kenya has limited oil infrastructure and no export facilities currently in place. The discoveries in Blocks 10BB and 13T are remote and cannot be delivered to market without significant infrastructure investment.

The Lokichar Basin is in a remote part of Kenya, approximately 850 km from the most likely point of export at Lamu. New build pipeline infrastructure and road upgrades will be required to permit field development and production export for these resources. Whilst there may be outline plans for this new infrastructure, there is currently no firm commitment or government approval.

Government Approval and Project Sanction

All of the Kenyan discoveries are located within Exploration Contracts. The Government of Kenya has extended these Exploration Contracts to allow further exploration and appraisal. Conversion of these permits to production permits has yet to be agreed.

Regulatory support and approval will be required for the commercialization of the company's Kenyan Contingent Resources to proceed. In accordance with the Company's Production Sharing Contracts and joint venture agreements, field development plans must be agreed by the Company and its joint venture partners before submission for approval by the government.

Given the possible large scale of future development projects in Kenya to commercialize the Contingent Resources, significant capital requirements are anticipated which are potentially beyond the Company's current sources of capital. The Company may require financing from external sources, including issuance of new Shares, issuance of debt or disposition arrangements. There can be no assurance that such financing will be available to the Company or, if available, that it will be offered on terms acceptable to the Company.

Prior to project sanction for the areas in which the Company has an interest in Contingent Resources, numerous agreements and studies will need to be completed in addition to field development plans, including major engineering/procurement/construction agreements, environmental and social impact assessments, land acquisition agreements and community development plans.

Item 6.3 Forward Contracts

The Company is not party to any agreements relating to the transportation or marketing of oil and gas.

Item 6.5 Tax Horizon

The Company was not required to pay income taxes during 2015. Given the Company is in the exploration stage and does not currently have reserves, no reasonable estimate may be made as to when the Company will be required to pay income taxes in the future.

Item 6.6 Costs Incurred

The nets costs incurred by the Company in relation to the various geographic areas in which the Company operated during 2015 were as follows:

Geographic Region	Costs ($US million) Exploration
Ethiopia	0.8
Kenya	219

Item 6.7 Exploration, Appraisal and Development Activities

Gross Wells and Net Wells Completed During 2015

The Company's oil exploration and appraisal wells completed during 2015 are as follows:

Exploration and Appraisal Wells

Well/ Block		NET - Africa Oil	Gross Wells	Net Wells
Amosing-3	10BB	0.5	1	0.5
Ekales-2	13T	0.5	1	0.5
Ngamia-7	10BB	0.5	1	0.5
Amosing-4	10BB	0.5	1	0.5
Ngamia-8	10BB	0.5	1	0.5
Ngamia-9	10BB	0.5	1	0.5
Twiga-3	13T	0.5	1	0.5
Amosing 5, 5A	10BB	0.5	1	0.5
Emesek-1	13T	0.5	1	0.5
Etom-2	13T	0.5	1	0.5
Engomo-1	10BA	0.5	1	0.5
Cheptuket	12A	spud in 2015		
TOTAL			**11**	**5.5**

Most Important Current and Likely Exploration and Development Activities

As of December 31, 2015, the Company has been engaged in exploration and appraisal activities aimed at fulfilling or exceeding work commitments outlined in the table included in Item 6.2 above. The Company's assets are wholly located in East Africa. East Africa is a vastly under-explored region where renewed interest is being shown by a growing number of mid to large sized oil companies wishing to add to their exploration portfolios. The majority of the Company's assets are located in the East African Tertiary Rift Play, which is one of the last large unexplored rift basins. The Company acquired its interests in East Africa as several multi-billion barrel oil-prone basins were being discovered in Sudan and neighboring Uganda. The Company and partners have acquired extensive seismic programs over these assets and have identified a large inventory of prospects and leads within a vast exploration acreage position.

The Company has made a number of oil discoveries to date in the South Lokichar Basin (Blocks 10BB/13T Kenya) and is focusing its planned activities on ongoing appraisal and pre-development activities in this Basin.

The Company continues to perform necessary work and analyses to upgrade its assets in the South Lokichar basin and submitted a Draft Field Development Plan (“FDP”) in December 2015.

In light of the current and forecast short term oil price environment, the Company has worked closely with Tullow to focus the 2015 work program and budget on advancing the South Lokichar development in Blocks 10BB and 13T (Kenya) by undertaking activities aimed at increasing resource certainty. These activities include:

- Multiple appraisal/exploration wells in the South Lokichar Basin;
- Extended Well Testing (EWT’s) in the Amosing and Ngamia fields; and
- Reservoir and engineering studies (including extensive core analysis).

In addition, the Africa Oil - Tullow joint venture will continue to work closely with the Government of Kenya and the Uganda upstream partners to advance the regional oil export pipeline.

Outside the South Lokichar Basin, the Africa Oil - Tullow joint venture new basin opening exploration program included the Engomo-1 well and the Cheptuket well, currently drilling, in Block 12A, a PSC commitment well.

Given the changing focus of the 2015 work program to appraisal and development studies of the South Lokichar Basin discoveries, the Africa Oil – Tullow partnership has reduced the operations to utilize one drilling rig and plans to release this rig following the completion of the Cheptuket well.

Outside of the Africa Oil - Tullow joint venture blocks, the work program was focused on the Rift Basin Area Block in Ethiopia where a 2D seismic land and lake survey was completed.

2015 Activity Summary by Block

KENYA

The 2015 work program has been primarily focused on appraisal of the discoveries in the South Lokichar Basin with the following objectives; confirming reservoir quality and deliverability, resource size and definition, and advancement of the development plans, including the export pipeline. One drilling rig was active at the end of 2015 and is expected to be released in the first quarter of 2016. A limited number of potential basin opening wells were drilled in Kenya during 2015 outside of the discovered South Lokichar Basin.

Block 10BB and 13T

In January 2015, the Company announced that the acquisition of the large 951 square kilometre 3D seismic survey over the series of significant discoveries along the western basin bounding fault in the South Lokichar Basin was completed and processed data became available during the year. Evaluation of the 3D seismic continues, indicating significantly improved structural and stratigraphic definition and additional prospectivity not evident on the 2D seismic.

During the first quarter of 2015 in the Amosing field, the Amosing-3 appraisal well, located one kilometer northwest of the Amosing-1 discovery, well was drilled. The well encountered up to 140 meters of net oil pay and proved an extension of the field. Pressure data from the Amosing-3 well indicated connectivity in some reservoir horizons encountered in the Amosing-1, 2 & 2A wells. The Amosing-4 well, located approximately one kilometer southeast of the Amosing-1 well, was drilled to test the southern extent of the field and successfully encountered 27 meters of net oil pay in thick upper reservoir zones proving the significant down-dip extent of the field. In the third quarter of 2015, the Amosing-5A exploratory appraisal well was drilled as a test of an undrilled fault block. The well encountered an estimated 15 to 28 metres of net oil pay in a downflank position and successfully proved a northern extension to the Amosing field.

During the first half of 2015, in preparation for the EWTs, the Amosing-1 and Amosing-2A wells were successfully completed in five separate zones. Initial rig-less flow testing during clean-up flowed at a cumulative maximum rate of 5,600 and 6,000 bopd respectively. These results exceeded expectations, and demonstrated high quality reservoir sands which flowed 31 to 38 degree API dry oil under natural conditions. During the test the wells produced at a cumulative average constrained rate of 4,300 bopd under natural flow conditions. Pressure data from the two wells supports significant connected oil volumes and confirms lateral reservoir continuity, which is positive for the future development. A cumulative volume of 30,000 barrels of oil has been produced into storage. Water injection tests are being planned to further validate the viability of water flood reservoir management and the oil recovery assumptions.

During the first quarter of 2015, in the Ngamia field, the Company announced the completion of drilling the Ngamia-5, Ngamia-6 wells, in addition Ngamia-7 and Ngamia-8 appraisal wells were drilled. Ngamia-5 is located 500 metres northeast of the Ngamia-1 discovery well in a different fault compartment and encountered 160 to 200 metres net oil pay, which is amongst the highest of all the wells drilled in the basin to date. Ngamia-6 is located approximately 800 metres north of Ngamia-1 and in the same fault compartment as Ngamia-5 and encountered up to 135 metres net oil pay. Ngamia-7 well was drilled 1.2 kilometers east of Ngamia-3 and encountered up to 130 meters of net oil pay identifying a large eastern extension of the field that had been identified from the new 3D seismic survey. The Ngamia-8 appraisal was drilled and encountered up to 200 meters of net oil pay in line with pre-drill expectations. The well was positioned in the center of the Ngamia structure and static pressure data indicates the well is in pressure communication with the oil discovered in the neighbouring Ngamia-1A, Ngamia-3, Ngamia-5, Ngamia-6 and Ngamia-7 wells. During the second quarter of 2015, the drilling of the Ngamia-9 well was completed and encountered between 90 and 110m of pay in the Lokone and Auwerwer horizons.

During 2015 the partnership completed the Ngamia Extended Well Test production phase with approximately 38,000 barrels of oil produced. Five completed zones of the Ngamia-8 production well were tested individually at a cumulative rate of 2,400 bbl/d and all except the lowest zone produced without artificial lift. Communication between the producer well and an observation well, at a distance of approximately 500 metres, was also demonstrated. Water injection tests are being planned to further validate the viability of water flood reservoir management and the oil recovery assumptions.

Elsewhere in the Lokichar basin, during the first quarter of 2015, the Ekales-2 appraisal well reached a total depth of 4,059 meters and encountered an estimated 60-100 meters of net oil pay in the primary shallower objectives. This highly deviated well was also deepened to test the basin center stratigraphic play where it intersected sandstones with elevated pressures and 50 meters of oil bearing sands; however, operating conditions precluded logging and confirmation of any oil pay in this section. This was the first test of this exploration target and is very positive for the future upside potential of the South Lokichar Basin, above the significant oil resources already discovered.

The Etom-2 well was drilled in an undrilled fault block adjacent to the Etom oil discovery in Block 13T. The well encountered 102 metres of net oil pay in two columns. The objective of the well was to explore the north flank of the Etom structure in an untested fault block identified by recent 3D seismic. Oil samples, sidewall cores and wire line logging all indicate the presence of high API oil in the best quality reservoir encountered in the South Lokichar Basin to date. Discovering this thick interval of high quality oil reservoirs at Etom-2 further underpins the development options and resource base in the South Lokichar Basin. The result follows careful evaluation of 3D seismic data which was shot after the Etom-1 well completed drilling and demonstrates how the partnership has improved its understanding of the basin. This result also suggests significant potential in this underexplored part of the block as it is the most northerly well drilled in South Lokichar and is located close to the axis of the basin away from the basin-bounding fault. Accordingly, Tullow Oil plc and Africa Oil will review the resource potential of the greater Etom area and neighbouring prospects as part of a future exploration drilling program.

In the Twiga field the Twiga-3 exploratory appraisal well in Block 13T encountered sands within the Lokone Shale sequence that are interpreted as good quality oil bearing reservoir over a gross interval of 120 metres. This result will be assessed in future exploration and appraisal activities, stepping out into the South Lokichar basin to further define this encouraging additional oil potential.

During the first quarter of 2015, the Epir-1 exploration well was drilled to a total depth of 3,057 meters in the North Kerio Basin in Block 10BB, Kenya. The well encountered a 100 meter interval of wet hydrocarbon gas shows with florescence indicating the presence of an active petroleum system. The hydrocarbon shows were encountered primarily in rocks which are not of reservoir quality. The partnership is very encouraged the Epir-1 well has demonstrated a working hydrocarbon system in the Kerio Basin and technical work will now focus on identifying a prospect in the basin where there is a high chance of trapping hydrocarbons in reservoir quality rock.

During the fourth quarter of 2015, the Emesek-1 exploration well was drilled, testing the undrilled North Lokichar basin in Block 13T. The well reached a total depth of 3,000 metres without encountering commercial hydrocarbons and was plugged and abandoned.

In addition, the partnership has acquired over 1,100 metres of whole core from the South Lokichar wells and an extensive program of detailed core analysis continues. A key focus of the core program is to better assess oil saturation and to refine the recovery factors of the main reservoir sands.

Block 10BA

Prior to 2015 the Company and its operating partner on Block 10BA, Tullow, completed a 1,450 kilometer 2D seismic program, split evenly between onshore and offshore. After review of the newly-acquired seismic data partners selected the Engomo-1 Prospect to test a Tertiary rift basin in the northwestern corner of Block 10BA.

The Engomo-1 well was drilled in the first quarter of 2015 and was drilled to a total depth of 2,353 meters. The well encountered Tertiary-aged interbedded siltstones, sandstones and claystones, becoming more tuffaceous and tight until reaching a total depth in basement. No significant oil or gas shows were encountered and the well has been plugged and abandoned. The prevalence of tight facies in the wellbore may be due to the well's close proximity to the basin bounding fault. Future analysis will be focused on understanding how this result impacts the remaining prospectivity in the basin.

Block 12A

The Company and its partners on Block 12A completed a 707 kilometer 2D seismic acquisition program in 2014, progressed subsurface mapping in 2014. During 2015 partners reviewed the prospect inventory and results from a surface geological field survey that confirmed the presence of prospective Tertiary source rocks in areas surrounding the Kerio Valley. Based on subsurface and surface mapping the Cheptuket prospect was identified in the southern Kerio Valley and partners agreed to prepare the Cheptuket-1 for drilling. The Cheptuket-1 exploration well was spud on December 28, 2015 and was drilled to a depth of 3,080m before wireline and other evaluation logs commenced. Well results are currently under review.

Block 9

Block 9 is in the Cretaceous rift basin on trend with the South Sudan oil fields. In December 2013, the Company announced that it had drilled the Bahasi-1 well to a depth of 2,900 meters, encountering basement at 2,850 meters. The well encountered a thick section of Tertiary and Cretaceous inter-bedded sands and shales, but with only minor hydrocarbon shows. The Bahasi-1 well satisfied the remaining work commitment in the first additional exploration period under the Block 9 PSC, which expired in December 2013. The Company and its joint venture partner elected to enter the second additional exploration period under the PSC. In June 2014, the Company announced the Sala-1 well had resulted in a gas discovery. The Sala-1 drilled a large feature along the northern basin bounding fault in the Cretaceous Anza graben and encountered several sandstone intervals which had oil and gas shows. The well was drilled to a total depth of 3030 meters and petrophysical analysis indicated three zones of interest over a 1000 meter gross interval which were subsequently drill stem tested. An upper gas bearing interval tested dry gas at a maximum rate of 6 mmcf/d from a 25 meter net pay interval. The interval had net reservoir sand of over 125 meters and encountered a gas water contact so there is potential to drill up-dip on the structure where this entire interval will be above the gas-water contact. A lower interval tested at low rates of dry gas from a 50 meters potential net pay interval which can also be accessed at the up-dip location. It should also be noted that there were oil shows while drilling and small amounts of oil were recovered during drilling and testing which indicates there may be potential for oil down-dip on the structure.

In October 2014, the Company announced the Sala-2 appraisal well failed to find significant hydrocarbons updip from the Sala-1 gas discovery. There appears to be a stratigraphic or structural separation between the two wells. The Company is reviewing additional potential appraisal targets as well as on trend prospects in the block which has proven oil and gas generation.

In 2015 the Company applied for and received approval for an 18 month extension to the second and final exploration phase. During 2015 work progressed to evaluate the drilling results of Sala-1 and Sala-2 and to evaluate remaining prospectivity in the block with a focus on commercialization of prospective gas resources.

ETHIOPIA

South Omo Block

The South Omo Block is located in the northern portion of the Tertiary East African Rift trend where Africa Oil and their partners have made seven significant oil discoveries in Northern Kenya. In January 2013, the Company and its partners on the South Omo Block spudded the Sabisa-1 well which is located in the North Turkana Basin. The Sabisa-1 well was drilled to a preliminary total depth of 1,810 meters. Hydrocarbon indications in sands beneath a thick claystone top seal were recorded while drilling, but hole instability issues required the drilling of a sidetrack to comprehensively log and sample these zones of interest. The sidetrack was drilled to a total depth of 2,082 meters. The well encountered reservoir quality sands, oil shows and heavy gas shows indicating an oil prone source rock and thick shale section which should provide a good seals for the numerous fault bounded traps identified in the basin. Only the lowermost sands appeared to be in trapping configuration at Sabisa-1.

Based on the encouragement of the results of the Sabisa well, the Company decided to drill the nearby Tultule prospect, which was drilled to a total depth of 2,101 meters. The Tultule-1 well encountered a section similar to the nearby Sabisa-1 well in the upper portion of the well but the sands which appeared to be hydrocarbon bearing in the Sabisa-1 well were not present on the Tultule horst block feature with multiple volcanic units and shales in this section. There were gas shows in the section which indicate a potential hydrocarbon source. The results of these two wells will be analyzed to determine the future exploration program direction in the North Turkana Basin.

During 2013, the Company and its partners completed a 1,174 kilometer 2D seismic program in the Chew Bahir Basin on the eastern portion of the South Omo Block, which identified a number of prospects and leads. The Company drilled two exploration wells in the Chew Bahir Basin, located to the east of the South Omo Block, in 2014. In May 2014, the Company released the results of the first of these wells, Shimela-1, which reached a final depth of 1,940 meters and encountered water bearing reservoirs. Shimela-1 was drilled to test a prospect in a north-western sub-basin of the vast Chew Bahir basin. The frontier wildcat well encountered lacustrine and volcanic rocks including almost 100 meters of net sandstone reservoir within siltstones and claystones. Trace thermogenic gas shows were recorded at 1,900 metres.

In July 2014, the Company reported that the Gardim-1 exploration well, drilled on the eastern flank of the Chew Bahir Basin in the South Omo license, onshore Ethiopia, has reached a total depth of 2,468 metres in basement, without encountering commercial oil. The well intersected lacustrine and volcanic formations, similar to those found in the Shimela-1 well on the north-western flank of the basin. Minor intervals with thermogenic gas shows were intersected just above basement. The well was plugged and abandoned and drilling operations demobilised whilst drilling results are integrated into the regional basin model.

During 2015 the Company and partners worked to incorporate well results and evaluate remaining potential in the block. Certain well data including rock samples acquired during drilling were processed by various laboratories to determine stratigraphic ages and characteristics of potential source rocks. These are other data and studies are being reviewed to assess remaining prospectivity. The block is in the final exploration period which expires in January 2017, all work commitments have been met or exceeded on the block.

Rift Basin Area

The Company completed the acquisition of a 36,500 line kilometer Full Tensor Gradiometry ("**FTG**") survey in October 2013. In 2013 and 2014 the Company completed five geologic field campaigns and also completed an exhaustive environmental and social impact assessment over the block in preparation for a 2D seismic program that commenced in the first quarter of 2015. The Company completed recording of 604 km of 2D seismic data that included both land and marine seismic acquisition.

During the fourth quarter of 2015 the Company completed processing all newly acquired seismic data and began subsurface mapping. After completing all work commitments for the Initial Term, the Company requested and received a 1-year extension to the Initial Term to allow more time to integrate surface field data with seismic data and to prepare and rank a prospect inventory for prospective exploratory wells. The Company and partners will continue a review of prospects in 2016 in preparation for a recommendation by February 2017 to enter the First Extension Term which includes a commitment to drill an exploratory well.

Item 6.8 Production Estimates

The Company is unable to estimate production or future net revenue from its oil and gas activities as of December 31, 2015.

Item 6.9 Production History

The Company had no oil and gas production history as of December 31, 2015.

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SCHEDULE B

FORM 51-101F3
Report of Management and Directors on Oil and Gas Disclosure

(This is the form referred to in item 3 of section 2.1 of National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Terms to which a meaning is ascribed in NI 51-101 have the same meaning in this form.

Report of Management and Directors on Reserves Data and Other Information

The Reserves Committee of the board of directors of Africa Oil Corp. (the "Company") has reviewed the oil and gas activities of the Company and has determined that the Company had no reserves as of December 31, 2015.

An independent qualified reserves evaluator or qualified reserves auditor has not been retained to evaluate the Company's reserves data. No report of an independent qualified reserves evaluator or qualified reserves auditor will be filed with securities regulatory authorities with respect to the financial year ended on December 31, 2015**.**

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing information detailing the Company's oil and gas activities; and
(b) the content and filing of this report.

/s/Keith Hill
Keith C. Hill, Chief Executive Officer

/s/Ian Gibbs
Ian Gibbs, Chief Financial Officer

/s/Gary S. Guidry
Gary S. Guidry, Director

/s/Andrew Bartlett
Andrew Bartlett, Director

Date: February 26, 2016

SCHEDULE C

AFRICA OIL CORP.
(the "Company")

MANDATE OF THE AUDIT COMMITTEE

1. Purpose of the Audit Committee

The Audit Committee oversees the accounting and financial reporting processes of the Company and its subsidiaries and all audits and external reviews of the financial statements of the Company on behalf of the Board, and has general responsibility for oversight of internal controls, accounting and auditing activities of the Company and its subsidiaries.

2. Members of the Audit Committee

2.1. The Audit Committee shall be appointed annually by the Board and shall be composed of three members, each of whom must be a director of the Company and a majority of whom must be independent.

2.2. At least one Member of the Audit Committee must be "financially literate" as defined under National Instrument 52-110, having sufficient accounting or related financial management expertise to read and understand a set of financial statements, including the related notes, that present a breadth and level of complexity of the accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Company's financial statements.

3. Meeting Requirements

3.1. The Committee will, where possible, meet on a regular basis at least once every quarter, and will hold special meetings as it deems necessary or appropriate in its judgment. Meetings may be held in person or telephonically, and shall be at such times and places as the Committee determines. Without a meeting the Committee may act by unanimous written consent of all members.

3.2. Two members of the Audit Committee shall constitute a quorum.

4. Duties and Responsibilities

4.1. Appointment, Oversight and Compensation of Auditor

4.1.1. The Audit Committee shall recommend to the Board:

a) The auditor (the "Auditor") to be nominated for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Company; and

b) The compensation of the Auditor.

In making such recommendations, the Audit Committee shall evaluate the Auditor's performance and review the Auditor's fees for the preceding year.

4.1.2. The Auditor shall report directly to the Audit Committee.

4.1.3. The Audit Committee shall be directly responsible for overseeing the work of the Auditor, including the resolution of disagreements between management and the Auditor regarding financial reporting.

4.1.4. The Audit Committee shall review information, including written statements from the Auditor, concerning any relationships between the Auditor and the Company or any other relationships that may adversely affect the independence of the Auditor and assess the independence of the Auditor.

4.2. Non-Audit Services

4.2.1. All auditing services and non-audit services provided to the Company or the Company's subsidiaries by the Auditor shall, to the extent and in the manner required by applicable law or regulation, be pre-approved by the Audit Committee. In no circumstances shall the Auditor provide any non-audit services to the Company that are prohibited by applicable law or regulation.

4.3. Review of Financial Statements etc.

4.3.1. The Audit Committee shall review the Company's interim and annual financial statements and Management's Discussion and Analysis ("MD&A"), intended for circulation among shareholders; and shall report on them to the Board.

4.3.2. The Audit Committee shall satisfy itself that the audited financial statements and interim financial statements present fairly the financial position and results of operations in accordance with generally accepted accounting principles and that the auditors have no reservations about such statements.

4.3.3. The Audit Committee shall review changes in the accounting policies of the Company and accounting and financial reporting proposals that are provided by the Auditor that may have a significant impact on the Company's financial reports, and report on them to the Board.

4.4. Review of Public Disclosure of Financial Information

4.4.1. The Audit Committee shall review the Company's annual and interim press releases relating to financial results before the Company publicly discloses this information.

4.4.2. The Audit Committee must be satisfied that adequate procedures are in place for the review of the Company's public disclosure of financial information extracted or derived from the Company's financial statements, other than the public disclosure referred to in subsection 5.4.1, and must periodically assess the adequacy of those procedures.

4.5. Review of Annual Audit

4.5.1. The Audit Committee shall review the nature and scope of the annual audit, and the results of the annual audit examination by the Auditor, including any reports of the Auditor prepared in connection with the annual audit.

4.5.2. The Audit Committee shall satisfy itself that there are no unresolved issues between management and the Auditor that could affect the audited financial statements.

4.5.3. The Audit Committee shall satisfy itself that, where there are unsettled issues that do not affect the audited financial statements (e.g. disagreements regarding correction of internal control weaknesses, or the application of accounting principles to proposed transactions), there is an agreed course of action leading to the resolution of these matters.

4.5.4. The Audit Committee shall satisfy itself that there is generally a good working relationship between management and the Auditor.

4.6. Review of Quarterly Review Engagements

4.6.1. The Audit Committee shall review the nature and scope of any review engagements for interim financial statements, and the results of such review engagements by the Auditor, including any reports of the Auditor prepared in connection with such review engagements.

4.6.2. The Audit Committee shall satisfy itself that there are no unresolved issues between management and the Auditor that could affect any interim financial statements.

4.6.3. The Audit Committee shall satisfy itself that, where there are unsettled issues that do not affect any interim financial statements (e.g. disagreements regarding correction of internal control weaknesses, or the application of accounting principles to proposed transactions), there is an agreed course of action leading to the resolution of these matters.

4.7. Internal Controls

4.7.1. The Audit Committee shall have responsibility for oversight of management reporting and internal control for the Company and its subsidiaries.

4.7.2. The Audit Committee shall satisfy itself that there are adequate procedures for review of interim statements and other financial information prior to distribution to shareholders.

4.8. Complaints and Concerns

4.8.1. The Audit Committee shall establish procedures for:

a) the receipt, retention and treatment of complaints received by the Company regarding accounting, internal accounting controls, or auditing matters; and

b) the confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters.

4.9. Hiring Practices

4.9.1. The Audit Committee shall review and approve the Company’s hiring policies regarding partners, employees and former partners and employees of the present and former Auditors of the Company.

4.10. Other Matters

4.10.1. The Audit Committee shall be responsible for oversight of the effectiveness of management’s interaction with and responsiveness to the Board;

4.10.2. The Audit Committee shall review and monitor all related party transactions which may be entered into by the Company.

4.10.3. The Audit Committee shall approve, or disapprove, material contracts where the Board determines it has a conflict.

4.10.4. The Audit Committee shall satisfy itself that management has put into place procedures that facilitate compliance with the provisions of applicable securities laws and regulations relating to insider trading, continuous disclosure and financial reporting.

4.10.5. The Audit Committee shall periodically review the adequacy of this Charter and recommend any changes to the Board.

4.10.6. The Board may refer to the Audit Committee such matters and questions relating to the financial position of the Company and its affiliates as the Board from time to time may see fit.

5. Rights and Authority of the Audit Committee and the Members Thereof

5.1. The Audit Committee has the authority:

a) To engage independent counsel and other advisors as it determines necessary to carry out its duties;

b) To set and require the Company to pay the compensation for any advisors employed by the Audit Committee; and

c) To communicate directly with the Auditor and, if applicable, the Company's internal auditor.

5.2. The members of the Audit Committee shall have the right, for the purpose of performing their duties, to inspect all the books and records of the Company and its affiliates and to discuss those accounts and records and any matters relating to the financial position of the Company with the officers and Auditor of the Company and its affiliates, and any member of the Audit Committee may require the Auditor to attend any or every meeting of the Audit Committee.

6. Miscellaneous

Nothing contained in this Charter is intended to extend applicable standards of liability under statutory or regulatory requirements for the directors of the Company or members of the Audit Committee. The purposes, responsibilities, duties and authorities outlined in this Charter are meant to serve as guidelines rather than as inflexible rules and the Committee is encouraged to adopt such additional procedures and standards as it deems necessary from time to time to fulfill its responsibilities.