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Canadian Reserves and Resources Reporting for Africa Oil Corp: the Nigerian Assets of Prime Oil and Gas, and other Exploration Prospects

Africa Oil Corp.

26 February 2024

Private and Confidential

RISC Ref: 230048

1. Executive Summary

Africa Oil Corp. ("AOC") requested **RISC (UK) Limited** ("RISC") to report on (a) the interests it holds in the Reserves and Contingent Resources of Prime Oil & Gas Coöperatief U.A. ("Prime") and (b) the Prospective Resources it holds in South Africa, as part of its financial reporting to the Toronto Stock Exchange (TSX) in Q1 2024.

RISC reviewed the Reserves and Contingent Resources of Prime at year-end 2023 and has permission from Prime to use this technical work as the basis for reporting in the NI 51-101 F1 and F2 forms. Due to different levels of technical maturity of assets in the portfolio, some assets underwent an audit, whilst others were evaluated in detail. The interests include world-class deep-water blocks in Nigeria: OML 127; Petroleum Mining Leases PML 2, PML 3 and PML 4 and Petroleum Prospecting License PPL 261 (formerly OML 130). The portfolio includes three producing fields (Agbami, Akpo and Egina), one field development with FID[1] expected in Q4 2024 (Preowei), and two undeveloped oil discoveries (Ikija and Egina South).

In addition to Reserves and Contingent Resources of Prime, RISC has also audited the Prospective Resources where AOC also holds a direct interest in Block 3B/4B in the Orange Basin, offshore Republic of South Africa.

RISC has completed the following two forms:

- NI 51-101 F1
- NI 51-101 F2

Upon request, RISC can also complete a questionnaire from AOC's financial auditor and can be available for a call to discuss this further.

[1] Financial Investment Decision

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2. Form NI 51-101 F1

PART 1 DATE OF STATEMENT

Item 1.1 Relevant Dates

This Statement of Reserves Data and Other Oil and Gas Information (the "Statement") of Africa Oil Corporation ("AOC" or the "Corporation") is dated 26 February 2024. The preparation date of this document is 26 February 2024 and the effective date of the information provided in this Statement is 31 December 2023.

PART 2 DISCLOSURE OF RESERVES DATA

RISC (UK) Limited ("RISC") prepared a report dated 14 February 2023 (the "RISC report"), in which it evaluated at year-end 2023, the oil and natural gas Reserves and Contingent Resources attributable to Prime Oil & Gas Coöperatief U.A. ("Prime"). Africa Oil Corp ("AOC") holds a 50% shareholding interest in Prime. For the purposes of this Statement, the disclosed Reserves, Resources and other information pertain to 50% of Prime's interests in offshore Nigeria: Oil Mining Lease ("OML") 127; Petroleum Mining Leases ("PML") 2, PML 3 and PML 4; and Petroleum Prospecting License (PPL) 261.

Prime holds an 8% Working Interest in OML 127 and a 16% Working Interest in PML 2, PML 3, PML 4 and PPL 261.

OML 127 contains part of the producing Agbami field. Agbami has been unitised over OML 127 and OML 128 approximately 62.5% and 37.5% respectively. PML 2 contains the producing Akpo field. PML 3 contains the producing Egina field. PML 4 contains the planned Preowei development. PPL 261 contains the Egina South discovery.

We note that PML 2, PML 3, PML 4 and PPL 261 cover the area formerly known as OML 130. The change of names in 2023 related to the licence renewal under the Petroleum Industry Act (PIA).

The contents of the RISC report and RISC's estimates of Reserves are based on data provided to RISC by AOC or released to RISC by Prime. RISC has accepted, without independent verification, the accuracy and completeness of these data. All information provided to RISC was as at year-end 2023 and, accordingly, some of this information may not be representative of current conditions.

Standard geological and engineering techniques accepted by the petroleum industry were used in estimating Resources. These techniques rely on engineering and geo-scientific interpretation and judgement; hence the Resources included in this Statement are estimates only and should not be construed to be exact quantities. It should be recognised that such estimates of Reserves may increase or decrease in future if there are changes to the technical interpretation, economic criteria or regulatory requirements. In assessing Undeveloped Reserves, RISC makes judgements related to the success of future operations and delivery of projects in accordance with the operator's current plans and RISC's opinion of likely plans. The classification of Undeveloped Reserves further relies upon RISC's opinion of the firm intent of the joint venture partnership to proceed with projects. It is possible that plans may change in the future.

RISC estimated the Net Present Value (NPV) of future revenue of Prime's properties before and after taxes, at various discount rates. Assumptions and qualifications relating to costs, prices for future production and other matters are summarized in the notes to the tables. It should not be assumed that the estimated future net revenue represents the fair market value of the Reserves. There is no assurance that the escalating price and cost assumptions will be realised. The Reserves and revenue estimates set forth in this report are estimates only and the actual Reserves and revenue may be greater or less than those calculated.

All currency amounts in this Statement are United States dollars (“USD”, “$”) unless otherwise indicated.

The operators of the Agbami, Akpo and Egina fields are also evaluating options to drill additional infill wells on these fields, blow down a gas reservoir, develop additional horizons and develop undeveloped discoveries. These are classified as Contingent Resources. All of the Contingent Resources are included in the Appendix to this statement.

In addition to the reserves and resources in the Nigerian assets, AOC has interests in exploration assets in South Africa (Block 3B/4B) and in Equatorial Guinea (Blocks EG-31 & EG-18). RISC prepared a Prospective Resources report dated 7 March 2023 (the “RISC Orange Basin CPR”), in which it reported an independent audit of Block 3B/4B. The Prospective Resource Volumes (including risked volumes) for AOC’s exploration portfolio reported in the Appendix relates to those same assets and evaluations.

Item 2.1 Reserves Data (Forecast Prices and Costs)

The following table discloses, in the aggregate, AOC’s gross and net proved, probable and possible Reserves, estimated using forecast prices and costs, by product type, assessed at 31 December 2023. “Forecast prices and costs” means future prices and costs used by RISC in the RISC Report. The fields are produced under Production Sharing Agreements (PSAs) and Production Sharing Contracts (PSCs). The Gross Reserves are calculated as the total project sales volumes multiplied by the working interests in the PSAs. The Net Oil Reserves are calculated using the economic interest booking methodology and include cost recovery oil, tax oil and profit oil as set out in the terms of the Production Sharing Agreements. The disclosed volumes relate to 50% of Prime’s interests, as AOC holds a 50% shareholding interest in Prime.

Summary of Oil and Gas Reserves (Forecast Prices and Costs)						
	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
Reserve Category	**Gross (MMstb)**	**Net (MMstb)**	**Gross (Bscf)**	**Net (Bscf)**	**Gross (MMstb)**	**Net (MMstb)**
Proved						
Developed Producing	15.6	19.9	9.2	9.2	-	-
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	10.0	11.5	15.6	15.6	-	-
Total Proved	**25.7**	**31.4**	**24.9**	**24.9**	**-**	**-**
Probable	18.0	19.6	26.4	26.4	-	-
Total Proved plus Probable	**43.6**	**51.0**	**51.3**	**51.3**	**-**	**-**
Possible	16.0	16.2	32.3	32.3	-	-
Total proved plus probable plus possible	**59.6**	**67.2**	**83.6**	**83.6**	**-**	**-**

Notes:

1. Figures in table may not add precisely due to rounding.
2. Units are MMstb (million stock tank barrels) and Bscf (billion standard cubic feet).
3. Gross Company Reserves are the total project sales volumes multiplied by 50% of Prime's working interest.
4. Net oil Reserves are AOC's share of Prime's net entitlement calculated using economic limit testing.
5. Gross and net Reserves for sales gas are equal as the gas terms are set out in the Gas Sales and Purchase Agreement, rather than the PSA, and the net Reserves are based on AOC's working interest.

The following table discloses, in aggregate, the Net Present Value of the future net revenue attributable to the Reserves categories in the preceding table. These have been estimated using forecast prices and costs, before and after deducting future income tax expenses, and calculated at discount rates of 0 percent, 5 percent, 10 percent, 15 percent and 20 percent.

Summary of Net Present Values of Future Net Revenue Forecast Prices and Costs ($ million)											
	Before Income Taxes Discounted at (%/Year)					After Income Taxes Discounted at (%/Year)					Before Tax Net Val
Reserve Category	**0**	**5**	**10**	**15**	**20**	**0**	**5**	**10**	**15**	**20**	**10%/yr ($/BOE)**
Proved											
Developed Producing	968	813	714	644	592	720	595	518	466	427	33.3
Developed Non-Producing	-	-	-	-	-	-	-	-	-	-	-
Undeveloped	570	412	306	232	180	401	283	204	150	111	21.8
Total Proved	**1,538**	**1,225**	**1,020**	**877**	**771**	**1,121**	**878**	**722**	**615**	**538**	**28.7**
Probable	1,333	934	694	539	435	902	632	470	365	294	29.0
Total Proved plus Probable	**2,871**	**2,160**	**1,714**	**1,416**	**1,206**	**2,023**	**1,510**	**1,192**	**980**	**832**	**28.8**
Possible	1,427	963	694	528	418	978	659	477	364	289	32.1
Total Proved plus Probable plus Possible	**4,298**	**3,122**	**2,408**	**1,944**	**1,624**	**3,002**	**2,169**	**1,668**	**1,344**	**1,121**	**29.7**

Notes:

1. Figures in table may not add precisely due to rounding.
2. Units are US$ million.
3. Unit values are based on net reserve volumes Barrel of Oil Equivalent (BOE): 6 Mcf = 1 BOE. BOEs may be misleading particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

The following table discloses, in the aggregate, certain elements of the future net revenue attributable to the total Proved Reserves, the total Proved plus Possible Reserves, and the Proved plus Probable plus Possible Reserves, estimated using forecast prices and costs, and calculated without discount.

Total Future Net Revenue (Undiscounted) Forecast Prices and Costs (US$ millions)								
Reserves Category	**Revenue**	**Royalties**	**Operating Costs**	**Development Costs**	**Abandonment / Reclamation Costs**	**Future Net Revenue Before Income Taxes**	**Income Taxes**	**Future Net Revenue After Income Taxes**
Proved	2,873	129	602	448	156	1,538	416	1,121
Proved plus Probable	5,010	254	1,176	525	183	2,871	848	2,023
Proved plus Probable plus Possible	6,694	367	1,300	531	198	4,298	1,296	3,002
Notes: 1. Units are US$ million.								

The following table discloses, by production group, the net present value of the future net revenue attributable to the Proved Reserves, Proved plus Probable Reserves, and Proved plus Probable plus Possible Reserves before deducting future income tax expenses, estimated using forecast prices and costs, and calculated using a 10 percent discount rate.

Net Present Value of Future Net Revenue by Production Group Forecast Prices and Costs			
Reserves Category	**Production Group**	**Future Net Revenue Before Income Taxes (Discounted at 10%/Year) ($ million)**	**Unit Value Before Income Taxes (Discounted at 10%/Year) ($/BOE)**
Proved	Light and Medium Crude Oil (including solution gas and associated by-products)	1,020	28.7
Proved plus Probable	Light and Medium Crude Oil (including solution gas and associated by-products)	1,714	28.8
Proved plus Probable plus Possible	Light and Medium Crude Oil (including solution gas and associated by-products)	2,408	29.7

Notes:

1. Units are US$ million.
2. Unit values are based on net reserve volumes Barrel of Oil Equivalent (BOE): 6 Mcf = 1 BOE. BOEs may be misleading particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

A Summary of Contingent Resources and Prospective Resources as of 31 December 2023 has been included in the Appendix at the end of this document.

PART 3 PRICING ASSUMPTIONS

Item 3.1 Constant Prices Used in Supplementary Estimates

Not relevant.

Item 3.2 Forecast Prices Used in Estimates

RISC's price forecast used in preparing the Reserves data are provided in the table below, at the effective date of this statement (31 December 2023). Oil prices are based on the average Brent forward curve over the 60 day period between 27 September 2023 and 25 November 2023 for 2024 and 2025, followed by a flat real price of $75/bbl from 2026 onwards. Gas prices are based on the gas sales and purchase agreement, calculated by applying a monthly Brent adjustment and subtracting a handling fee.

	Summary of Pricing and Inflation Rate Assumptions Forecast Prices & Costs		
Year	**Brent Oil Price US$/bbl**	**Gas Price US$/MMBTU**	**Inflation Rate (%/year)**
2023 achieved sales price	81.1	0.7	-
2024	82.0	1.1	-
2025	78.0	1.0	2.5%
2026	78.8	1.1	2.5%
2027	80.8	1.1	2.5%
2028	82.8	1.1	2.5%
2029 and beyond	Escalation Rate of 2.5%	Escalation Rate of 2.5%	Escalation Rate of 2.5%

Notes:

1. Average oil prices received in 2023 include hedging.
2. Forecast prices include no hedging.
3. This summary table identifies benchmark reference pricing schedules used.
4. Inflation rates are used for forecasting prices and costs.
5. Gas price units are in US$ per million BTU (British Thermal Units).

PART 4 RECONCILIATION OF CHANGES IN RESERVES

Item 4.1 Reserves Reconciliation

The following table provides a reconciliation between gross Reserves disclosed on the 27 February 2023 (effective date 31 December, 2022) and this disclosure (effective date 31 December, 2023).

Gross	Light and Medium Oil (MMstb)			Conventional Natural Gas (Bscf)		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Effective date 31 December 2022	29.1	18.3	47.4	32.9	16.5	49.4
Extensions and Improved Recovery	0.0	0.0	0.0	0.0	0.0	0.0
Resource Transfers	0.0	0.0	0.0	0.0	0.0	0.0
Technical Revisions	1.9	-0.2	1.8	1.4	10.1	11.5
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	0.0	0.0	0.0	0.0	0.0	0.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	0.2	-0.2	0.1	0.1	-0.1	0.0
Production	5.6	0.0	5.6	9.5	0.0	9.5
Effective date 31 December 2023	**25.7**	**18.0**	**43.6**	**24.9**	**26.4**	**51.3**

Notes:

1. Figures in table may not add precisely due to rounding.
2. Gross Company Reserves are the total project sales volumes multiplied by AOC's share of Prime's working interest.
3. RISC notes that the Proved + Probable Reserves reconciliation for oil and gas is lower than the Proved in some categories. This results in a negative Probable increment. The difference is due to a larger increase in Proved Reserves than the Proved + Probable, compared to last year. The reasons are explained in the text below.

Technical revisions in oil Reserves are mostly:

- Egina field – significant changes to performance were observed in the R1180 reservoirs in 2023 together with an increase in total field GOR.
- Akpo field – gas blowdown of Akpo D reservoir is now included in the Developed forecasts as reserves (migrated from Contingent Resources).
- Agbami field – reserves in the Agbami field have increased at the 1P and 2P level mainly reflecting increasing confidence in the developed reserves.

The economic factor impacting Reserves relates to the change in oil price forecast since 31 December 2022.

PART 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Item 5.1 Undeveloped Reserves

Reserves were first attributed to AOC in March 2020, after the acquisition of 50% of Prime was completed.

The Proved and the Probable Undeveloped Reserves are associated with the continuation of long-term drilling and development programmes committed to under the approved field development plans. The fields are large offshore developments where drilling/production have been ongoing for several years and the attribution of Undeveloped Reserves is based on a continuation of, and the completion of, the approved Field Development Plans. For the Undeveloped Reserves: six further wells plus a subsea workover are planned for the Agbami field in 2026/7; 3 wells are planned in the Akpo West field between 2023 and 2024; 2 additional wells are planned on the Akpo field in 2024; and 6 further wells and a sidetrack are planned on the Egina field between 2024 and 2025. In attributing Proved and Probable Undeveloped Reserves to each field, the remaining wells on each field are considered as a project, not as individual wells.

The Undeveloped Reserves also include the Preowei field development. The FDP for this field has been approved by the Nigerian authorities and first oil is planned for Q3 2027. This timeline for Reserves extends beyond two years as Preowei is a complex, deepwater field that requires significant capital, with a long development period. The FEED[2] study is currently underway. Financial Investment Decision (FID) is now expected in Q4 2024 by the Operator. Drilling is planned to commence in Q1 2027 leading to first oil in Q3 2027.

Since the previous National Instrument filing, three wells have been drilled in Egina. Incremental production volumes of these wells are included with Developed reserves.

In general, the operating partnerships have a good track record of delivering on their development plans. Factors that might contribute to delays or cancellations of the planned development include:

- Industry-wide delays in procurement, approvals, etc. related to ongoing supply chain issues;
- Changing technical conditions such as production anomalies;
- Optimizing facilities throughput and utilization;
- Changing economic conditions (due to pricing, operating or capital expenditure fluctuations and restricted debt or capital markets); and
- Changes in regulations or fiscal terms.

[2] Front End Engineering and Design

The table below shows the Undeveloped Reserves that were first attributed in each of the most recent three financial years. No undeveloped reserve projects were added in 2023.

Summary of Company Undeveloped Reserves (Forecast Prices & Costs)			
Year First Attributed	Light/Medium Oil (MMstb)	Heavy Oil (MMstb)	Conventional Natural Gas (Bscf)
Proved Undeveloped			
2020	3.9	-	4.2
2021	0.7	-	0.3
2022	0.4	-	0.0
2023	0.0	-	0.0
Probable Undeveloped			
2020	2.6	-	7.1
2021	1.0	-	0.4
2022	0.2	-	0.0
2023	0.0	-	0.0

Notes:

1. Undeveloped Reserves were first attributed in March 2020 when the assets were acquired by AOC.
2. Net oil Reserves are AOC’s share of Prime’s net entitlement calculated using the economic limit testing.

Item 5.2 Significant Factors or Uncertainties Affecting Reserves Data

The Nigerian Petroleum Industry Act (PIA) was passed into law in August 2021. This introduced a new licensing and fiscal regime for upstream operations. The old OML 130 (now PML 2, PML 3, PML 4 & PPL 261) and OML 127 converted to the PIA terms in June and March 2023, respectively. As part of the conversion process license extensions of 20 years were also granted in both licenses. RISC’s calculations of Reserves and NPVs incorporate the new fiscal regime.

The Agbami field straddles OML 127 and OML 128. The Equity Determination in 2010 apportioned resources between block OML 127 and OML 128 approximately 62.5% and 37.5% respectively. The 2012 Final Redetermination was referred to an Expert who determined an OML 127 equity of 72.064%. This final equity revision is still pending implementation, so RISC has retained the 2010 determination. If this is implemented, the Agbami equity share (and net Reserves) of AOC will increase.

The fields have been developed using floating production vessels. Abandonment and reclamation costs will therefore entail well abandonment and removal of sub-sea infrastructure. These costs have been fully accounted for in the economic analysis of the Reserves cases and are estimated by RISC (Gross 100%) at:

- Agbami US$623 million;
- Akpo US$800 million;
- Egina US$768 million;
- Preowei US$140 million.

There are no specific technical uncertainties identified for these assets. However, it is noted that these fields are geologically complex and even with modern seismic techniques, uncertainty remains regarding reservoir extent, connectivity, and the timing of water and gas breakthrough at the wells.

The reader is also directed to the 'Risk Factors' section of the AOC financial statements for year-end 2023.

Item 5.3 Future Development Costs

The following table provides information regarding the development costs deducted in the estimation of future net revenue attributable to the Reserves.

Future Development Costs (Forecast Prices & Costs) ($ million)		
Year	**Proved Reserves**	**Proved plus Probable Reserves**
2024	94	94
2025	65	65
2026	83	83
2027	96	96
2028	47	47
Subtotal	**387**	**387**
Remainder (to end of Field Life)	61	138
Total (Undiscounted)	**448**	**525**
Total (Discounted at 10%/year)	339	355

Notes:

1. Figures in table may not add precisely due to rounding.
2. The Future Development Costs shown are associated with booked Reserves in the RISC report and do not necessarily represent the full exploration and development plans.
3. Gross costs are based on the total project costs multiplied by AOC's paying interest.

The sources of funding for future costs of new wells and new developments include a combination of cashflow from operations and existing debt facilities.

PART 6 OTHER OIL AND GAS INFORMATION

Item 6.1 Oil and Gas Properties and Wells

The properties are located offshore Nigeria comprising an interest in OML 127 (which contains the producing Agbami field) and an interest in PML 2, PML 3, PML 4 & PPL 261, collectively formerly known as OML 130 (which contains the producing Akpo and the Egina fields and the planned Preowei development).

OML 127 - Location and Partner Equities

The Agbami oil field is located in OML 127, offshore Nigeria, in water depths between 1,280 m and 1,650 m. It is 110 km south-southwest from the nearest Nigerian shoreline and approximately 350 km southeast of Lagos.

The Agbami field straddles licences OML 127 and OML 128. The Equity Determination in 2010 apportioned resources between block OML 127 and OML 128 with 62.4619% and 37.5381% respectively. Star Deep Water Petroleum Nigeria, a wholly owned subsidiary of Chevron Corporation, operates the Agbami field under a production sharing agreement (the "Agbami PSA"). Ownerships within OML 127 at the effective date were Prime (8%), Star Deep Water Petroleum Limited (32%) and Famfa Oil Limited (60%). In 2020, AOC acquired a 50% shareholder interest in Prime. The resulting effective interest of AOC in the Agbami field is 2.498%.

The PIA was passed into law on 16 of August 2021 and introduced several changes to the petroleum industry in Nigeria. OML 127 converted to the PIA in March 2023.

OML 127 - Agbami Field

The field was discovered by well Agbami-1 in 1998 and the extension into the adjacent licence was proved by the Ekoli-1 well in 2000. The oil is light with a gravity of 45° to 47° API. The field is developed via sub-sea wells tied back to a dedicated Floating Production Storage and Offtake (FPSO) vessel through steel catenary risers. Production commenced in June 2008 and peak production of 250,000 bopd (gross) was attained in 2009. At 31 December 2023, 30 producers, 5 gas injectors and 10 water injectors had been drilled. Field average oil production rate in 2023 was about 98,000 bopd. Cumulative oil production to 31 December 2023 was 1089 MMstb for the field. There is no gas export, so all gas is re-injected, flared or used as fuel.

Reserves include 6 infill wells planned for 2026/7. Contingent Resources include 6 further infill wells and the tie back of the Ikija discovery.

PML 2, PML 3, PML 4 and PPL 261 - Location and Partner Equities

The areas of OML 130 are now licenced under the titles PML 2 (for Akpo), PML 3 (for Egina), PML 4 (for Preowei) and PPL 261 (for Egina South). The change of names was in 2023, related to the licence renewal under the Petroleum Industry Act (PIA).

The title interests of PML 2, PML 3, PML 4 and PPL 261 are held under two distinct but inter-linked, contractual structures that were set up when the licence was known as OML 130. A 50% interest is held by the Nigerian National Petroleum Corporation under a production sharing agreement (the "130 PSA") with South Atlantic Petroleum Limited ("SAPETRO") as the Contractor. SAPETRO subsequently assigned a 90% share of its interest as Contractor under the 130 PSA to CNOOC Exploration and Production Limited ("CNOOC"). The other 50% interest is held under an agreement, which was amended and re-named the production sharing agreement entered into by Total Upstream Nigeria Limited ("TUPNI") 48%; Prime 32% and SAPETRO 20%. The resulting interests were therefore TUPNI (24%), CNOOC (45%), Prime (16%) and SAPETRO (15%). In 2020, AOC acquired a 50% shareholder interest in Prime. The resulting equity interest held by AOC in the fields in the licence formerly known as OML 130 is 8%.

PML 2 – Akpo Field

The Akpo field is located offshore Nigeria in PML 2, approximately 200 km from Port Harcourt, in water depths between 1,100 m and 1,300 m. The field is operated by TotalEnergies. Akpo was discovered by well Akpo-1 in 2000 and was appraised from 2000 to 2002. Akpo contains a critical fluid that can also be described as condensate, or light oil with an original Gas Oil Ratio (GOR) of approximately 3,500 scf/bbl. There is a significant variation of fluid properties with depth, without sharp gas-oil contacts. Commerciality was declared in 2005 and the field has been developed via sub-sea wells with four production flowline loops tied back to a FPSO through steel catenary risers. Production commenced in March 2009 and plateau oil production of approximately 180,000 bopd (gross) was attained in 2010. Pressure maintenance at or near initial pressures is required and is provided by both water injection and gas injection. Part of the produced gas is re-injected for pressure maintenance and the remaining part is transported via an export line to the Nigeria LNG plant (NLNG) via the Amenam field. At 31 December 2023, there were 51 wells connected with 29 producers, 20 water injectors and 2 gas injectors. Two oil production wells and one gas injection well were to be drilled in the Akpo West field over 2023 and 2024. Drilling was ongoing at the end of December 2023. An additional infill production well DP-5 is planned to be drilled in Q1 2024 (for the Akpo D reservoir gas blowdown), followed by the B-W4 water injection well in Q4 2024. Further opportunities are being evaluated and have been included as Contingent Resources including 5 additional infill wells and miscible gas injection. At the end of 2023, the field was producing approximately 63,000 stb/d at 65% water-cut. The cumulative oil production to 31 December 2023 was 664 MMstb. Cumulative gas production to 31 December 2023 was 2.6 Tscf, cumulative injection 0.9 Tscf and cumulative gas export was 1.5 Tscf.

PML 3 – Egina Field

The Egina oil field is located offshore Nigeria in PML 3, approximately 200 km from Port Harcourt and 20 km southwest of the Akpo field, in water depths between 1,150 m and 1,750 m. The field was discovered by well Egina-1 in 2003 which tested the southern compartment of Egina Main. The field was subsequently appraised during 2004 to 2006. The oil is 25° to 41° API gravity. The field is currently under development via sub-sea well loops tied back to a FPSO. The project was sanctioned in May 2013 and first oil was achieved on 29 December 2018. In 2019, the field ramped up to its plateau production rate of 208,000 bopd, with gas exports of 130 MMscf/d. The initial development drilling campaign on Egina started in December 2014 and was completed in 2019. At December 2023 there were 17 production wells and 16 water injector wells, with a further 6 wells and a sidetrack considered as firm on the drilling sequence (2024-2025). At end December 2023, Egina was producing approximately 93,000 stb/d and 140 MMscf with 51% water-cut. Egina has achieved a cumulative production of 256 MMstb and 198 Bscf to 31 December 2023.

PML 4 – Preowei Field

Preowei is an undeveloped oil and gas discovery in PML 4, in water depths ranging between 1,100 m and 1,300 m. The field is 20 km northwest of Akpo and 29 km north of Egina. Preowei was discovered in 2003 by the Preowei-1B well. An appraisal well, Preowei-2, was drilled in 2005 and a further appraisal well, Preowei-3, was drilled in 2017. The field is operated by TotalEnergies. The FDP was approved by the Nigerian Authorities in Q2 2019. The FDP includes 9 producing wells and 9 water injectors, however following an optimisation study the operator plans to drill 8 production wells and 8 injectors. A further 8 contingent wells (4 producers and 4 water injectors) may be drilled. The subsea wells will be tied back to the Egina FPSO for oil and gas export.

Following tie-back, surplus gas will be exported via the Egina-Akpo gas line to the Bonny LNG plant, with commercial terms agreed under the Gas Sale and Purchase Agreement as for Egina. Plateau production of 65,000 bopd is expected and start-up is scheduled for 2027, with additional Contingent Resources to start up in 2029.

The following table sets forth the number and status of wells as at the effective date. All the completed production wells are included under producing.

Oil and Gas Wells				
	Producing		Non-Producing	
Wells	**Gross**	**Net**	**Gross**	**Net**
Nigeria OML 127 and PML 2, PML 3, PML 4, PPL 261				
Oil	76	4.4	0	0.0
Gas	0	0.0	0	0.0
Total	76	4.4	0	0.0

Notes:

1. Gross is the total number of oil and gas production wells on the properties.
2. Net is the sum of AOC's working interest in the gross wells.
3. Non-producing wells do not include other types of wells such as service wells.

In addition to the properties above, AOC has interests in Prospective Resources. These are detailed in the Appendix to this document.

Item 6.2 Properties with No Attributed Reserves

As of 31 December 2023, AOC had properties in addition to those in the Prime portfolio. No reserves or Contingent Resources have been attributed to these properties but they contain Prospective Resources. The properties with no attributed reserves are summarized in the table below:

AOC Properties with No Attributed Reserves[1]						
Country	**Block**	**Net Working Interest(1)**	**Gross Area (km^2)**	**Net Area(2) (km^2)**	**Commitments**	**Expiry Date**
South Africa	3B/4B	26.25%(3) (Operator)	17,581	4,615(4)	Minimum commitment: Reprocess and interpret existing 3D seismic, update prospect inventory, conduct commercial evaluations of prospects	26 October 2024(5,6)
Equatorial Guinea	EG-31	80% (Operator)	1084	867	The First Exploration Sub-Period (2 years) has a minimum spend of US$3 million focussed on 3D seismic data reprocessing.	30 April 2027
Equatorial Guinea	EG-18	80% (Operator)	1660	1,328	The First Exploration Sub-Period has a minimum spend US$4 million focused on 3D seismic data reprocessing.	30 April 2027

Notes:

1. Net Working Interests are subject to back-in rights, if any exist, of respective governments.
2. Net acreage is calculated by multiplying Gross Acreage by the current Net Working Interest.
3. AOC purchased additional interests in the block and currently owns a 26.25% interest. This transaction was approved by government on 22 Jan 2024.
4. The 20% relinquishment requirement was deferred by government approval at the time of the renewal until disclosure of potential marine protected areas is determined.
5. The application to extend the Block 3B/4B license and to move into the first extension period of 2 years was approved on 27 October 2022.
6. RISC prepared a Prospective Resources report dated 7 March 2023 (the “RISC Orange Basin CPR”), in which it reported an independent qualified evaluation of Block 3B/4B, South Africa.

On May 23, 2023, the Company submitted withdrawal notices to its JV Parties on Blocks 10BB, 13T and 10BA in Kenya, to unconditionally and irrevocably withdraw from the entirety of the joint operation agreements and PSCs for these Concessions. The Company is waiting for the Kenyan government consent to the withdrawal and the transfer of rights.

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

Please see the Company's financial statements, meeting materials and corporate filings for the year ended 31 December 2023 for details pertaining to economic factors and uncertainties relating to properties with no attributed reserves.

Also see the Appendix in this document related to Prospective Resources.

Item 6.3 Forward Contracts

Prime has a gas sales and purchase agreement in place for the fields in PML 2, PML 3, PML 4 and PPL 261 (formerly OML 130) that share the same gas export system. The gas buyer consortium Nigerian National Petroleum Corporation ("NNPC")/Total E&P Nigeria Limited ("TEPNL") was responsible for construction and operation of the gas export system to the onshore Bonny LNG plant in return for receiving 1 Tscf of sales gas at zero cost. This hurdle was achieved in July 2018. The parties agreed to a new gas sale and purchase agreement (the "GSPA") in July 2018, which has been signed by all OML 130 PSA parties and is currently with NNPC pending its signature. Gas is now being sold under the new GSPA to the NNPC/TEPNL JV which continues to sell the gas to Nigeria LNG. The OML 130 Partners (SAEPETRO, TUPNI and Prime) have been invoicing the gas buyer. The maximum design capacity of the gas export facilities is 400 MMscf/d.

Prime historically fixed the Dated Brent component of the sales price in its forward sales contracts ahead of the lifting date, based on the forward curve price for the expected lifting date. During Q2 2022, Prime's Supervisory Board approved a revised crude marketing strategy that maintains the 50% - 70% coverage target for the next 12-months' scheduled cargoes but no longer fixes the Dated Brent component for all of the sales ahead of the lifting date, instead uses a trigger price mechanism. Under this new strategy, Prime gives an irrevocable instruction to an offtaker to fix the Dated Brent component of a cargo when the forward curve price goes below a certain trigger based on a percentage of the Brent forward curve (at the time when the instruction was given) for the month of the expected lifting. Otherwise, the cargo is sold on a spot basis. The current percentage used by Prime to set these thresholds is around 80% of the Brent forward curve and it can be altered depending on, among other factors, the shape of the forward curve.

For further details on Prime's hedging policy, please see the Company's financial statements, meeting materials and corporate filings for the year ended 31 December 2023.

Item 6.5 Tax Horizon

The Corporation is not required to pay income taxes for its most recently completed financial year. For a discussion of AOC's tax status, please see the Company's financial statements, meeting materials and corporate filings for the year ended 31 December 2023.

Item 6.6 Costs Incurred

The costs included in the following represent AOC's share of the total costs incurred for the assets.

Costs incurred in the year ended 31 December 2023				
US$ millions	**Acquisition Costs**	**Exploration Costs**	**Development Costs**	**Other Costs**
Nigeria	0	7	68	67
South Africa	2.5[3]	0.7	0	0
Equatorial Guinea	7.8 [4]	4.8	0	0.8

Notes:

1. Costs are based on the total project costs multiplied by AOC's paying interest.
2. Exploration costs relate to seismic purchase & acquisition, processing and studies. No exploration wells were drilled.
3. Africa Oil paid an initial $2.5 million in the year ending 31 December 2023 to acquire an additional 6.25% of Block 3B/4B and a further $2.5 million on receiving government approval of the transfer on 22 January 2024.
4. Equatorial Guinea acquisition costs include the cost of purchasing existing well and seismic data, and signing bonuses related to blocks EG-18 and EG-31.

Item 6.7 Exploration and Development Activities

One oil production well was drilled in both Egina and Akpo West, while two water injection service wells were drilled in Egina in 2023. No other wells were drilled in OML 127 or PML 2, PML 3 & PML 4.

Wells drilled and completed in the year ended 31 December 2023						
	Exploration Wells	**Stratigraphic Test Wells**	**Oil Wells**	**Gas Wells**	**Service Wells**	**Dry Holes**
Gross	0	0	2	0	2	0
Net	0.0	0.0	0.3	0.0	0.3	0.0

Notes:

1. Gross is the total number of wells drilled and completed on the properties.
2. Net is the sum of AOC's working interest in the gross wells.

AOC's most important current and likely development activities in Nigeria will be the completion of the planned drilling activities on the producing fields and the Preowei development as described above under Undeveloped Reserves.

The operators are also evaluating options to drill additional infill wells on these fields, commence miscible gas injection, and appraise/develop undeveloped discoveries. These are classified as Contingent Resources and are included in the Appendix to this statement.

No exploration wells were drilled in 2023. Exploration activities for the Equatorial Guinea assets include the purchase of well data, seismic data for reprocessing and interpretation, followed by desktop technical studies. Exploration activities related to the South Africa assets includes subsurface studies and preparation of environmental impact assessments by external technical consultancies.

Future exploration activities include further technical studies, seismic processing, and potentially drilling exploration wells.

Item 6.8 Production Estimates

The following table sets out the estimated volumes of production for 2024 from OML 127 and PML 2, PML 3 & PML 4, which reflects the estimates of gross proved Reserves and gross probable Reserves disclosed under Item 2.1 of this Statement.

Summary of Production Estimates by Production Group and Reserve Category (Forecast Prices & Costs)			
Nigeria	**Light and Medium Oil**	**Natural Gas**	**Natural Gas Liquids**
Reserves Category	**Gross (MMstb)**	**Gross (Bscf)**	**Gross (MMstb)**
Proved			
Agbami	0.7	-	-
Akpo	1.4	2.8	-
Egina	2.1	1.9	-
Total Proved	**4.3**	**4.7**	**-**
Proved plus Probable			
Agbami	0.9	-	-
Akpo	1.7	4.8	-
Egina	2.2	2.2	-
Total Proved plus Probable	**4.8**	**7.1**	**-**

Notes:

1. Figures in table may not add precisely due to rounding.
2. Gross Company production is the total sales volumes multiplied by AOC’s share of Prime’s working interest.

Item 6.9 Production History

The production volumes, average realised price, royalties, and costs for each quarter of the 2023 financial year are provided in the table below.

Production History for 2023							
	AOC share of gross average gross daily production volume			Average realised price, royalties, gross costs and netback			
	Oil (MMstb)	**Sales Gas (Bscf)**	**Total (MMboe)**	**Average Price Received ($/boe)**	**Royalties Paid ($/boe)**	**Gross Production Costs ($/boe)**	**Netback ($/boe)**
2023 Q1	1.5	2.3	1.9	33.2	3.7	8.8	20.7
2023 Q2	1.4	2.3	1.8	34.1	6.5	7.5	20.1
2023 Q3	1.4	2.5	1.9	32.7	3.9	10.2	18.7
2023 Q4	1.3	2.4	1.7	38.6	3.1	10.5	24.9

Notes:

1. Average prices received in 2023 include hedging.
2. Netback is calculated by subtracting the royalties paid and production costs from the revenue received.
3. Gross Company production is the total sales volumes multiplied by AOC's share of Prime's working interest.
4. Gross costs are based on the total costs multiplied by AOC's share of Prime's paying interest.
5. Unit values are based on net reserve volumes Barrel of Oil Equivalent (BOE): 6 Mcf = 1 BOE. BOEs may be misleading particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

The total production volumes for 2023 for each major field are provided in the table below.

Production History for 2023		
AOC Production Volumes	Oil (MMstb)	Sales Gas (Bscf)
Agbami	0.9	-
Akpo	2.0	6.9
Egina	2.7	2.7
Total	**5.6**	**9.5**

Notes:

1. Figures in table may not add precisely due to rounding.
2. Gross Company production is the sales volume multiplied by AOC's share of Prime's working interest.

3. Appendix to Form NI 51-101 F1: Contingent Resources and Prospective Resources

PART 7 DISCLOSURE OF CONTINGENT RESOURCES DATA AND PROSPECTIVE RESOURCES DATA

Item 7.1 Contingent Resources Data

RISC has prepared an assessment of the crude oil and conventional natural gas Contingent Resources as of 31 December 2023 for AOC. Due to different levels of technical maturity of assets in the portfolio, some assets underwent an audit, whilst others were evaluated in detail. These Contingent Resources are all in the offshore Nigerian licences (OML 127 and PML 2, PML 3, PML 4 & PPL 261) associated with the Reserves in Item 2.1 of main F1 form. The operatorship and net interests in each field are consistent with the Reserves statements.

The Agbami Gas Project has been removed from the portfolio of Contingent Resources.

The Contingent Resources are the following:

Agbami field – 6 infill wells

Six further infill drilling opportunities (4 oil producers and 2 water injectors) were identified in the Agbami field, providing both acceleration and incremental recovery in developed areas of the field. Additional work is required to select the best candidate drilling locations from these and other opportunities, using the new 4DM3 seismic to be acquired in 2024. The first production from these wells is planned for 2027. The wells are estimated to cost approximately $521 million for drilling and completion, with an additional $147 million for facilities to tie-in the wells to the existing facilities. RISC has classified the project as Development on Hold.

Akpo field – 5 infill wells

The operator is currently evaluating 5 infill wells to be drilled in 2025. The wells are contingent on the 4DM4 seismic currently underway. Estimated recovery is approximately 5 MMbbl and 10 Bcf per well, however, the well locations are not yet firm. Drilling is currently scheduled for 4Q 2025 to 1Q 2026, with first production in mid-2026. RISC has classified the project as Development Pending.

Akpo field - Miscible Gas Injection project

Combined with the gas blowdown project (which was reclassified as reserves at YE2023) is the commencement of Miscible Gas Injection (MGI) project. This is planned with one well in 2026, two wells in 2029 and one well commencing production in 2033. The miscible gas injection in Upper A, Lower A and EF are simulated to create a reasonable incremental recovery of circa 40 MMstb. This project is dependent upon D reservoir gas blowdown to provide the gas for miscible injection. The project is also contingent on the results of a pilot well, expected by 2026. The cost forecasts associated with this project are $110 million for drilling and completion and $120 million for the facilities.

RISC has classified the MGI project as Development Unclarified.

Preowei field - 8 additional wells

These wells are in addition to the Preowei development (classified as Reserves). The wells are currently planned to be drilled in 2029. Capital costs are forecast to be approximately $372 million, with $292 million for the wells and $80 million for subsea facilities. There remains significant subsurface uncertainty, so the additional wells are contingent on the outcomes of the initial development stage. RISC has classified the project as Development On Hold.

Ikija - Development of discovered resources

Ikija is an undeveloped discovery in OML 127. It is planned as a tie-back to the Agbami FPSO, with first oil expected in 2032. Capital costs are forecast to be approximately $1,011 million and include: $103 million for an appraisal well; $403 million for 4 development wells in 2030-2031; and $505 million for facilities. There is significant subsurface uncertainty which will need further technical maturity and further appraisal. There is no firm plan for the development concept, with both depletion and water injection being considered. Additionally, commercial and fiscal terms are not ready to enable tie-back to the Agbami unit. RISC classified the project as Development Unclarified.

Egina South - Development of discovered resources

The Egina South Discovery lies 20 km southwest of the Egina Field. The reservoir intervals are similar to the main Egina field. First oil expected in 2030. Capital costs are forecast to be approximately $1,352 million for a 12 well subsea tieback which includes $619 million for wells and $680 million for facilities and $53 million for an appraisal well. The operator is revising the subsurface model but the impact on STOIIP and recoverable volumes are not available. A further appraisal well may also be required. RISC has classified the project as Development Unclarified.

Chance of Development

Quantifying the chance of development requires consideration of both economic contingencies and other contingencies such as legal, regulatory, market access, political, social license, internal and external approvals and commitment to project finance and development timing. As many of these factors are extremely difficult to quantify, the Chance of Development is uncertain and must be used with caution.

RISC has estimated the numerical value of the Chance of Development for each of the Contingent Resources:

- Agbami field (6 new infill wells): 63%
- Akpo field 5 infill wells: 90%
- Akpo field miscible gas injection: 20%
- Preowei field (8 additional wells): 56%
- Ikija (development of discovered resources): 19%
- Egina South (development of discovered resources): 58%

The primary risks related to these resources are (a) lack of technical and commercial maturity, (b) economic factors, (c) commitment of the Partnership to develop, and (d) development timing.

There is uncertainty that it will be commercially viable to produce any portion of these resources.

The total Contingent Resources related to the 1C, 2C, 3C and Risked Best Estimates are in the table below.

Contingent Resources (Forecast Prices and Costs)				
Nigeria (OML 127 and PML 2, PML 3, PML 4 & PPL 261)	**Light & Medium Oil (MMstb)**		**Conventional Natural Gas (Bscf)**	
	Gross	**Net**	**Gross**	**Net**
Low Estimate (1C)	9.9	12.4	-5.8	-5.8
Best Estimate (2C)	15.8	18.3	-1.5	-1.5
High Estimate (3C)	20.0	22.2	12.5	12.5
Risked Best Estimate	7.0	7.8	4.2	4.2

Notes:

1. Gross Company volumes are the total project sales volumes multiplied by AOC's share of Prime's working interest.
2. Net oil volumes are AOC's share of Prime's net entitlement.
3. Gross and net sales gas volumes are based on AOC's share of Prime's working interest.
4. The "Risked Best Estimate" Contingent Resources account for the Chance of Development, which is defined as the probability of a project being commercially viable.
5. The negative gas resources in the 1C and 2C cases are attributable to the Akpo miscible gas injection project. The project requires additional gas to be injected so the incremental gas production is negative. Total gas production in the 3C case is enough to cover the additional gas required for injection, hence the positive resources.

The following table discloses, in aggregate, the net present value of the future net revenue attributable to the Contingent Resource categories in the preceding table that are in the Development Pending project maturity sub-class. At year-end 2023, the project(s) in this sub-class relates to the 5 infill wells at Akpo. These NPVs are estimated using forecast prices and costs, before deducting future income tax expenses, and calculated without discount and using discount rates of 0 percent, 5 percent, 10 percent, 15 percent, and 20 percent.

Summary of Net Present Values of Future Net Revenue Forecast Prices and Costs					
Net Present Values of Future Net Revenue ($ million)	**Before Income Taxes Discounted at (%/Year)**				
Contingent Resources Category	**0**	**5**	**10**	**15**	**20**
1C	67	48	36	27	20
2C	130	89	65	49	38
3C	184	130	95	71	55

Notes:

1. Table includes the Contingent Resources in the Development Pending project maturity sub-class. The only project in this sub-class is the 5 infill wells at Akpo.
2. Figures in table may not add precisely due to rounding.
3. Units are US$ million.

An estimate of risked net present value of future net revenue of Contingent Resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the Company proceeding with the required investment. It includes Contingent Resources that are considered too uncertain with respect to the chance of development to be classified as Reserves. There is uncertainty that the risked net present value of future net revenue will be realized.

Item 7.2 Prospective Resources Data

RISC has prepared an audit of the crude oil and conventional natural gas Prospective Resources as of December 31 2023 for AOC.

The Prospective Resources are contained in the following licence:

South Africa – Block 3B/4B

A total of 24 prospects have been identified in the block (10 in the Central Area and 14 in the Northern Area). Two of these have been identified as the main prospects (Fan-SA and Aardwolf) which could act as a development hub for smaller discoveries at a later stage.

The prospect traps are predominantly stratigraphic in nature with lateral extent defined by facies changes from sands to mudstones. The reservoir targets exist at several stratigraphic levels in the Cretaceous: Upper Cretaceous age sandstones deposited in turbidite channel and fan systems at the slope margin, Cenomanian-Turonian age sandstones deposited in turbidite channel and fan systems at the slope margin and on the outer slope, and Albian sandstones deposited as turbidites as basin floor fans.

Based on recent regional discoveries, the targeted hydrocarbons are a light and medium oil, with associated gas condensate and gas.

Once a commercial discovery is made and developed, the Minimum Economic Field Size for commercial development could be reduced for subsequent discoveries, particularly for those in close proximity. Subsequent discoveries would potentially benefit from reduced capex and opex costs required to connect into existing infrastructure.

The gross unrisked Undiscovered Petroleum Initially-In-Place (UPIIP) and gross unrisked Prospective Resources for the two main prospects are presented in the table below.

Gross Unrisked UPIIP and Gross Unrisked Prospective Resources									
Prospect Name	**Unrisked UPIIP (STOIIP)**			**Unrisked Prospective Resources – Light & Medium Oil (MMstb)**			**Unrisked Prospective Resources – Assoc. Gas (Bcf)**		
Classification	**P90**	**P50**	**P10**	**1U (P90)**	**2U (P50)**	**3U (P10)**	**1U (P90)**	**2U (P50)**	**3U (P10)**
Fan-SA	1,118	2,066	3,777	277	518	951	504	953	1,767
Aardwolf	903	1,313	1,884	222	327	475	384	586	882
TOTAL	2,021	**3,379**	5,661	499	**845**	1,426	888	**1,539**	2,649

Notes:

1. Gross volumes in this table are 100% of resources attributable to Exploration Right.
2. Arithmetic aggregation: RISC cautions that the 1U aggregate quantities may be conservative estimates and the 3U aggregate quantities may be optimistic due to portfolio effects.
3. These are Unrisked and Undiscovered volumes.

Chance of Discovery and Chance of Development

Prospective Resources are estimates of what may be recovered if a discovery is made and developed. Not all exploration projects will result in discoveries and not all discoveries will be developed. The chance that an exploration project will result in the discovery of petroleum is referred to as the Chance of Discovery. RISC reviewed and quality controlled the Chance of Discovery derived by AOC for each prospect by using a five-component base analysis consisting of Source, Migration, Reservoir, Trap and Containment. RISC then modified the Chance of Discovery of each prospect following analysis of the quality of seismic attributes (such as possible fluid indicators).

Quantifying the Chance of Development requires consideration of both economic contingencies and other contingencies such as legal, regulatory, market access, political, social license, internal and external approvals and commitment to project finance and development timing. As many of these factors are extremely difficult to quantify, the Chance of Development is uncertain and must be used with caution.

RISC has estimated the numerical value of the Chance of Discovery and Chance of Development for each of the Prospective Resources:

Chance of Discovery and Chance of Development for each of the Prospective Resources				
Country and Block	**Prospect Name**	**Chance of Discovery**	**Chance of Development**	**Chance of Commerciality**
South Africa, Block 3B/4B	Fan-SA	29%	75%	21%
	Aardwolf	17%	75%	12%

Notes:

1. Chance of Commerciality is the product of the Chance of discovery and the Chance of Development.

The primary risks related to these resources are (a) discovery of hydrocarbons, (b) lack of technical and commercial maturity, (c) economic factors, (d) commitment of the Partnership to develop, and (e) development timing.

There is uncertainty that it will be commercially viable to produce any portion of these resources.

The Prospective Resources related to the Risked Best Estimates, calculated using the Unrisked Best Estimate and the Chance of Commerciality, are presented in the table below.

Risked Prospective Resources					
Risked Best Estimate		**Light & Medium Oil (MMstb)**		**Conventional Natural Gas (Bscf)**	
		Gross	**Net**	**Gross**	**Net**
South Africa, Block 3B/4B (AOC 26.25% interest)	Fan-SA	111	29	204	54
	Aardwolf	41	11	73	19
	Total	**152**	**40**	**277**	**73**
All Prospects	**Total**	**300**	**157**	**709**	**419**

Notes:

1. Figures in table may not add precisely due to rounding.
2. Gross volumes are the total project sales volumes.
3. Net volumes are the total project sales volumes multiplied by AOC's share of working interest.
4. The "Risked Best Estimate" Prospective Resources account for the Chance of Commerciality (ie the Chance of Discovery multiplied by the Chance of Development).

Item 7.3 Forecast Prices Used in Estimates

The pricing assumptions used for estimating Contingent Resources are the same as the pricing assumptions disclosed in Part 3 of this Form.

4. Form NI 51-101 F2

Form NI 51-101 F2

Report on Reserves data, Contingent Resources data and Prospective Resources data by Independent Qualified Reserves Evaluator or Auditor

To the board of directors of Africa Oil Corp. (the "Company"):

1. Due to different levels of technical maturity of assets in the portfolio, some assets underwent an audit, whilst others were evaluated in detail. We have audited and evaluated the Company's Reserves data, Contingent Resources data, and Prospective Resources data, as at 31 December 2023. The Reserves data are estimates of proved Reserves and probable Reserves and related future net revenue as at 31 December 2023, estimated using forecast prices and costs. The Contingent Resources data are risked estimates of volume of Contingent Resources and related risked net present value of future net revenue as at 31 December 2023 (for Development Pending projects), estimated using forecast prices and costs.
2. The Reserves data, Contingent Resources data and Prospective Resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the Reserves data, Contingent Resources data and Prospective Resources data based on our audit and evaluation.
3. We carried out our audit and evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
4. Those standards require that we plan and perform an audit and evaluation to obtain reasonable assurance as to whether the Reserves data, Contingent Resources data and Prospective Resources data are free of material misstatement. An audit and evaluation also includes assessing whether the Reserves data, Contingent Resources data and Prospective Resources data are in accordance with principles and definitions presented in the COGE Handbook.
5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable Reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the Reserves data of the Company audited and evaluated for the year ended 31 December 2023, and identifies the respective portions thereof that we have audited and evaluated and reported on to the Company's management:

US$ million			**Proved + Probable Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)**			
Independent Qualified Reserves Evaluator or Auditor	Effective Date of Audit/Evaluation Report	Location of Reserves	Audited	Evaluated	Reviewed	Total
RISC	31 December 2023	Nigeria	1,714		-	1,714

6. The following tables set forth the risked volume and risked net present value of future net revenue of Contingent Resources (before deduction of income taxes) attributed to Contingent Resources, estimated using forecast prices and costs and calculated using a discount rate of 10%, included in the Company's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the Contingent Resources data that we have audited and evaluated and reported on to the Company's management:

US$ million	**Asset Description**				**Risked Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)**		
Classification	Independent Qualified Reserves Evaluator/ Auditor	Effective Date of Audit/ Evaluation Report	Location of Resources Other than Reserves	Risked Volume	Audited	Evaluated	Total
Development Pending Contingent Resources (2C)	RISC	31 December 2023	Nigeria	Oil: 0.8 MMstb Gas: -1.9 Bscf	64.7		64.7

Notes

1. The risked NPV includes only the Contingent Resources in the Development Pending sub-class.

Classification	**Independent Qualified Reserves Auditor**	**Effective Date of Audit Report**	**Location of Resources Other than Reserves**	**Risked Oil Volume (MMstb)**	**Risked Gas Volume (Bscf)**
Contingent Resources* (2C)	RISC	31 December 2023	Nigeria	7.0	6.1

Notes

1. The volumes are for all other project maturity subclasses (i.e. excluding Development Pending)

7. In our opinion, the Reserves data, Contingent Resources data and Prospective Resources data respectively audited and evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the Reserves data, Contingent Resources data and Prospective Resources data that we reviewed but did not audit or evaluate.
8. We have no responsibility to update our reports referred to in paragraphs 5 and 6 for events and circumstances occurring after the effective date of our reports.
9. Since the Reserves data, Contingent Resources data and Prospective Resources data are based on judgements regarding future events, the actual results will vary and the variations may be material.

Executed as to our report referred to above:

26 February 2024

RISC (UK) Limited

20 St Dunstan's Hill

London

EC3R 8HL

United Kingdom

Gavin Ward

Gavin Ward

Director

For and on behalf of RISC (UK) Limited

5. Declarations

5.1. Terms of Engagement

This report, any advice, opinions or other deliverables are provided pursuant to the Engagement Contract agreed to and executed by the Client and RISC.

5.2. Standard

Reserves and Resources are reported in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

5.3. Limitations

The assessment of petroleum assets is subject to uncertainty because it involves judgments on many variables that cannot be precisely assessed, including reserves/resources, future oil and gas production rates, the costs associated with producing these volumes, access to product markets, product prices and the potential impact of fiscal/regulatory changes.

The statements and opinions attributable to RISC are given in good faith and in the belief that such statements are neither false nor misleading. In carrying out its tasks, RISC has considered and relied upon information obtained from Prime and AOC as well as information in the public domain. The information provided to RISC has included electronic information supplemented with discussions between RISC and key Prime and AOC staff.

While every effort has been made to verify data and resolve apparent inconsistencies, neither RISC nor its servants accept any liability, except any liability which cannot be excluded by law, for its accuracy, nor do we warrant that our enquiries have revealed all of the matters, which an extensive examination may disclose.

In particular, we have not independently verified property title, encumbrances, regulations that apply to this asset(s). RISC has also not audited the opening balances at the valuation date of past recovered and unrecovered development and exploration costs, undepreciated past development costs and tax losses.

We believe our review and conclusions are sound but no warranty of accuracy or reliability is given to our conclusions.

Our review was carried out only for the purpose referred to above and may not have relevance in other contexts.

5.4. Use of advice or opinion and reliance:

a) The Report is confidential and is for the Sole benefit of the Client. ***It may not be relied upon by any 3rd party.***

b) RISC grants permission for the report to be disclosed, on condition of confidentiality:

   i. to directors, officers, employees and contractors of the Client;

   ii. to its professional advisers on a non-reliance basis;

   iii. to a party in which the Client has a controlling interest on a non-reliance basis;

   iv. to the extent required by law; or

   v. as otherwise agreed to in writing by RISC in accordance with the Engagement Contract.

5.5. Independence

RISC has no pecuniary interest, other than to the extent of the professional fees receivable for the preparation of this report, or other interest in the assets evaluated, that could reasonably be regarded as affecting our ability to give an unbiased view of these assets.

RISC makes the following disclosures:

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