AFRICA OIL CORP.

REPORT TO SHAREHOLDERS

FOR THE PERIOD ENDED MARCH 31, 2025

AFRICAOILCORP.COM

GLOSSARY

A	"Africa Energy"	means Africa Energy Corp. an international oil and gas exploration company that holds an effective 4.9% participating interest in the Exploration Right for Block 11B/12B offshore South Africa.
	"Africa Oil", "AOC", or the "Company"	means Africa Oil Corp.
	"Amalgamation Agreement"	means the definitive agreement between the Company, BTG Oil & Gas and BTG Holding the entity which holds the interests of BTG Oil & Gas in Prime, to reorganize and consolidate their respective 50:50 shareholdings in Prime.
	"Applicable law"	means all laws and regulations issued by authorities that have appropriate jurisdiction over the Company.
	"Azinam"	means Azinam Ltd.
B	"Bcf"	means billion cubic feet.
	"Blocks"	means blocks 2912 and 2913B.
	"boepd"	means barrels of oil equivalent per day.
	"BTG Holding"	means BTG Pactual Holding S.a.r.l.
	"BTG Oil & Gas"	means BTG Pactual Oil & Gas S.a.r.l.
C	"CGU"	means Cash Generating Unit. A Cash Generating Unit is defined as assets that are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets.
	"Chevron"	means Chevron Corp.
	"CIT"	means Corporate Income Tax.
	"Concessions", "PSC" or "Production Sharing Contract"	means concessions, production sharing contracts and other similar 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.
	"Corporate Facility"	means the $200.0 million facility dated October 20, 2022, with a three-year term, as amended from time to time.
D	"DD&A"	means Depreciation, Depletion and Amortization.
	"DST"	means Drill Stem Testing.
E	"EPS"	means Early Production System.
	"EBITDAX"	means Earnings Before Interest, Taxes, Depreciation & Impairment, Amortization and Exploration Expenses.
	"Eco"	means Eco (Atlantic) Oil & Gas Ltd, an international oil and gas exploration company that holds working interests in four exploration Blocks offshore Namibia and operates one exploration Block offshore South Africa and is party with the Company in Block 3B/4B, offshore South Africa and holds working interest in two exploration Blocks offshore Guyana.
	"Entitlement production"	means production that is calculated using the economic interest methodology and includes cost oil, profit oil, tax oil and royalty oil.
	"ESG"	means Environmental, Social and Governance.
	"ESHS"	means Environmental, Social, Health and Safety.
	"ESIA"	means Environmental and Social Impact Assessment.
F	"FCF"	means Free Cash Flow.
	"FEED"	means Front End Engineering and Design.
	"FID"	means Final Investment Decision.
	"FPSO"	means Floating Production Storage and Offloading.
I	"IFRS Accounting Standards"	means International Financial Reporting Standards as issued by the International Accounting Standards Board.
	"Impact"	means Impact Oil and Gas Ltd, a privately owned exploration company with a strategic focus on large scale, mid to deep water plays of sufficient materiality to be of interest to major companies. Impact has an asset base across the offshore margins of Southern and West Africa.

J	"JV"	means Joint Venture.
K	"Kenya entities"	means Centric Energy Kenya Limited, Africa Oil Kenya B.V Branch and Africa Oil Turkana Limited.
L	"LTI"	means loss time injury.
	"LTIP"	means Long Term Incentive Plan.
M	"Mcf"	means million cubic feet.
	"MD&A"	means Management's Discussion and Analysis.
	"Mbbl" and "MMbbl"	means one thousand and one million barrels, respectively.
	"Mboe" and "MMboe"	means thousands of barrels of oil equivalent and millions of barrels of oil equivalent, respectively.
N	"NCIB"	means Normal Course Issuer Bid.
	"NI 51-101"	means National Instrument 51-101 – Standards 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 52-109"	means National Instrument 52-109 – Certification of Disclosure in Issuers' Annual and Interim Filings and the companion policies and forms thereto, as amended from time to time.
	"NUPRC"	means Nigerian Upstream Petroleum Regulatory Commission.
P	"Petrovida"	means PetroVida Holding B.V.
	"PIA"	means Petroleum Industry Act.
	"PML"	means Petroleum Mining Lease.
	"PML 2"	means the Petroleum Mining Lease containing the Akpo field.
	"PML 3"	means the Petroleum Mining Lease containing the Egina field.
	"PML 4"	means the Petroleum Mining Lease containing the Preowei field.
	"PML 52"	means the Petroleum Mining Lease containing the Agbami field.
	"PPL"	means Petroleum Prospecting License.
	"PPL 261"	means the Petroleum Prospecting License containing the South Egina prospect.
	"PPT"	means Profit Petroleum Tax.
	"Prime" or "Prime Oil & Gas Coöperatief U.A."	means Prime Oil & Gas Coöperatief U.A., previously known as Prime Oil & Gas B.V., a company that holds interests in deepwater Nigeria production and development assets.
	"PSA"	means Petroleum Sharing Agreement.
	"PSC"	means Production Sharing Contract.
	"PSU"	means Performance Share Unit.
R	"RBL"	means Reserves Based Lending.
	"RSU"	means Restricted Share Unit.
S	"spud" or "spudded"	means the initial drilling for an oil well.
T	"TotalEnergies"	means TotalEnergies SE and subsidiaries.
	"TSX"	means Toronto Stock Exchange.
U	"US"	means United States.
W	"WI"	means working interest.
	"WI production"	means production based on the percentage of working interest owned.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The Management's Discussion and Analysis ("MD&A") focuses on significant factors that have affected the Company during the three months ended March 31, 2025, and such factors that may affect its future performance. To better understand the MD&A, it should be read in conjunction with the Company's unaudited interim condensed consolidated financial statements for the three months ended March 31, 2025, and 2024, and also should be read in conjunction with the audited consolidated financial statements for the years ended December 31, 2024, and 2023, and related notes thereto.

The financial information in this MD&A is derived from the Company's unaudited interim condensed consolidated financial statements which have been prepared in US dollars, in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS Accounting Standards").

This MD&A was reviewed and approved by the Board of Directors. The effective date of this MD&A is May 14, 2025.

Additional information about the Company and its business activities is available on the Company's website at www.africaoilcorp.com and on SEDAR at www.sedar.com.

PROFILE AND STRATEGY

Africa Oil is a Canadian oil and gas company with producing and development assets in deep-water offshore Nigeria. The Company also has a portfolio of development and exploration assets in West and South of Africa.

The Company's Common Shares are listed on the Toronto Stock Exchange in Canada and the Nasdaq Stockholm Exchange in Sweden, under the symbol 'AOI'.

Africa Oil's long-term objective is to implement a steady and predictable total shareholder returns model underpinned by an enhanced base dividend policy, whilst delivering organic growth from its core assets and pursuing disciplined inorganic growth opportunities focused on producing assets. This plan is supported by the Company's high netback production assets in Nigeria that are included in its interests in Petroleum Mining Leases ("PMLs") 2, 3, 4 and 52. These PMLs provide the Company with a long-life cash flowing asset base, to support its business objectives over the long term, and also present development opportunities for supporting future production.

The Company's other core assets are comprised of its Orange Basin opportunity set including Blocks 2912 and 2913B offshore Namibia and Block 3B/4B, offshore South Africa, as well as Equatorial Guinean exploration blocks (EG-18 and EG-31).

The Company is a unique investment opportunity, amongst its publicly-listed independent E&P peer group, for its Orange Basin opportunity set that includes an effective interest in the Venus light oil and associated gas discovery offshore Namibia. The Venus discovery, understood to be the largest oil discovery globally in 2022, has partially de-risked a new petroleum province in the Orange Basin that has significant prospectivity.

HIGHLIGHTS AND OUTLOOK

FIRST QUARTER 2025 AND POST PERIOD HIGHLIGHTS

- Closed the amalgamation transaction to take full control of Prime, doubling AOC's reserves and production, and implemented a new policy to effectively triple dividend per share.
- During Q1 2025, (presented as if the amalgamation had closed on January 1, 2025):
  - Achieved average daily W.I. and entitlement production of 33,400 boepd and 37,700 boepd respectively, in line with expectations.
  - Sold five cargoes (approximately 5 MMbbl) at an average sales price of $79.5/bbl versus an average Dated Brent for the same period of $75.7/bbl;
  - Recorded cashflow from operations before working capital adjustment of $99.8 million.
  - Received a distribution of $31.6 million from Impact.
  - Pro-actively reduced the RBL debt balance by $130.0 million to $620.0 million at the end of Q1 2025, reducing interest expenses.
  - End of Q1 2025 cash balance of $428.4 million, resulting in a net debt position of $191.6 million with a Net Debt/ EBITDAX of 0.3x as at March 31, 2025.
- During Q1 2025 with the amalgamation closing on March 19, 2025, recorded net income of $50.9 million ($0.11 per share).
- Post end of Q1 2025:
  - Distributed the first quarterly cash dividend of approximately $25.0 million ($0.0371 per share) in April 2025.
  - AOC's Board has declared the second quarterly dividend in 2025 of approximately $25.0 million ($0.0371 per share) payable in June 2025 to shareholders of record at the close of business on May 26, 2025.
  - The Company reduced the RBL debt balance by a further $80.0 million and has commenced the process to cancel its $65.0 million Corporate Facility, which remains undrawn.

FINANCIAL SUMMARY (1)

		Three months ended		Year ended
	Unit	March 31, 2025	March 31, 2024	December 31, 2024
AOC highlights				
Net income/ (loss)	$'m	50.9	3.5	(279.1)
Net income/ (loss) per share – basic	*$/ share*	*0.11* (2)	*0.01*	*(0.62)*
Net debt position(3)	$'m	191.6	285.9	289.1
WI production (3)	boepd	33,400	34,200	34,000
Entitlement production (3)	boepd	37,700	40,200	38,800
EBITDAX (4)	$'m	141.6	n/a	n/a
Cash flow from operations (4, 5)	$'m	99.8	n/a	n/a
Free Cash Flow (4)	$'m	121.6	n/a	n/a

(1) The table includes non-GAAP measures. Definitions and reconciliations to these non-GAAP measures are provided on pages 14-16.

(2) Based on the Q1 2025 weighted average number of shares outstanding of 449,431,803 which accounts for the newly issued shares to BTG Oil & Gas on March 19. 2025.

(3) Net debt position and production numbers as presented for the comparative periods includes 100 percent of Prime to be comparable with March 31, 2025, net debt position and production numbers for the three months period ended March 31, 2025.

(4) Highlights are reported for the year 2025 only as if the amalgamation had closed on January 1, 2025

(5) Cash flow from operations before working capital and interest payments.

HIGHLIGHTS AND OUTLOOK - CONTINUED

OUTLOOK

Shareholder Returns

The first dividend under the Company's enlarged base dividend policy of $25.0 million was paid during April 2025 and the Company's Board has declared the second dividend in 2025 for distribution in June 2025, to shareholders of record at the close of business on May 26, 2025.

The Company's Board views the base annual distribution policy to be prudent with due consideration for its capital allocation options and the priority of maintaining a strong balance sheet in a range of market scenarios.

Nigeria

The Company remains focused on working with its JV partners to sustain and enhance production through targeted drilling and optimisation initiatives on its three producing fields in deepwater Nigeria.

At Egina, two producers were drilled in Q1 2025 with both expected to come onstream in Q2 2025. On Akpo, a well intervention and the drilling of one development well are planned for Q2 2025. A break to the rig campaign is planned from Q4 2025 to allow for interpretation of the available 4D seismic data and drilled well results to enable maturation of future infill drilling candidates.

The Company's Nigerian portfolio includes infrastructure-led exploration assets that in case of commercial discovery success, could potentially present attractive short cycle, high return investment opportunities that would benefit from the existing facilities. One such opportunity, which is being progressed towards drilling is the Akpo Far East prospect with an unrisked, best estimate, gross field prospective resource volume of 143.6 MMboe. The targeted hydrocarbons are predicted to be light, high gas-oil ratio ("GOR") oil equivalent to those found in the Akpo field. If successful, initial production could be achieved from existing production manifolds with the potential to materially increase reserves on the Akpo Field.

At Agbami, further planned maintenance including a full field shutdown in Q4 2025, is expected to support long-term performance with 4D seismic interpretation continuing in support of the upcoming drilling campaign. Rig and well long lead items contracting is underway, alongside the placement of orders for subsea trees, in preparation for the commencement of the infill drilling campaign in 2027.

For Preowei, studies of the fast-track seismic data are continuing to further derisk the identified upside opportunities to enhance recoverable volumes. In parallel, the reengagement of the front-end engineering and design ("FEED") contractor is planned in order to carry out additional evaluation aimed at optimizing the Preowei engineering, procurement, construction and installation ("EPCI") phase costs.

Namibia Orange Basin Development and Exploration, Blocks 2912 and 2913B

The Venus Field is expected to be the first development area in Block 2913B. The Venus development plan is for up to 40 subsea wells tied back to a floating production, storage and offloading ("FPSO") platform that can handle peak output of 160,000 barrels per day of oil.

- Project preparation and decision-making –
  - Front-End Engineering Designs ("FEED"): Q2 – Q4 2025
  - ESIA submission to authorities: Q4 2025
  - Final Investment Decision ("FID") could be made during H1 2026

The latest exploration drilling campaign was completed on April 25, 2025, with the drilling rig demobilized. The Company expects the next drilling campaign to commence during Q4 2025 and notes that TotalEnergies has publicly identified Olympe-1X, on Block 2912, as a possible target for this campaign.

HIGHLIGHTS AND OUTLOOK - CONTINUED

South Africa Orange Basin, Block 3B/4B

Following the granting of an Environmental Authorization for exploration activities (drilling of up to 5 exploration wells) by the Department of Mineral Resources and Energy for the Republic of South Africa on September 16, 2024, the legislative notification and appeals process continues to progress with the relevant regulatory agencies. The operator has stated that with the approval process progressing the current plan is to drill the first exploration well on Block 3B/4B in 2026 and has identified Nayla, a prospect that lies in the northwest of the license area as the potential drilling target.

Equatorial Guinea, Blocks EG-18 and EG-1

The Company is in active dialogue with industry parties to attract farm in parties on both blocks, with the aspiration of completing the exercise by the end of Q3 2025.

If the Company is successful in attracting farminee partner(s) for these blocks, subject to customary consents and approvals including governmental and regulatory permissions, the Company anticipates that newly formed JVs could plan for exploration drilling in late 2026 or during 2027. However, there is no guarantee the Company can secure farminee partners on acceptable terms and it does not intend to undertake exploration drilling on a sole risk basis if it is unsuccessful in its farm down campaign.

SUMMARY OF 2025 MANAGEMENT GUIDANCE AND ACTUALS

The Company's full-year 2025 Management Guidance is unchanged and is repeated here for completeness. These estimates are based on a 2025 average Brent price of $75.0 per barrel. At an average Brent price of $85.0 per barrel the mid-point of the cash flow from operations guidance range is estimated to increase by approximately 19%, and at an average of $65.0 per barrel the mid-point is estimated to decrease by approximately 12%.

	2025 Guidance	Q1 2025 Actuals
WI production (kboepd) (1)	28.0 – 33.0	33.4
Entitlement production (kboepd) (2)	32.0 – 37.0	37.7
EBITDAX ($ million) (3)	500 - 600	141.6
Cash flow from operations ($ million) (3)	320 - 370	99.8
Capital investment ($ million)	150 - 190	28.2

(1) Aggregate oil equivalent production data comprised of light and medium crude oil and conventional natural gas production net to the Company's W.I. in Agbami, Akpo and Egina fields. These production rates only include sold gas volumes and not those volumes used for fuel, reinjected or flared.

(2) Entitlement production is calculated using the economic interest methodology and includes cost recovery oil, royalty oil and profit oil and is different from working interest production that is calculated based on project volumes multiplied by the Company's effective working interest in each license.

(3) This table includes non-GAAP measures that do not have a standardized meaning prescribed by IFRS Accounting Standards and, therefore, may not be comparable with the calculation of similar measures by other companies. The Company believes that the presentation of these non-GAAP figures provides useful information to investors and shareholders as the measures provide increased transparency. EBITDAX is a non-GAAP measure. This is used as a performance measure to understand the financial performance from the Company's business operations without including the effects of the capital structure, tax rates, depreciation, depletion, amortization, impairment and exploration expenses.

Cash flow from operations before working capital and interest payments is a non-GAAP measure. This represents cash generated by removing the impact of working capital movements from cash generated by operating activities. It is a measure commonly used to better understand cash flow from operations across periods on a consistent basis, and when viewed in combination with the Company's results provides a more complete understanding of the factors and trends affecting the Company's performance

THE COMPANY'S SHAREHOLDING AND WORKING INTERESTS

The Company's material interests and material exploration partnership interests as at March 31, 2025, are summarized in the following table:

Africa Oil's Direct Working Interests [1,2]

Country	Concession	License renewal	Working Interests	
NIGERIA	PML 52 and PPL 2003[3]	November 24, 2044	AOC	8%
			Chevron Corporation	32%
			Famfa Oil	60% (carried)
	PML 2, 3, 4 and PPL 261 – PSA [4]	May 24, 2043	AOC	32%
			TotalEnergies	48%
			SAPETRO	20% (carried)
SOUTH AFRICA	Block 3B/4B	October 26, 2024 [5]	AOC	18%
			TotalEnergies (Operator)	33%
			QatarEnergy	24%
			Azinam	5.25%
			Ricocure (Pty) Ltd	19.75%
EQUATORIAL GUINEA	EG-18 EG-31	March 1, 2026	AOC (Operator)	80%
			GEPetrol	20%

Africa Oil's Shareholding in Impact (39.5%)

Country	Concession	License renewal	Working Interests	
NAMIBIA	PEL 56 (Block 2913B)	March 31, 2026	Impact	9.5%
			TotalEnergies	50.5%
			QatarEnergy	30%
			NAMCOR	10% (carried)
	PEL 91 (Block 2912)	October 1, 2027	Impact	9.5%
			TotalEnergies	47.2%
			QatarEnergy	28.3%
			NAMCOR	15% (carried)

(1) Net WI are subject to back-in rights or carried WI, if any, of the respective governments or national oil companies of the host governments.

(2) The Company has agreed with its JV parties its withdrawal from the entirety of the production sharing contracts and joint operating agreements for Blocks 10BB, 13T and 10BA in Kenya with effect on and from June 30, 2023. The Company is waiting for government consent to complete its withdrawal and the transfer of rights and future obligations.

(3) Production currently from PML 52 and potential future production from PPL 2003 is covered by a PSA framework, in which Prime owns a 8% WI.

(4) 50% of the production (currently from PMLs 2 and 3, future production from PML 4 and potential future production from PPL 261) is covered by a PSA framework, in which Prime owns a 32% WI. Prime's net WI in these assets is therefore 16%.

(5) The operator has submitted an application for license renewal. This is currently awaiting Government approval.

Information on the Company's equity interests in Africa Energy and Impact is included in 'Equity Investments in Associates' on pages 19-20.

BUSINESS UPDATE

Macroeconomic conditions

International oil prices in Q1 2025 exhibited overall moderation where, after an initial surge in January, there was an extended decline followed by a recovery in March. The average Bloomberg Dated Brent was $75.7/bbl compared to the average of $74.7/bbl and $80.7/bbl observed in Q4 2024 and full year 2024 respectively. In Q1 2025, Bloomberg Dated Brent traded up to a high of $83.0/bbl and a low of $69.8/bbl.

The price fluctuations in Q1 2025 were primarily due to underlying competing interactions between the global economic outlook and evolving supply dynamics. The uncertainty surrounding US tariffs resulted in concerns over economic slowdowns acting as a headwind for oil demand sentiment. This was compounded by OPEC+'s strategy of maintaining supply cuts being offset by increasing oil production from non-OPEC+ countries.

The Middle East conflict and the associated Red Sea route disruptions persisted into the first quarter. However, its direct oil market impact appeared relatively contained by logistical rerouting and supply flexibility. The new US sanctions imposed on Iran and Venezuela also contributed to market tightness mitigating further price decline.

Consequently, the current global market conditions and geopolitical risks continue to reinforce the attractiveness of potentially more secure supply from Atlantic basin sources, and West Africa in particular.

Nigeria economic environment

Following the rebasing of the Consumer Price Index by the Nigerian National Bureau of Statistics, the headline inflation rate fell to 24.8% in January 2025 from the previous record of 34.8% in December 2024. With the new 2024 base year, the upward inflation trend observed in 2024 appears to have been checked as the February and March inflation is given at 23.2% and 24.2%.

In the first quarter, petrol and diesel prices experienced some reduction due to increase domestic supply primarily by the Dangote Refinery. Additionally, the exchange rate showed relative stability compared to Q4 2024. Notwithstanding, high transportation costs, insecurity and energy prices persist and remain the key drivers for high food costs as the effects of the 2023 fuel subsidy removal and foreign exchange market reform continue to be felt. Notably, the Central Bank of Nigeria reached the decision to maintain the current interest rate at 27.5% in line with its interventions in 2024. Despite these signs of stabilization, the outlook for the rest of 2025 will depend greatly on sustained policy implementation, security improvements and proper navigation of global economic uncertainties.

Positively, Prime's Nigerian business activities continue to be minimally affected by domestic economic conditions, as its revenues are denominated in US Dollars. Moreover, the positioning of its producing assets in deepwater, offshore Nigeria effectively separates its operational environment from the security challenges encountered in the country's onshore areas.

SHAREHOLDER RETURNS

On March 20, 2025, the Company declared the first quarterly dividend of approximately $25.0 million or $0.0371 per share with payment during April 2025. The Company is pleased to announce that its Board has declared the distribution of the Company's second 2025 quarterly cash dividend of approximately $25.0 million or $0.0371 per share. This dividend will be payable on June 11, 2025, to shareholders of record at the close of business on May 26, 2025.

This dividend qualifies as an 'eligible dividend' for Canadian income tax purposes. Dividends for shares traded on the Toronto Stock Exchange ("TSX") will be paid in Canadian dollars on June 11, 2025; however, all US and foreign shareholders will receive USD funds. Dividends for shares traded on Nasdaq Stockholm will be paid in Swedish Krona in accordance with Euroclear principles on June 16, 2025.

To execute the payment of the dividend, a temporary administrative cross border transfer closure will be applied by Euroclear from May 22, 2025, up to and including May 26, 2025, during which period shares of the Company cannot be transferred between the TSX and Nasdaq Stockholm.

Payment to shareholders who are not residents of Canada will be net of any Canadian withholding taxes that may be applicable. For further details, please visit: https://africaoilcorp.com/investor-summary/total-shareholder-returns/.

Future dividend declarations are subject to customary Board approval and consents.

Pursuant to the Company's current Normal Course Issuer Bid ("NCIB") share repurchase program that was launched on December 6, 2024, Africa Oil is authorized to repurchase through the facilities of the TSX, Nasdaq Stockholm and/or alternative Canadian trading systems, as and when considered advisable by Africa Oil, up to 18,362,364 Common Shares of the Company, which represented 5% of its "public float" of 367,247,289 Common Shares as at November 22, 2024.

Purchases of Common Shares may occur over a period of up to twelve months commencing December 6, 2024, and ending on the earlier of December 5, 2025, the date on which the Company has purchased the maximum number of Common Shares permitted under the NCIB, and the date on which the NCIB is terminated by Africa Oil. There cannot be any assurances as to the number of Common Shares that will ultimately be acquired by the Company. Any Common Shares purchased by Africa Oil under the NCIB will be cancelled.

BUSINESS UPDATE - CONTINUED

During Q1 2025, the Company repurchased a total of 5.9 million shares at an average price of C$1.94 per share. Since the launch of the current NCIB program, the Company has repurchased a total of 8.4 million shares at an average price of C$1.89 per share.

In Canada, Bill C-59 sets out taxes on repurchases of equity, with a 2% tax applying to the net value of shares repurchased by any corporation resident in Canada whose shares are listed on a designated stock exchange. Bill C-59, was enacted on June 20, 2024, and the Company has paid the tax payable for shares purchased in 2024 and accrued for the tax payable on shares purchased during Q1 2025.

Group operations

On March 19, 2025, the Company completed the transaction with BTG Oil & Gas to consolidate its interest in Prime. The acquisition was completed by way of amalgamation whereby BTG Oil & Gas exchanged its 50 percent interest in Prime, held through its fully owned subsidiary BTG Pactual Holding S.à.r.l., in exchange for 239,828,655 newly issued shares in the Company.

The production numbers included in the narrative discussion below include 100 percent of Prime production numbers for all periods to have comparable production numbers for the purpose of this MD&A.

Production and Operations

Production Metrics – rounded

	Unit	Three months ended March 31, 2025	Three months ended March 31, 2024	Year ended December 31, 2024
Total gross field production	boepd	262,700	280,600	273,600
Average daily WI production (1)	boepd	33,400	34,200	34,000
Average daily entitlement production	boepd	37,700	40,200	38,800
Oil volumes sold	MMbbl	5.0	2.0	9.0
Gas volumes sold	bcf	5.0	4.0	17.4
Oil/gas percentage split	%	75%/25%	81%/19%	77%/23%

(1) Production allocation occurs periodically and can result in a change in production numbers previously reported.

The total gross field production in Q1 2025 was lower than Q1 2024, primarily due to the expected natural reservoir decline across all assets.

Performance across our deepwater portfolio remained robust in Q1 2025, with both Egina and Akpo fields delivering production ahead of expectations in the first quarter. At Akpo, the Akpo West wells continue to deliver above expectation supporting the continued strong performance and underpinning the consistency of the asset. On Egina, drilling operations resumed in January 2025, resulting in the successful completion of two new production wells, which are expected to come online in Q2 2025. Meanwhile, production at Agbami was temporarily impacted by scheduled compressor maintenance early in the quarter. These activities were executed as planned and are a key part of our strategy to safeguard long-term reliability and compression uptime on the asset.

Entitlement production is calculated using the economic interest methodology and includes cost oil, profit oil and royalty oil. It differs from WI production which is calculated based on field volumes multiplied by the Company's effective WI in each Block. Aggregate oil equivalent production data comprises of light and medium crude oil and conventional natural gas production net to the Company's WI in the Agbami, Akpo and Egina fields. These production rates only include sold gas volumes and not those volumes used for fuel, reinjected or flared.

In Q1 2025, Prime was allocated five oil liftings with a total sales volume of approximately 5.0 million barrels of oil at an average realized oil price of $79.5/bbl with one of these oil liftings occurring post amalgamation and therefore presented as revenue in the Company's interim condensed consolidated statement of net income and comprehensive income. In Q1 2024, Prime was allocated two oil liftings with total sales volume of approximately 2.0 million barrels at an average realized oil price of $85.5/bbl.

In 2024, Prime was allocated nine oil liftings with total sales volume of approximately 9.0 million barrels at an average realized oil price of $84.6/bbl.

BUSINESS UPDATE - CONTINUED

FINANCIAL

Total revenues, cost of sales, gross profit, opex/boe, tax and net debt numbers included in the narrative discussion below include 100 percent of Prime numbers for all periods to have comparable numbers for the purpose of this MD&A and includes certain adjustments and reclassifications in the comparative periods to conform with Africa Oil accounting policies and presentation in the Company's interim condensed consolidated statement of net income and comprehensive income following completion of the amalgamation.

Cash flow from operations, free cash flow, capex and EBITDAX numbers included in the narrative discussion below have been reported for the year 2025 only on as if the amalgamation had closed on January 1, 2025.

For this purpose, constructed Prime information to explain performance is included in the following tables to present on a consolidated basis net income for Q1 2025 and cash flow statement for Q1 2025 as if the amalgamation had closed on January 1, 2025, whereby the Africa Oil interim condensed consolidated statement of net income and comprehensive income and the Africa Oil interim condensed consolidated statement of cash flows for Q1 2025 are combined with the Prime statement of net income and comprehensive income and the Prime statement of cash flows for the period until March 19, 2025. Adjustments are included to conform Prime financial information with Africa Oil accounting policies and for any transactions between Africa Oil and Prime prior to amalgamation for the purpose of presenting constructed Prime information to explain performance.

Constructed Prime information for purposes of explaining performance
Interim condensed consolidated statement of net income

For the three months ended	AOC Q1 2025 per Financial Statements	Prime for period from January 1, 2025, to March 19, 2025	Adjustments [1]	March 31, 2025
Revenue	76.4	323.5	-	399.9
Cost of Sales				
Production costs	(51.2)	(187.4)	2.0	(236.6)
Depletion and decommissioning costs	(12.1)	(71.3)	-	(83.4)
	(63.3)	(258.7)	2.0	(320.0)
Gross profit	13.1	64.8	2.0	79.9
General and administrative expenses	(13.5)	(6.2)	-	(19.7)
Operating (loss)/ profit	(0.4)	58.6	2.0	60.2
Finance income	1.1	2.4	-	3.5
Finance expense	(2.8)	(21.3)	-	(24.1)
Net financial items	(1.7)	(18.9)	-	(20.6)
Share of profit from investment in joint venture	15.9	-	(15.9)	-
Share of loss from investments in associates	(2.0)	-	-	(2.0)
Reversal of impairment of investment in joint venture	42.9	-	(42.9)	-
Profit before tax	54.7	39.7	(56.8)	37.6
Income tax	(3.8)	(7.9)	-	(11.7)
Net income attributable to common shareholders	50.9	31.8	(56.8)	25.9

(1) Adjustments to remove items related to Prime as fully consolidated above.

BUSINESS UPDATE - CONTINUED

Interim condensed consolidated statement of cash flows

For the three months ended	AOC Q1 2025 per Financial Statements	Prime for period from January 1, 2025, to March 19, 2025	Adjustments (1)	March 31, 2025
Operations				
Profit before tax	54.7	39.7	(56.8)	37.6
Adjustments as per financial statements	(55.6)	59.0	58.8	62.2
Net cash (used)/ generated in operating activities before working capital	(0.9)	98.7	2.0	99.8
Changes in working capital	37.3	(25.7)	-	11.6
Net cash generated in operating activities	36.4	73.0	2.0	111.4
Investing				
Expenditures on oil and gas properties	(3.6)	(22.6)	(2.0)	(28.2)
Distribution received from joint venture	60.0	-	(60.0)	-
Distribution received from associates	31.6	-	-	31.6
Loan repaid by associated company	4.5	-	-	4.5
Interest income received	0.9	2.2	-	3.1
Cash acquired from Prime consolidation (2)	380.4	-	(381.3)	(0.9)
Net cash generated/ (used) in investing activities	473.8	(20.4)	(443.3)	10.1
Financing				
Repayment RBL Facility	(130.0)	-	-	(130.0)
Repayment of principal portion of lease commitments	(0.1)	-	-	(0.1)
Dividends paid to shareholders	-	(120.0)	120.0	-
Repurchase of share capital	(8.3)	-	-	(8.3)
Interest expense paid	(4.9)	(10.8)	-	(15.7)
Net cash used in financing activities	(143.3)	(130.8)	120.0	(154.1)
Foreign exchange variation on cash and cash equivalents	0.1	-	-	0.1
Total cash flow	367.0	(78.2)	(321.3)	(32.5)
Cash and cash equivalents, beginning of the period	61.4	399.5	-	460.9
Cash and cash equivalents, end of the period	428.4	321.3	(321.3)	428.4

(1) Adjustments to remove items related to Prime as Prime fully consolidated above

(2) Reflects impact of net cash movement on the level of BTG Pactual Holding S.à.r.l.

BUSINESS UPDATE - CONTINUED

Financial Metrics[1]

	Unit	Three months ended March 31, 2025	Three months ended March 31, 2024	Year ended December 31, 2024
Total revenues	$'m	399.9	176.6	782.7
Cost of Sales [2]	$'m	320.0	80.0	428.2
Gross profit	$'m	77.9	96.6	354.5
Opex/boe [3,4]	$/boe	13.4	10.4	10.3
Cash flow from operations before working capital	$'m	99.8	n/a	n/a
Cash flow from operations	$'m	111.4	n/a	n/a
Free cash flow	$'m	121.6	n/a	n/a
Free cash flow/boe [4]	$/boe	35.8	n/a	n/a
Tax	$'m	11.7	21.2	120.5
Capex	$'m	28.2	n/a	n/a
Net Debt	$'m	191.6	285.9	289.1
EBITDAX	$'m	141.6	n/a	n/a
Net Debt/EBITDAX [5]	ratio	0.3	n/a	n/a

(1) The table includes non-GAAP measures. Definitions and reconciliations to these non-GAAP measures are provided on pages 14-16.

(2) Given the nature of Prime's operations in terms of oil cargo liftings and the variability in their frequency from one quarter to next, the non-cash accounting treatment of underlift/overlift and the timing between recording revenues and receipts of sales cash, leads to high variability in quarterly financial metrics. Please refer to the commentary in the rest of this section for the specific details of this period's changes relative to the corresponding historical period.

(3) Opex represents direct production costs.

(4) Boe is calculated on an entitlement basis.

(5) Calculated based on Q1 2025 EBITDAX multiplied by 4.

Total revenues

	Unit	Three months ended March 31, 2025	Three months ended March 31, 2024	Year ended December 31, 2024
Oil revenue	$'m	394.5	171.0	762.2
Gas revenue	$'m	5.4	5.6	20.5
Total revenue	**$'m**	**399.9**	**176.6**	**782.7**
Realized oil prices [1]	$/bbl	79.5	85.5	84.6
Oil volumes sold	MMbbl	5.0	2.0	9.0
Realized gas prices	$/bcf	1.1	1.4	1.2
Gas volumes sold	Bcf	5.0	4.0	17.4

(1) Realized oil prices might be different to values calculated from the table above due to roundings.

The increase in oil revenue in Q1 2025 was mainly driven by higher liftings compared to Q1 2024 as cargoes initially scheduled to be lifted during Q4 2024 were pushed into Q1 2025 resulting in 5 cargo liftings in Q1 2025.

BUSINESS UPDATE - CONTINUED

Cost of sales

	Three months ended		Year ended
$'m	**March 31, 2025**	**March 31, 2024**	**December 31, 2024**
Depletion costs	83.4	96.7	372.0
Cost of operations	45.6	37.3	146.1
Movements on overlift/ underlift balances	175.0	(76.2)	(171.2)
Royalties – oil and gas	13.2	19.0	70.2
Others	2.8	3.2	11.1
Total cost of sales	**320.0**	**80.0**	**428.2**

Cost of sales increased in Q1 2025 compared to Q1 2024. The increase in costs of sales is mainly driven by a large overlift movement in Q1 2025 to unwind a large underlift position that existed as per end 2024, compared to an underlift movement in Q1 2024.

Costs of operations increased in Q1 2025 compared to Q1 2024, mainly driven planned maintenance costs and other repairs not incurred in Q1 2024.

Other costs of sales relates to sales costs and the NDDC Levy, which concerns the Niger Delta Development Commission Levy imposed to fund the sustainable development of the Niger Delta region.

Opex/boe

Opex/boe is a non-GAAP measure which represents production costs on a per barrel of oil equivalent basis (using entitlement production). This allows the Company to better analyze performance against prior periods on a comparable basis. The most direct financial statement measure is production costs. Entitlement production is calculated using the economic interest methodology and includes cost oil, profit oil and royalty oil and is different from WI production that is calculated based on project volumes multiplied by the effective WI in each Block.

		Three months ended		Year ended
	Unit	**March 31, 2025**	**March 31, 2024**	**December 31, 2024**
Cost of operations	$'m	45.6	37.3	146.1
Entitlement production	MMboe	3.4	3.6	14.2
Opex/boe	**$/boe**	**13.4**	**10.4**	**10.3**

Opex/boe increased in Q1 2025 compared to Q1 2024 primarily from the higher cost of operations and slightly lower entitlement production.

Entitlement production is used as the denominator as production costs include carry of costs that are recovered through entitlement production.

Cash flow from operations

Cash flow from operations before working capital is a non-GAAP measure. This represents cash generated by removing the impact from working capital from cash generated by operating activities and is a measure commonly used to better understand cash flow from operations across periods on a consistent basis and when viewed in combination with the Company's results provides a more complete understanding of the factors and trends affecting the Company's performance. A reconciliation from cash flow from operations to cash flow from operations before working capital is shown below:

	Three months ended		Year ended
$'m	**March 31, 2025 (1)**	**March 31, 2024 (1)**	**December 31, 2024 (1)**
Cash flow from operations	111.4	n/a	n/a
Working capital adjustments included in cash flow from operations	(11.6)	n/a	n/a
Cash flow from operations before working capital	**99.8**	**n/a**	**n/a**

(1) Cash flow from operations has been reported for the year 2025 only as if the amalgamation had closed on January 1, 2025.

BUSINESS UPDATE - CONTINUED

Free cash flow and Free cash flow/boe [1]

Free cash flow is a non-GAAP measure. This measure represents cash generated after costs, and is a measure commonly used to assess the Company's profitability.

Free cash flow/boe is a non-GAAP ratio which represents free cash flow on a per barrel of oil equivalent basis using entitlement production which allows the Company to better analyze performance against prior periods on a comparable basis. Entitlement production is calculated using the economic interest methodology and includes cost oil, profit oil and royalty oil and is different from WI production that is calculated based on project volumes multiplied by the effective WI in each Block.

A reconciliation from total cash flow (a GAAP measure) to free cash flow (a non-GAAP measure) is shown below:

		Three months ended		Year ended
	Unit	**March 31, 2025** [1]	**March 31, 2024** [1]	**December 31, 2024** [1]
Total cash flow	$'m	(32.5)	n/a	n/a
Add back repurchase of share capital	$'m	8.3	n/a	n/a
Add back debt service costs [2]	$'m	145.8	n/a	n/a
Free cash flow	**$'m**	**121.6**	**n/a**	**n/a**
Entitlement production	MMboe	3.4	n/a	n/a
Free cash flow/boe	**$/boe**	**35.8**	**n/a**	**n/a**

(1) Free cash flow and Free cash flow/boe have been reported for the year 2025 only as if the amalgamation had closed on January 1, 2025.

(2) Debt service costs comprise interest payments, repayments and drawdowns of third-party borrowings.

Tax

The tax expense is made up of the following items:

	Three months ended		Year ended
$'m	**March 31, 2025**	**March 31, 2024**	**December 31, 2024**
Deferred income tax	(34.3)	(16.0)	(80.9)
Education tax	1.5	3.5	14.2
Corporate income tax	26.5	31.3	130.1
Withholding tax on dividends	18.0	-	22.5
Capital gains tax	-	-	33.0
Petroleum Profit Tax	-	-	(2.3)
Other taxes	-	2.4	3.9
Total tax	**11.7**	**21.2**	**120.5**

The tax charge was lower in Q1 2025 compared to Q1 2024 mainly driven by a higher deferred income tax credit following completion of the amalgamation.

Education tax is imposed on every Nigerian company at a rate of 3.0% of the assessable profit in the period.

Petroleum Profit Tax is a tax on the income of companies engaged in upstream petroleum operations in Nigeria. Since operating under the new PSA terms following conversion during 2023, the leases and licenses are no longer subject to PPT.

Other taxes relates to the Naseni (National Agency for Science and Engineering Infrastructure) Levy that is imposed in Nigeria based on 0.25% of profits before tax and the Police Fund Levy that is imposed in Nigeria based on 0.005% of net profit.

BUSINESS UPDATE - CONTINUED

Capital expenditure

Capital expenditure is made up of the following items:

	Three months ended		Year ended
$'m	March 31, 2025 (1)	March 31, 2024 (1)	December 31, 2024 (1)
Nigeria	26.4	n/a	n/a
Equatorial Guinea	1.7	n/a	n/a
South Africa	0.1	n/a	n/a
Total capex	**28.2**	**n/a**	**n/a**

(1) Capital expenditure has been reported for the year 2025 only as if the amalgamation had closed on January 1, 2025.

Capital expenditure in Q1 2025 in Nigeria mainly related to infill drilling on Egina plus some minor facilities costs.

Net Debt

Net Debt is a non-GAAP measure. Net Debt is calculated as loans and borrowings less cash and cash equivalents.

	Three months ended		Year ended
As at/ $'m	March 31, 2025	March 31, 2024	December 31, 2024
Loans and borrowings	620.0	750.0	750.0
Cash and cash equivalents	(428.4)	(464.1)	(460.9)
Net Debt	**191.6**	**285.9**	**289.1**

As at March 31, 2025, the Company has $428.4 million of cash and cash equivalents and $620.0 million of debt (as at December 31, 2024 - $460.9 million of cash and cash equivalents and $750.0 million of debt). During Q1 2025, the Company pro-actively repaid $130.0 million under its RBL facility reducing outstanding debt to $620.0 million.

EBITDAX and Net Debt/EBITDAX

EBITDAX is a non-GAAP measure. This is used as a performance measure to understand the financial performance from the Company's business operations without including the effects of the capital structure, tax rates, DD&A and impairment expenses. A reconciliation from total profit (a GAAP measure) to EBITDAX (a non-GAAP measure) is shown below.

Net Debt/EBITDAX is a non-GAAP measure. Net Debt divided by EBITDAX is a measure of the leverage.

	Three months ended		Twelve months ended
$'m	March 31, 2025 (1)	March 31, 2024 (1)	March 31, 2025 (1)
Total profit/ (loss)	25.9	n/a	n/a
Add back:			
Tax	11.7	n/a	n/a
Finance costs	24.1	n/a	n/a
Finance income	(3.5)	n/a	n/a
Depletion costs	83.4	n/a	n/a
Exploration expenses	-	n/a	n/a
EBITDAX	**141.6**	**n/a**	**n/a**
Net Debt	191.6		
Net Debt/EBITDAX	**0.3**		

(1) EBITDAX and Net Debt/EBITDAX have been reported for the year 2025 only as if the amalgamation had closed on January 1, 2025.

(2) Net debt/EBITDAX has been calculated based on extrapolating Q1 2025 EBITDAX to a full year EBITDAX number.

BUSINESS UPDATE - CONTINUED

Crude Oil Marketing

In considering cargo liftings, the reader should note that the timing and the frequency of these can vary based on a number of factors such as: reservoir performance; actual realized oil price; capex; opex; underlift/overlift positions and marine logistics. The revenue numbers reported include cost oil, profit oil and royalty oil where relevant for each field.

The Group uses a mix of financial derivatives and physical forward sales contracts to manage its commodity price risk and ensure stability in cash flows. Its strategy is to hedge approximately 50-70% of its next 12-months' scheduled cargos.

In most of the Group's oil offtake contracts, the Dated Brent component of the forward price at the time of entering the contract is not fixed but determined on or around the date of the lifting for spot cargos either on an average monthly basis, 5-days after bill of lading date or similar pricing mechanism. If the Group wants to utilize the oil offtake contract for commodity risk management, it can either fix the Dated Brent component or utilize a trigger pricing mechanism. For the trigger pricing mechanism, when the forward price curve falls below a certain trigger price for a certain month, this mechanism provides an irrevocable instruction to an off-taker to fix the Dated Brent price component of a cargo. The trigger price is based on a percentage of the Brent forward curve at the time the instruction was given for the month of the expected lifting. If the forward price curve does not fall below that threshold, the respective cargo is sold at spot.

The average cargo size lifted is one million barrels of oil.

Oil sales were comprised of the following:

		Three months ended		Year ended
Oil Sales	**Unit**	**March 31, 2025**	**March 31, 2024**	**December 31, 2024**
Number of cargo liftings		5	2	9
Of which:				
Sold forward with a fixed Dated Brent		2	-	2
Sold at spot		3	2	7
		5	**2**	**9**
Gross crude oil sales				
Quantity in Mboe	Mboe	4,960.0	2,000.6	9,012.8
Average sales price	$/bbl	79.5	85.5	84.6
Average Bloomberg Dated Brent for the period	$/bbl	75.7	83.1	82.7

Prime sold 5 cargoes during Q1 2025 at an average price of $79.5/bbl with one of these cargoes sold post amalgamation and therefore presented as revenue in the Company's interim condensed consolidated statement of net income and comprehensive income. Of the 7 cargoes expected for the remainder of the year post Q1 2025, 4 cargos had the trigger price mechanism activated in April 2025 at an average price of $64.5/bbl. The remaining 3 cargoes are currently unhedged with no trigger price mechanism in place.

The combination of achieved sales prices in Q1 2025 and future fixed prices have materially de-risked the impact of oil price volatility on the business for 2025. For example, assuming a flat price of $50/bbl Dated Brent across Q2-Q4 2025, the average realized sales price for 2025 will be approximately $67/bbl.

Other non-GAAP measures

This MD&A includes non-GAAP measures, non-GAAP ratios and supplementary financial measures as further described herein. These non-GAAP figures do not have a standardized meaning prescribed by IFRS Accounting Standards and, therefore, may not be comparable with the calculation of similar measures by other companies. The Company believes that the presentation of these non-GAAP figures provides useful information to investors and shareholders as the measures provide increased transparency and the ability to better analyze performance against prior periods on a comparable basis.

Nigeria

Following the amalgamation, the Company has direct interests in three producing fields, three undeveloped discoveries, and number of near-field exploration opportunities in deepwater Nigeria through four PMLs and two PPLs.

The three producing fields are Akpo (PML 2), Egina (PML 3) and Agbami (PML 52). The primary undeveloped oil discovery is Preowei (PML 4), which lies to the north of Egina and Akpo fields and is planned to be developed through a subsea tie-back development to the Egina FPSO. The other two undeveloped discoveries are Egina South (PPL 261), which lies to the southwest of Egina and Akpo fields, and the Ikija discovery (PPL 2003), which lies to the west of Agbami.

The Company's assets are located in the deepwater area of the Niger Delta more than 100 km offshore Nigeria. All three producing fields have high quality reservoirs and produce light to medium sweet crude oil through FPSO facilities. Akpo and Egina also export associated gas which feeds into the Nigerian liquified natural gas plant, whilst Agbami associated gas is mostly reinjected.

BUSINESS UPDATE - CONTINUED

The three fields produce through subsea infrastructure of wells, manifolds and flowlines connected to three purpose built FPSOs. Water injection is used in all fields to maintain reservoir pressure and improve reservoir recoveries, and dedicated water injection wells are positioned to support the producing wells. The produced oil is sold and transported to the international markets directly from the offshore field locations.

The Company has near-field exploration opportunities, including the Akpo Far East prospect, which is located to the east and downdip from the Akpo field on the PML 2 concession area. The trap is defined by dip closure to the south and east, with stratigraphic trapping to the northwest. The reservoir comprises Miocene aged 'G Sands' that form turbiditic deep water fan lobes, equivalent to the G Sands in production in the Akpo main field.

Work is progressing towards the drilling of an exploration well targeting an unrisked, best estimate, gross field prospective resource volume of 143.6 MMboe, at an estimated gross field cost of approximately $50 million.

The key risk for the prospect is up dip stratigraphic seal, which requires an avulsion channel to separate Akpo Far East from the main Akpo field. This sealing facies component may be compromised by a set of later channels that cut across the avulsion channel. Furthermore, the prospect is assumed to hold a hydrocarbon column of approximately 500 m, which is approximately 350 m greater than the column observed for the G Sands in the Akpo field. The prospect is supported by seismic AVO1 analysis with the G Sands in the prospect having a similar seismic response to those in the field and having an apparent cut-off at 4,600m TVDss, which is assumed to be the oil-water-contact.

The targeted hydrocarbons are predicted to be light, high GOR oil equivalent to those found in the Akpo field.

Please refer to pages 19-20 of the Company's Annual Information Form for the Year Ended December 31, 2024, for the detailed commercial information, and pages 41–50 of the same document for the detailed technical information.

Block 3B/4B – South Africa

Africa Oil holds an 18.0% interest in Block 3B/4B following the completion of the agreement with Eco to acquire an additional 1.0% (one percent) interest from Azinam Limited, Eco's wholly owned subsidiary, in exchange for all common shares and warrants held by the Company in Eco. Africa Oil will continue to benefit from the carry agreed between Eco, TotalEnergies and QatarEnergy prior to the transfer of the interest to Africa Oil.

On August 28, 2024, the Company announced the completion of the strategic farm down agreement with TotalEnergies and QatarEnergy. The Company retained a direct 17.0% (increased to 18.0% in Q1 2025) non-operated interest in the block and operatorship was transferred to TotalEnergies.

Transaction highlights are:

- Maximum transaction value of up to $46.8 million to the Company.
- The Company will receive, subject to achieving certain milestones defined in the farm down agreement, staged payments for a total cash amount of $10.0 million, of which $3.3 million was received at completion with the remaining balance to be received in two successive payments conditional upon achieving key operational and regulatory milestones.
- The Company will also receive a full carry of its retained share of all JV costs, up to a cap, that is repayable to TotalEnergies and QatarEnergy from production, and which is expected to be adequate to fund the Company's share of drilling for 1-2 wells on the license.

The Company expects that the first exploration well on Block 3B/4B can be drilled during 2026.

Blocks EG-18 and EG-31 – Equatorial Guinea

The Company, through wholly-owned subsidiaries, holds an operated WI of 80.0% in each of Blocks EG-18 and EG-31, offshore Equatorial Guinea. GEPetrol, the national oil company of Equatorial Guinea, holds the balance in each block and is carried during the exploration phase. Work programs on both Blocks include re-processing of existing 3D seismic surveys and identification of prospects within the first 2-year sub period. A 1-year extension of the first Exploration sub-period was granted on December 23, 2024, extending the renewal period to March 1, 2026. At the end of Q1 2025, all financial commitments for the initial exploration period have been met, the 1-year extension should enable the required technical work to be completed.

These blocks present two distinct exploration strategies with EG-31 being infrastructure-led, targeting natural gas prospects in proximity to gas transportation, processing and export infrastructure, and EG-18 being a frontier exploration play targeting a deepwater oil prospect with multi-billion barrel potential.

BUSINESS UPDATE - CONTINUED

Equity Investments in Associates

As at March 31, 2025, the Company held equity investments in two oil and gas companies, which provides exposure to several high-impact exploration drilling prospects in South Africa and Namibia.

The Company held the following equity investments in associates as of March 31, 2025:

	Africa Energy	Impact (1)
Issued and Outstanding	2,395,812,249	1,139,147,442
Shares held by AOC at December 31, 2024	276,982,414	449,464,396
Shares acquired in the period	-	-
Shares held by AOC at March 31, 2025	276,982,414	449,464,396
AOC's holding (%) – March 31, 2025	11.56%	39.46%
AOC's holding (%) – December 31 2024	19.67%	39.46%
Share price (CAD) on March 31, 2025	0.04	-
Exchange rate to USD on March 31, 2025	0.70	-

(1) Impact is a privately held UK company and no share price is available.

Impact

The Company through its 39.5% shareholding in Impact Oil & Gas Limited has an effective 3.8% interest in Blocks 2912 and 2913B, offshore Namibia, with the latter block containing the Venus light oil discovery. The blocks are operated by a subsidiary of TotalEnergies. Impact is a private UK oil and gas exploration company with assets located offshore Namibia and South Africa.

In 2024, the Company acquired an additional 105.9 million shares in Impact for $88.6 million, across two transactions, increasing its interest from 31.1% to 39.5%. This enhances the Company's strategic position, rights and influence over a core asset and value driver for the Company.

On November 1, 2024, the Company announced the completion of a strategic farm-down agreement between its investee company, Impact, and TotalEnergies. Following the closing of this deal, Impact retains a 9.5% interest in the Blocks that is fully carried for all joint venture costs, with no cap, through to first commercial production. Impact also received a cash reimbursement of approximately $99.2 million for its share of the past costs incurred on the Blocks net to the farmout interest. Following this, in Q1 2025 the Company received a distribution of $31.6 million from Impact.

This agreement provides Impact with a full interest-free carry loan over all of Impact's remaining development, appraisal and exploration costs on the Blocks from January 1, 2024 ("Effective Date"), until the date on which Impact receives the first sales proceeds from oil production on the Blocks ("First Oil Date").

On and from the First Oil Date, the carry is repayable to TotalEnergies in kind from 60% of Impact's after-tax cash flow net of all joint venture costs, including capital expenditures. During the repayment of the carry, Impact will pool its entitlement barrels with those of TotalEnergies for more regular off-takes and a more stable cashflow profile and will also benefit from TotalEnergies' marketing and sales capabilities.

Since the initial Venus-1X oil discovery in February 2022, four appraisal wells have been drilled to assess the Venus Field in Block 2913B, offshore Namibia. Development studies are ongoing, with a final investment decision targeted by mid-2026. The Venus Field is expected to produce approximately 150 kbopd of ~45° API oil.

Also in 2024, two additional 3D seismic surveys were completed across the blocks, resulting in most of the licensed area now being covered. This data is currently being processed and interpreted and will help further evaluate prospects and leads in the far northern and southern parts of the Blocks.

During Q1 2025, the joint venture completed the drilling of Tamboti-1X exploration well in Block 2913B. Tamboti-1X was safely and successfully drilled to a total depth of 6,450mMD on Block 2913B, approximately 12km northeast of the Mangetti-1X well and approximately 25km north-northwest of the Venus-2A well, using the Deepsea Mira semi-submersible drilling rig. Black oil was encountered within 85m of net reservoir of lower quality Upper Cretaceous sandstones, belonging to the Mangetti fan system. A DST program was completed at the Tamboti-1X location, and results from the acquired log, core and DST data are currently under analysis.

On April 28, 2025, the Company announced the result of the Marula-1X exploration well on Block 2913B. The well was safely drilled to a total depth of 6,460m (measured depth) on block 2913B, targeting Albian aged sandstones, within the Marula fan complex, approximately 47 Km south of the Venus-1X well, using the Deepsea Mira semi-submersible drilling rig. No hydrocarbons were encountered in the primary target in the Marula-1X well and no Drill Stem Test was performed. A comprehensive analysis of the well results is now underway.

BUSINESS UPDATE - CONTINUED

Africa Energy

Africa Energy is a TSX-Venture (Toronto) and Nasdaq First North Growth Market (Stockholm) listed international oil and gas exploration company with an interest in Block 11B/12B offshore South Africa. There are two gas condensate discoveries (Brulpadda and Luiperd) on this block in proximity to offshore gas infrastructure and onshore gas market in Mossel Bay, South Africa.

On July 1, 2024, Africa Energy announced that CNR International (South Africa) Limited, a partner in Block 11B/12B, has provided notice to the joint venture partners that it will withdraw from its 20% interest in the Block. On July 29, 2024, TotalEnergies EP South Africa B.V., the operating partner on the Block, and QatarEnergy International E&P LLC announced that they will withdraw from their 45% and 25% operated interests in the Block, respectively. Under the joint operating agreement, the withdrawing parties will assign their interest free of charge to Main Street 1549 Proprietary Ltd. ("Main Street"), the non-withdrawing partner, which currently has a direct 10% participating interest in Block 11B/12B.

Africa Energy owns 49% of the common shares and 100% of the Class B shares of Main Street. The remaining 51% of the common shares of Main Street are held by Arostyle. In light of the withdrawal of the joint venture partners in Block 11B/12B, and subject to all relevant regulatory approvals, Main Street expects to hold a 100% participating interest in Block 11B/12B.

On December 20, 2024, Africa Energy announced that it has entered into a non-binding agreement with Arostyle Investments (RF) Proprietary Ltd. ("Arostyle"), to restructure their joint investment in Main Street. Under the non-binding agreement, Africa Energy and Arostyle agreed that subject to all relevant regulatory approvals, the Parties will restructure Main Street resulting in the Company holding a direct 75% participating interest and Arostyle holding a direct 25% participating interest in Block 11B/12B, with the relationship between the Parties being governed by the existing Joint Operating Agreement in respect to Block 11B/12B.

Africa Energy and Arostyle believe that natural gas will play a critical role in South Africa's energy transition, and the use of indigenous gas from Block 11B/12B discoveries are currently the most material domestic supply option in South Africa.

On March 31, 2025, Africa Energy announced the closing of a private placement of common shares, including the issue of common shares for debt. Africa Oil did not participate in this private placement and as a result its shareholding in Africa Energy has been reduced from 19.67% as at December 31, 2024, to 11.56% as at the date hereof. Some of the proceeds from the private placement were used to repay Africa Oil's debt of approximately $4.5 million.

ENVIRONMENTAL, SOCIAL AND GOVERNANCE

The Company is committed to operating in a responsible manner that integrates sustainability considerations throughout its decision-making and operational management, to support Company commercial objectives. The Company is focused on the effective identification and management of risk in its operational activities and, to the extent that it is reasonably able to influence them, those of its JV parties and investee companies. The Company selects its operating parties in part on their ability and commitment to manage ESG risks effectively. The Company monitors operator performance and works with operators where possible and necessary to improve performance. The Company's role as the custodian of its shareholders' capital is to ensure robust governance systems are in place to minimize risks and deliver our sustainability goals.

As part of those governance systems, the Company receives operator ESG performance data from Nigeria on a quarterly basis, which allows it to monitor alignment with agreed ESG targets and objectives. Prior to the amalgamation, at the Company's request, Prime developed an updated ESG Strategy and GHG Roadmap in 2024, focused on compliance with IFC Performance Standards, a long term plan for net zero Scope 1 and 2 GHG emissions by 2050 and zero routine flaring by 2030. The Company will continue to implement this plan.

Reductions in flaring and fugitive emissions will support the Company's objectives to reduce working interest scope 1 greenhouse gas ("GHG") emissions by 25% by 2025 and by 35% by 2030 compared to a 2020 baseline as part of Prime's Net Zero by 2050 for scope 1 and 2 emissions.

Additionally, the Company will continue Prime's engagement of independent Environmental, Social, Health and Safety ("ESHS") monitoring reviews conducted annually to support the Company's reserves-based lending facility. The 2024 Monitoring Review found that overall, Prime was managing the ESHS aspects of its business, in its non-operated role, "exceptionally well," with no significant issues that would impact financing. A 2025 monitoring review for the Company is currently being undertaken.

The Company has completed an environmental and social impact assessment to support permitting and licensing to support exploration drilling activities in Block 3B/4B in South Africa. The Company submitted an ESIA application for proposed drilling activities on Block 3B/4B during Q2 2024. An Environmental Authorization was issued by the regulator in September 2024 and that is being followed by a stakeholder consultation and appeals process which concluded in December 2024. Operatorship has been transferred to TEEPSA. The regulator is expected to provide its final decision on the appeals during mid-2025.

As part of its compliance with its PSC requirements in Equatorial Guinea and in line with the Company's Social Investment Framework, the Company has funded the renovation of a school at Ayene in mainland Equatorial Guinea. In addition to the PSC requirements, Africa Oil funded school supplies for all students and classrooms at the recently renovated school.

For the Venus project in Namibia, the Operator has completed geophysical and geotechnical surveys and has commenced the development of an ESIA to support permit approvals for the construction and operation of the project. A draft Scoping Report for the Venus Project in Namibia has been issued on behalf of the Operator, the final version which will be submitted to the Ministry of Mines and Energy: Directorate of Petroleum Affairs (MME) for review. The recommendation of the MME will be submitted to the Ministry of Environment, Forestry and Tourism: Directorate of Environmental Affairs (MEFT) for final decision-making and acceptance.

The Company's environmental and social management system, which is overseen by the Board-level Sustainability Committee, aims effectively and appropriately to identify, monitor and address environmental, health & safety and social risks to our business and investments, in addition to identifying opportunities for performance improvement and risk reduction. The Company maintains a risk register by which it monitors financial, operational and ESG risks to the Company. Africa Oil regularly undertakes annual independent HSEC audits and engages with a range of ESG ratings assessments in support of investor and broader stakeholder engagement, as well as to identify opportunities for performance improvement.

Africa Oil is committed to regular review and update of its sustainability strategy to ensure continued alignment with both the Company's evolving business and the broader global context.

The Company was awarded a silver rating by the ESG rating agency EcoVadis in April 2025. The independent evaluation undertaken concluded that the Company was within the top 10% of all companies evaluated for ESG performance.

To the extent possible given its non-Operator role on assets, the Company endeavors to undertake its activities in line with the IFC's Performance Standards on Environmental and Social Sustainability and independent monitoring reviews are conducted on a regular basis to assess compliance with those standards. The most recent review was completed in December 2024. This found that Company management systems were fit for purpose to manage ESG risks. The report is published, along with all other Independent Monitoring Group reports, on Africa Oil's website.

The Company's 2024 Sustainability Report, published on May 12, 2025, is disclosed on the Company website, as in previous reports it contains more detailed information on our performance and strategy.

On an ongoing basis, the Company monitors the development of applicable legislation to ensure compliance with evolving policy and associated regulatory requirements. As the Company has a primary listing in Canada on the Toronto Stock Exchange and a secondary listing in Sweden on the Oslo Stock Exchange, this includes sustainability disclosure requirements in both Canada and the EU, including the EU Corporate Sustainability Reporting Directive (CSRD). The Company takes note of recent proposals by the EU to reduce significantly the reporting requirements under CSRD.

SUMMARY OF QUARTERLY INFORMATION

All financial information included in the narrative discussion below is based on the consolidated statement of net income and comprehensive income and considers the amalgamation closing on March 19, 2025.

Summarized quarterly results for the past eight quarters are as follows:

For the three months ended	31-Mar 2025	31-Dec 2024	30-Sep 2024	30-Jun 2024	31-Mar 2024	31-Dec 2023	30-Sep 2023	30-Jun 2023
Revenue	76.4	-	-	-	-	-	-	-
Net income/ (loss) attributable to common shareholders ($'m)	50.9	6.2	(289.2)	0.4	3.5	(88.8)	47.1	106.9
Weighted average shares – Basic '000	468,472	442,690	442,960	451,231	460,991	462,231	462,340	456,229
Weighted average shares – Diluted '000	476,836	449,667	442,960	464,890	474,746	472,942	473,959	467,839
Basic income / (loss) per share ($)	0.11	0.02	(0.65)	0.00	0.01	(0.19)	0.10	0.23
Diluted income/ (loss) per share ($)	0.11	0.02	(0.65)	0.00	0.01	(0.19)	0.10	0.23

SUMMARY OF KEY ITEMS OF FINANCIAL PERFORMANCE IN THE THREE MONTHS ENDED MARCH 31, 2025, AND MARCH 31, 2024

	Three months ended	
	March 31, 2025	March 31, 2024
Revenue	76.4	-
Gross Profit	13.1	-
General and administrative expenses	(13.5)	(5.1)
Net income	50.9	3.5
Adjusted net income	10.0	17.8

SUMMARY OF QUARTERLY INFORMATION - CONTINUED

Revenue

Revenue generated in Q1 2025 was $76.4 million (Q1 2024 – nil) and relates to 1 cargo sold post amalgamation at a price of $74.2/bbl. Prior to the closing of the amalgamation on March 19, 2025, the Company did not report any revenue in its consolidated statement of net income and comprehensive income.

Gross profit

Gross profit reported in Q1 2025 was $13.1 million (Q1 2024 – nil). Gross profit was impacted by costs of sales in Q1 2025 of $63.3 million (Q1 2024 – nil) and mainly comprised of depletion costs of $12.1 million, movements on overlift/underlift balances of $41.9 million and costs of operations of $7.4 million.

General and administrative costs

On March 19, 2025, the Company announced the completion of the amalgamation to acquire the remaining 50% interest in Prime in exchange for 239,828,655 newly issued common shares in Africa Oil. This transaction falls under IFRS 3 under which acquisition related costs are expensed in the periods in which the costs are incurred, and the services are received.

The table below shows adjusted general and administrative expenses, which is a non-GAAP measure, by excluding the BTG Oil & Gas transaction related expenses and is meant to improve comparability between periods. The BTG Oil & Gas transaction related expenses also include certain LTIP charges for fully vested LTIP units as a result of the closing of the amalgamation.

	Three months ended	
	March 31, 2025	**March 31, 2024**
General and administrative expenses	13.5	5.1
BTG Oil & Gas transaction related expenses	(7.6)	(0.3)
Adjusted general and administrative expenses	5.9	4.8

Adjusted general and administrative expenses, including share-based compensation charges relating to the LTIP and Stock Option Plan that are not impacted by the closing of the amalgamation, amounted to $5.9 million in Q1 2025 (Q1 2024 - $4.8 million). Share-based compensation charges not impacted by the closing of the amalgamation amounted to $1.2 million in Q1 2025 (Q1 2024 – $0.5 million) are impacted by movements in the share price of the Company.

Adjusted general and administrative expenses excluding share-based compensation charges have stayed fairly consistent when comparing the periods and amounted to $4.7 million in Q1 2025 compared to $4.3 million in Q1 2024.

Net income/ (loss) and Adjusted net income/ (loss)

Net income as reported by the Company in its Interim Condensed Consolidated Statement of Net Income and Comprehensive Income can be impacted by items that are not reflective of the Company's underlying performance for the period. This might impact the comparability of the results of the Company between periods.

Adjusted net income/ (loss) is a non-GAAP measure. This measure adjusts for the following items and is meant to improve comparability between periods:

- Impairment and reversal of impairment is adjusted since this affects the economics of an asset for the lifetime of that asset, not only the period in which it is impaired, or the impairment is reversed.
- Share of loss from investments in associates is adjusted since the associated companies are in the exploration phase with the results not being reflective of the Company's underlying performance for the period.
- Other items of income and expenses are adjusted when the impact on net income in the period is not reflective of the Company's underlying performance for the period.
- Tax effects of the above-mentioned adjustments to net income.

SUMMARY OF QUARTERLY INFORMATION - CONTINUED

A reconciliation from net income/ (loss) to adjusted net income/ (loss) is shown below:

		Three months ended		Years ended
	Unit	March 31, 2025	March 31, 2024	December 31, 2024
Net income/ (loss)	**$'m**	**50.9**	**3.5**	**(279.1)**
Adjusted for:				
Income recognized by Prime under Securitization Agreement – net to AOC's shareholding	$m	-	-	(164.8)
Tax effect of income recognized by Prime under Securitization Agreement – net to AOC's shareholding	$m	-	-	16.5
(Reversal of impairment)/ impairment investment in Prime	$'m	(42.9)	-	436.7
Share of loss from investments in associates	$'m	2.0	14.3	38.7
Adjusted net income	**$'m**	**10.0**	**17.8**	**48.0**
Adjusted net (loss)/ income attributable to common shareholders per share				
Basic		0.02	0.04	0.11
Diluted		0.02	0.04	0.11
Weighted average number of shares outstanding for the purpose of calculating adjusted net income per share				
Basic		468,472,433	460,990,598	449,431,803
Diluted		476,836,682	474,745,624	456,462,277

Net income amounted to $50.9 million in Q1 2025 (Q1 2024 - $3.5 million). Net income has increased as an impairment reversal of $42.9 million was recognized in relation to the investment in Prime during Q1 2025. Prime has been fully consolidated from closing date of the amalgamation, March 19, 2025.

Adjusted net income amounted to $10.0 million in Q1 2025 (Q1 2024 - $17.8 million). Adjusted net income in Q1 2025 is lower compared to adjusted net income in Q1 2024, mainly driven by higher general and administrative expenses in Q1 2025 relating to the transaction with BTG Oil & Gas to acquire the remaining 50% interest in Prime.

SUMMARY OF KEY ITEMS OF FINANCIAL POSITION AS AT MARCH 31, 2025, AND DECEMBER 31, 2024

As at	March 31, 2025	December 31, 2024
Assets		
Oil and gas properties	1,588.8	-
Intangible exploration assets	39.0	29.3
Equity investments in associates	143.1	177.6
Trade receivables	156.2	-
Cash and cash equivalents	428.4	61.4
Outstanding bank debt	620.0	-

SUMMARY OF QUARTERLY INFORMATION - CONTINUED

Oil and gas properties

Oil and gas properties have increased following closing of the amalgamation to acquire the remaining 50% interest in Prime following which Prime is fully consolidated by the Company.

As at March 31, 2025, oil and gas properties amounted to $1,588.8 million (as at December 31, 2024 – nil) and related to the licenses PML 52 (covering part of the Agbami field), PML 2 (Akpo field), PML 3 (Egina field) and PML 4 (Preowei Field) in Nigeria.

Intangible exploration assets:

As at March 31, 2025, the carrying amount of the Company's intangible exploration assets in Equatorial Guinea was $19.6 million (as at December 31, 2024 – $17.9 million) and related to its 80% interest in Blocks EG-18 and EG-31.

As at March 31, 2025, the carrying amount of the Company's intangible exploration assets in South Africa was $19.4 million Right (as at December 31, 2024 - $11.4 million) and related to its 18.0% (as at December 31, 2024 – 17.0%) participating interest in the Block 3B/4B Exploration Right.

Equity investments in associates

As at March 31, 2025, the Company's investment in associates was $143.1 million compared to an investment value of $177.6 million as at December 31, 2024. The carrying value of the investments decreased by $34.5 million in Q1 2025 from the Company's share of the associates losses of $2.9 million in combination with a distribution by Impact of $31.6 million net to the Company's shareholding. The investment in Impact, holding the working interests in the Namibia Orange Basin Blocks 2913B and 2912, makes up $141.6 million of the total equity investments in associates.

Trade receivables

Trade receivables have increased following closing of the amalgamation to acquire the remaining 50% interest in Prime following which Prime is fully consolidated by the Company. Trade receivables relates to two cargo sales during March with the amounts received during April.

Cash and cash equivalents

Cash and cash equivalents have increased following closing of the amalgamation to acquire the remaining 50% interest in Prime following which Prime is fully consolidated by the Company. As at March 31, 2025, the Company had $428.4 million cash and cash equivalents on hand, compared to a cash balance of $61.4 million as at December 31, 2024. The Company acquired cash balances on closing date of the amalgamation of $380.4 million, the Company received a distribution from Prime of $60.0 million prior to the closing of the amalgamation, repaid $130.0 million of the RBL facility, returned $8.3 million to shareholders by way of share buybacks, received a distribution from Impact of $31.6 million, incurred capital and operational expenditure in respect of the licenses in Nigeria, Equatorial Guinea and South Africa, settled working capital balances and incurred general and administrative costs.

Outstanding bank debt

Outstanding bank debt increased following closing of the amalgamation to acquire the remaining 50% interest in Prime following which Prime is fully consolidated by the Company. Subsequent to closing of the amalgamation, the Company pro-actively repaid $130.0 million under the RBL facility, reducing outstanding bank debt to $620.0 million as at March 31, 2025.

LIQUIDITY AND CAPITAL RESOURCES

As at March 31, 2025, the Company had cash balances of $428.4 million and working capital balances (including cash balances) of $201.4 million, calculated as current assets less current liabilities as presented in the interim condensed consolidated balance sheet as per March 31, 2025. The Company's primary source of liquidity is operating income in Nigeria and the remaining undrawn amounts on the RBL and Corporate Facilities.

Reserves Based Lending Facility

On amalgamation the Company acquired a Reserves Based Lending Facility ("RBL"). The total amount that can be drawn under the RBL is limited to the Borrowing Base Amount ("BBA"), which is subject to redeterminations on March 31 and September 31 of each year, limited by aggregate commitments. As of March 31, 2025, the BBA was $720.0 million, which will amortize as the RBL moves towards final maturity.

The principal bears interest at Term SOFR + 4.00% until June 2025, then Term SOFR + 4.25% until June 2027, then Term SOFR + 4.50% until final maturity on June 20, 2029. In addition, commitment fees of 40% of the margin are payable on the undrawn but available portion of the RBL, and commitment fees of 20% of the margin are payable on the unavailable portion of the RBL.

The RBL perimeter remains at the Prime level - Prime is the borrower, and Prime 127 Nigeria Limited and Prime 130 Nigeria Limited are the guarantors. The main security package is comprised of security over the shares, production assets, contracts and rights of the Nigerian entities - Prime 127 and Prime 130. In addition, RBL lenders have security over cash and cash equivalents held in project accounts, receivables against cargos sold and all relevant insurance policies of the three Prime entities.

All financial and liquidity covenants covered the RBL are restricted to these three entities. The Prime entities shall ensure that total net debt to adjusted EBITDAX on each quarter is no greater than 3.0:1, that the historic debt service cover ratio for the preceding year is greater than 1.20:1, and that on each quarter of each year during each of the four successive quarters there are or will be sufficient funds available to the group to meet all relevant expenditure to be incurred in each of these four successive quarters as they fall due. The Company has been in compliance with the covenants in the three months ended March 31, 2025.

Corporate Facility

On May 21, 2024, the Company amended its existing Corporate Facility. At any point before Prime refinances its debt, the availability under the Corporate Facility will now be $65.0 million until June 30, 2025, $43.0 million from July 1, 2025, until June 30, 2026, and $22.0 million from July 1, 2026, to May 21, 2027, i.e. its new final maturity date. After Prime refinances its debt, the availability under the Corporate Facility will be $125.0 million until June 30, 2026, and $63.0 million from July 1, 2026, until May 21, 2027. Commitment fees of 40% of the margin are payable on the undrawn available portion of the Corporate Facility and commitment fees of 15% of the margin are payable on the unavailable portion of the Corporate Facility. The Corporate Facility carries interest of 1 month-SOFR plus a margin of 6.5% in the first year from May 21, 2024, 7.0% in the second year and 7.5% in the third year.

The Company provided security in respect of the Corporate Facility mainly in the form of a share pledge over the shares of PetroVida (which holds 50% of Prime), and a charge over the bank account into which the Prime distributions are paid.

The Corporate Facility is subject to financial and liquidity covenants. The Company shall ensure that total net debt to adjusted EBITDAX on June 30 and December 31 of each year is no greater than 3.0:1, the FLCR ratio on March 31 and September 30 of each year is not less than 1.1:1 and that from March 31 and September 30 of each year during each of the four successive quarters there are or will be sufficient funds available to the group to meet all relevant expenditure to be incurred in each of these four successive quarters as they fall due. The Company has been in compliance with the covenants in the three months ended March 31, 2025.

Post end of 1Q 2025, the Company has commenced the process to cancel its $65.0 million Corporate Facility, which remains undrawn.

Future Funding Outlook

To finance its future acquisition, exploration, development and operating costs, the Company may require financing from external sources, including issuance of new shares, issuance of debt or executing farmout 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.

The Company believes that its existing cash balances combined with anticipated funds flow from its operations and undrawn facilities will provide sufficient liquidity for the Company to meet its financing, operating and capex commitments as they fall due.

OUTSTANDING SHARE DATA

The following table outlines the maximum potential impact of share dilution upon full execution of outstanding convertible instruments as at the effective date of the MD&A.

Common shares outstanding	675,436,334
Outstanding share purchase options	457,616
Outstanding restricted share units	645,507
Outstanding performance share units	6,227,320
Full dilution impact on Common Shares outstanding	682,766,777

RELATED PARTY TRANSACTIONS

Transactions with Africa Energy:

On December 19, 2022, Africa Energy announced that it had secured a $5.0 million promissory note of which $2.0 million was provided by the Company and the remaining by other parties. On November 7, 2023, the promissory note provided by the Company and other parties to Africa Energy was increased by $3.3 million with $1.5 million of the increase provided by the Company by the end of the year ended December 31, 2024. No funds were provided in the three months ended March 31, 2025, and $0.3 million was provided in the three months ended March 31, 2024. The note was unsecured and matured on March 31, 2025, when the principal and accrued interest was repaid by Africa Energy in full. The note carried an annual interest rate of 15%. In the three months ended March 31, 2025, interest on the note amounted to $0.2 million (three months ended March 31, 2024 - $0.1 million).

Transactions with Eco:

On July 26, 2024, the Company signed an agreement with Eco to acquire an additional 1.0% interest in Block 3B/4B from Azinam Limited, Eco's wholly owned subsidiary, in exchange for all common shares and warrants over common shares held by the Company in Eco. On January 13, 2025, the Company announced that it had completed this transaction. The Company's interest in Block 3B/4B increased by 1.0% to 18.0% and the Company ceased to be a shareholder in Eco. Africa Oil will benefit from the carry agreed between Eco, TotalEnergies and QatarEnergy for this incremental interest.

Transactions with Impact:

On January 29, 2025, Impact distributed $31.6 million net to the Company's shareholding.

Transactions with BTG Oil & Gas:

The Company has recorded an indemnity asset of $21.6 million recognized under the deed of indemnity entered into between a subsidiary of the Company and BTG Oil & Gas (see note 13 of the financial statements).

COMMITMENTS AND CONTINGENCIES

The following commitments and contingencies are representative of the Company's net obligations at the effective date of the MD&A.

PRIME OIL & GAS COÖPERATIEF U.A:

Under the Prime Sale and Purchase Agreement completed on January 14, 2020, a deferred payment of $118.0 million, subject to adjustment, may be due to the seller contingent upon the timing of the final PML 52 tract participation in the Agbami field. The signing of the Securitization Agreement by Prime in 2021 led to the Company reassessing its view of the likelihood of making a contingent consideration payment to the seller. The signing of the Securitization Agreement by Prime does not constitute a redetermination of the tract participation and therefore does not trigger the payment of a contingent consideration under the Sale and Purchase Agreement but, at the Company's discretion, could trigger discussions with the seller. The outcome of this process is uncertain. In 2021, the Company recorded $32.0 million as contingent consideration and increased this to $40.4 million as at December 31, 2024, and to $41.1 million in the three months ended March 31, 2025.

WITHDRAWAL FROM KENYA:

On May 23, 2023, the Kenya entities along with TotalEnergies submitted withdrawal notices to the remaining joint venture party on Blocks 10BB, 13T and 10BA in Kenya, to unconditionally and irrevocably, withdraw from the entirety of the JOAs and PSCs for these concessions. The Company concurrently submitted notices to Ministry of Energy and Petroleum, requesting the government's consent to transfer all of its rights and future obligations under the PSCs to its remaining joint venture party. Government consent to the transfer remained outstanding as at March 31, 2025. In accordance with the JOA and PSC the Company retains economic participation for activities prior to June 30, 2023, which might result in additional costs for the Company. The Company continues to monitor the claim made against the operator by local communities in relation to past operations which may relate to the period prior to June 30, 2023. No provision has been recognized for this as at March 31, 2025.

CRITICAL ACCOUNTING ESTIMATES - CONTINUED

SECURITIES AND GUARANTEES:

Under the conditions of the RBL facility, the main security package is comprised of security over the shares, production assets, contracts and rights of the Nigerian entities Prime 127 and Prime 130, cash and cash equivalents in the amount of $234.7 million as per March 31, 2025, that are held within the projects accounts in Nigeria and The Netherlands, proceeds from the oil cargos sold and proceeds from the intercompany receivables between the Company and the Nigerian entities. Further, any and all claims relating to, and all returns of premium in respect of, all relevant insurance policies have been secured.

COMMITMENTS FROM FORWARD SALES:

The Group uses a mix of financial derivatives and physical forward sales contracts to manage its commodity price risk and ensure stability in cash flows. Its strategy is to hedge approximately 50-70% of its next 12-months' scheduled cargos. As at March 31, 2025, four cargos of the Group's expected lifted entitlement production for the remainder of 2025 are covered by forward contracts. The average cargo lifted is for 1 million barrels of oil. The Group's triggers for the four cargos covered by forward contracts have been triggered in April 2025 at an average of $64 per barrel.

CRITICAL ACCOUNTING ESTIMATES

The Company's critical accounting estimates are defined as those estimates that have a significant impact on the portrayal of its financial position and operations and that require management to make judgements, assumptions and estimates in the application of IFRS Accounting Standards. Judgements, assumptions and estimates are based on historical experience and other factors that management believes to be reasonable under current conditions. As events occur and additional information is obtained, these judgements, assumptions and estimates may be subject to change.

USE OF ESTIMATES

The preparation of the consolidated financial statements in conformity with IFRS Accounting Standards requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the reporting period. Such estimates include unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from these estimated amounts as future confirming events occur. Significant estimates used in the preparation of the consolidated financial statements include, but are not limited to, recovery of exploration costs capitalized in accordance with IFRS Accounting Standards, equity method accounting, valuation and impairment of equity investments and contingent consideration arising from the acquisition of Prime.

The Company' material accounting policies can be found in the Company's audited consolidated financial statements for the year ended December 31, 2024, and in the Company's unaudited interim condensed consolidated financial statements for the three months ended March 31, 2025

OIL AND GAS PROPERTIES

The Company capitalizes costs related to the acquisition of a license interest, directly attributable general and administrative costs, expenditures incurred in the process of determining oil and gas exploration targets, and exploration drilling costs. All exploration expenditures that related to properties with common geological structures and with shared infrastructure are accumulated together within non-producing oil and gas properties. Costs are held un-depleted until such time as the exploration phases on the license area are complete or commercially viable reserves have been discovered and extraction of those reserves is determined to be technically feasible. The determination that a discovery is commercially viable, and extraction is technically feasible requires judgement.

Where results of exploration drilling indicate the presence of hydrocarbons which are ultimately not considered commercially viable, all related costs are recognized in the Consolidated Statement of Net Income and Comprehensive Income. If commercial reserves are established and technical feasibility for extraction demonstrated, then the related capitalized non-producing oil and gas properties are transferred into the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (CGU) within producing oil and gas properties. The allocation of the Company's assets into CGUs requires judgement.

Non-producing oil and gas properties are assessed for impairment when they are reclassified to producing oil and gas properties, and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to dispose. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proven and probable reserves. In determining fair value less costs to dispose, recent market transactions are taken into account, if available. In the absence of such transactions, an appropriate valuation model is used.

The key assumptions the Company uses for estimating future cash flows are the quantity of contingent resources, future commodity prices, expected production volumes, future operating and development costs, likelihood of a successful farm out process and subsequent timing of FID and discount rate. The estimated useful life of the CGU, the timing of future cash flows and discount rates are also important assumptions made by management.

CRITICAL ACCOUNTING ESTIMATES - CONTINUED

The changing worldwide demand for energy and the global advancement of alternative sources of energy could result in a change in the assumptions used to determine the recoverable amount and could affect estimating the future cash flows which could impact carrying amount of the Company's intangible exploration assets. The timing of when global energy markets transition from carbon-based sources to alternative energy sources is highly uncertain. Environmental considerations are built into our estimates through the use of key assumptions in estimating fair value including future commodity prices and discount rates. The energy transition could impact the future prices of commodities and discount rates used to appraise oil and gas projects. Pricing assumptions used in the determination of recoverable amounts incorporate markets expectations and the evolving worldwide demand for energy.

EQUITY METHOD

Investments in joint ventures and investments in associates are accounted for using the equity method. Investments of this nature are recorded at original cost. Investments in joint ventures or associates which arise from a loss in control of a subsidiary are recorded at fair value on the date of the loss of control. The investment is adjusted periodically for the Company's share of the profit or loss of the investment after the date of acquisition. The investor's share of the profit or loss of the investee is also recognized in the Company's Consolidated Statement of Net Income and Comprehensive Income. Distributions received reduce the carrying amount of the investment.

IMPAIRMENT OR REVERSAL OF IMPAIRMENT OF JOINT VENTURES AND ASSOCIATES

The amounts for investments in joint ventures and associates represent the Company's equity interest in other entities, where there is either joint control or significant influence. The Company assesses investments in joint ventures and associates for an objective evidence of impairment or reversal of impairment considering changes in circumstances or events which indicate that the carrying value may not be recoverable or that the carrying value is below the fair value. The process of determining whether there is an objective evidence of impairment or reversal of impairment or calculating the recoverable amount requires judgement.

CONTINGENT CONSIDERATION

Contingent consideration formed part of the overall consideration for the acquisition of Prime. At the date of acquisition, an estimate of the contingent consideration is determined and included as part of the cost of the acquisition.

Subsequent to acquisition, contingent consideration can be treated using two acceptable methods, the cost-based approach and the fair value-based approach. The Company have determined the cost-based approach to give the best estimate of the value of the contingent consideration. Any revisions to the contingent consideration estimates, after the date of acquisition, are accounted for as changes in estimates in accordance with IAS 8, to be accounted for on a prospective basis. The change in the liability, as a result of the revised cash flows, would be adjusted to the cost of the investment and, in accordance with paragraph 37 of IAS 8, recognized as part of the investment's carrying amount rather than in profit or loss.

The estimates involved in assessing the value of the contingent consideration include the expected timing of payments, the expected settlement value, the likelihood of settlement and the probability of the assessed outcomes occurring. There is significant judgement used in the determination of these estimates.

CLASSIFICATION OF JOINT ARRANGEMENTS

The Group is a party to transactions of non-operated Production Sharing Agreements ("PSAs"). The PSA transactions include the Group's proportionate share of the PSAs assets, liabilities and expenses, with items of a similar nature on a line-by-line basis, from the date that participation in the PSA arrangements commenced.

The Group has applied judgment in determining that it has joint control over the PSAs. This determination recognizes that all major decisions outside the original scope of the operations require unanimous approval by at least the Group and one or more of the PSAs partners.

The Group has determined that the relevant activities for its joint arrangements are those relating to the operating and capital decisions of the arrangement, such as approval of the capital expenditure program for each year and appointing, remunerating and terminating the key management personnel or service providers of the joint arrangement. The considerations made in determining joint control are similar to those necessary to determine control over subsidiaries.

Classifying the arrangement requires the Group to assess its rights and obligations arising from the arrangement. Specifically, the Group considers:

- The structure of the joint arrangement – whether it is structured through a separate vehicle.
- When the arrangement is structured through a separate vehicle, the Group also considers the rights and obligations arising from:
- The legal form of the separate vehicle;
- The terms of the contractual arrangement;
- Other facts and circumstances (when relevant).

As the Group has a proportionate share of the rights to the PSAs' assets and the obligations for the PSAs' liabilities, it classifies these interests as a Joint Operation under IFRS 11, and presents its proportionate share of the assets, liabilities, revenues and expenses on a line-by-line basis in the interim condensed consolidated financial statements.

CRITICAL ACCOUNTING ESTIMATES - CONTINUED

This assessment often requires significant judgement, and a different conclusion on joint control and also whether the arrangement is a joint operation or a joint venture, may materially impact the accounting.

If the Group did not have both joint control and a proportionate share of the rights to the PSAs' assets and obligations for the PSAs' liabilities, it would present only its net investment in the PSAs and its proportionate share of the PSAs' net income in the consolidated financial statements.

ACCOUNTING FOR LEASES AND JOINT OPERATIONS

Where the Group participates in a joint operation, either as a lease operator or non-operator party, determining whether to recognize and whether to measure a lease obligation involves judgement and requires identification of which entity has primary responsibility for the lease obligations entered into in relation to the joint operation's activities.

Where the joint operation (including all parties to that arrangement) has the right to control the use of the identified asset and all parties have a legal obligation to make payments to the third-party supplier, each joint operation participant would recognize its proportionate share of the lease related balances. This may arise where all parties to an unincorporated joint operation sign the lease agreement, or the joint operation is some sort of entity or arrangement that can sign in its own name.

However, where the Group is the lead operator and the sole signatory such that it is the one with the legal obligation to pay the third-party supplier, it would recognize 100% of the lease-related balances on its balance sheet. The Group would then need to assess whether the arrangement with the non-operator parties contains a sublease. This assessment would be based on the terms and conditions of each arrangement and may be impacted by the legal jurisdiction in which the joint arrangement operates.

Regardless of whether there is a sublease or not, the Group, in case it acts as the lead operator, would continue to recognize the lease liability for as long as it remains a party to the arrangement with the third-party supplier and has primary obligation to the lease payments.

REVENUE RECOGNITION

Judgement is required in determining when and how much revenue to recognize from contracts with customers. While the Group has determined that all revenue from contracts with customers is earned at a point in time, there is judgement involved in this consideration. Contractual arrangements for the sale of different products or with different terms may result in revenue being recognized over time.

There is also judgement involved in assessing whether the Group is the principal or agent in revenue transactions. In determining that the Group is acting as principal, the terms of the agreements were carefully considered and it was concluded that the Group controls the product before it is transferred to the customer. In alternate arrangements, the Group could be determined to be acting as agent.

Under the terms of existing contracts, the Group has determined that shipping or transportation services are not being provided to the customer, and that the only performance obligations are for the sale of crude oil and natural gas. Judgement is required in determining whether shipping is being provided as a service, and this impacts on the identification of performance obligations, whether all performance obligations are recognized at a point in time or over time, and the overall timing of revenue recognition.

Finally, judgement is required to determine whether the contractual arrangements contain only variable consideration, or also embedded derivatives, and if variable consideration, whether to exercise the constraint.

TAXES

Judgement is required to determine which arrangements are considered to be a tax on income as opposed to production costs. Judgement is also required to determine whether deferred tax assets are recognized in the statement of financial position. Deferred tax assets, including those arising from tax losses carried forward, require management to assess the likelihood that the Group will generate sufficient taxable earnings in future periods in order to utilize recognized deferred tax assets.

Assumptions about the generation of future taxable profits depend on management's estimates of future cash flows. These estimates of future taxable income are based on forecast cash flows from operations (which are impacted by production and sales volumes, oil and gas prices, reserves, production costs, decommissioning costs, capital expenditure, dividends and other capital management transactions) and judgement about the application of existing tax laws in each jurisdiction.

To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Group to realize the net deferred tax assets recorded at the reporting date could be impacted. In addition, future changes in tax laws in the jurisdictions in which the Group operates could limit the ability of the Group to obtain tax deductions in future periods.

CRITICAL ACCOUNTING ESTIMATES - CONTINUED

UNITS-OF-PRODUCTION DEPRECIATION OF OIL AND GAS PROPERTIES

Oil and gas properties are depreciated using the UoP-method over total estimated proved and probable hydrocarbon reserves. This results in a depletion charge that is proportional to the depletion of the anticipated remaining production from the field.

The life of each item, which is assessed at least annually, has regard to both its physical life limitations and present assessments of economically recoverable reserves of the field at which the asset is located. These calculations require the use of estimates and assumptions, including the amount of recoverable reserves.

The calculation of the UoP-rate of depreciation could be impacted to the extent that actual production in the future is different from current forecast production based on total estimated proved and probable reserves, or future capital expenditure estimates change.

Changes to proved and probable reserves could arise due to changes in the factors or assumptions used in estimating reserves, including the effect on proved and probable reserves of differences between actual commodity prices and commodity price assumptions or unforeseen operational issues.

GOING CONCERN

The interim condensed consolidated financial statements for Q1 2025 have been prepared on a going concern basis, which assumes that the Company will be able to realize its assets and discharge its liabilities in the normal course of business as they become due.

INTERNAL FINANCIAL REPORTING AND DISCLOSURE CONTROLS

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the Company's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

In accordance with the provisions of NI 52-109, management, including the Chief Executive Officer and the Chief Financial Officer, have limited the scope of the design of the Company's disclosure controls and procedures of Prime. Results for Prime, which was acquired on March 19, 2025, reflected in the unaudited interim condensed consolidated financial statements and related notes of the Company for the three months ended March 31, 2025, include current assets of $516.8 million, non-current assets of $1,588.9 million, current liabilities of $417.0 million, non-current liabilities of $1,026.2 million as of March 31, 2025, and revenues of $76.4 million and profit before tax of $10.8 million for the period since the transaction closed. The scope limitation is primarily due to the time required for the Company's management to assess Prime's controls and procedures in a manner consistent with the Company's current operations.

Subject to the scope limitation described above, management, including the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of the Company's disclosure controls and procedures. As of March 31, 2025, the Chief Executive Officer and Chief Financial Officer have each concluded that the Company's disclosure controls and procedures, as defined in NI 52-109 - Certification of Disclosure in Issuer's Annual and Interim Filings, are effective to achieve the purpose for which they have been designed.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

Internal controls over financial reporting are designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with IFRS Accounting Standards. Management is also responsible for the design of the Company's internal control over financial reporting in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS Accounting Standards.

The Company's internal controls over financial reporting include policies and procedures that: pertain to the maintenance of records that, in reasonable detail accurately and fairly reflect the transactions and disposition of assets; provide reasonable assurance that transactions are recorded as necessary to permit preparation of the financial statements in accordance with IFRS Accounting Standards and that receipts and expenditures are being made only in accordance with authorization of management and directors of the Company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on the financial statements.

Management, including the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of the Company's internal controls over financial reporting. As at March 31, 2025, the Chief Executive Officer and Chief Financial Officer have each concluded that the Company's internal controls over financial reporting, as defined in NI 52-109 - Certification of Disclosure in Issuer's Annual and Interim Filings, are effective to achieve the purpose for which they have been designed. Because of their inherent limitations, internal controls over financial reporting can provide only reasonable assurance and may not prevent or detect misstatements. Furthermore, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

ADVISORY REGARDING OIL AND GAS INFORMATION

The terms boe (barrel of oil equivalent) and MMboe (millions of barrels of oil equivalent) are used throughout this report. Such terms may be misleading, particularly if used in isolation. The conversion ratio of six thousand cubic feet per barrel (6 Mcf:1 Bbl) of conventional natural gas to barrels of oil equivalent and the conversion ratio of 1 barrel per six thousand cubic feet (1 Bbl:6 Mcf) of barrels of oil to conventional natural gas equivalent is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to conventional natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

In this report, references are made to historical and potential future oil production in Nigeria and Namibia. In all instances these references are to light and medium crude oil category in accordance with NI 51-101 and the COGE Handbook.

Reserves are estimated remaining quantities of petroleum anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are further classified according to the level of certainty associated with the estimates and may be sub-classified based on development and production status. Proved Reserves are those quantities of petroleum, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations. Probable Reserves are those additional quantities of petroleum that are less certain to be recovered than Proved Reserves, but which, together with Proved Reserves, are as likely as not to be recovered. Possible Reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

RISK FACTORS

With Board oversight, the Company proactively manages the identification, assessment and mitigation of risks, many of which are common to operations in the oil and gas industry as a whole, whilst others are unique to the Company. The realization of any of the risks listed below could have a material adverse effect on the Company's business, financial condition, reserves and results of operations, such list being non-exhaustive.

The risks noted in the risk factors section comprises those that can materially affect the figures presented and disclosures in the Financial Statements and MD&A. The Company's Annual Information Form contains a more comprehensive list of risks that can affect the Company.

INCREASED COSTS AND SUPPLY DISRUPTION

A failure to secure the services and equipment necessary for the Company's operations for the expected price, on the expected timeline, or at all, may have an adverse effect on the Company's financial performance and cash flows. The Company's operating and capital costs could escalate and become uncompetitive due to supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs, and additional government intervention through stimulus spending or additional regulations. The Company's inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on its financial performance and cash flows. In addition, with rising inflation levels combined with global cost of living expenses, the Company may be faced with the challenge of how to attract and retain employees. Though Africa Oil does not directly control procurement decisions associated with our non-operating assets, the Company works with its JV parties to ensure adequate contingency for cost inflation is incorporated into capital and operating budgets and that costs are controlled within budget.

PRICES, MARKETS AND MARKETING OF CRUDE OIL AND NATURAL GAS

Crude 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 the Company. World prices for oil and gas have fluctuated widely in recent years. Any material decline in prices could have an adverse effect on the Company's business and prospects. The Company may be required by government authorities to limit production due to OPEC+ quotas from time to time. The conflicts in Ukraine and the Middle East have impacted global markets and may continue to result in increased volatility in financial markets and commodity prices. The Company does not have a direct exposure to operations in Ukraine and the Middle East.

The Company ability to market its oil and gas may depend upon its ability to acquire space on vessels or in pipelines that deliver oil and gas to commercial markets. The Company could also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational issues affecting such pipelines and facilities as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and gas and many other aspects of the oil and gas business.

HEDGING

The Group enters into agreements to receive fixed prices on its oil and gas production to offset the risk of revenue reduction if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Group will not benefit from such increases.

RISK FACTORS - CONTINUED

LIQUIDITY AND CASH FLOW

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 require sufficient cash in order to fulfil their work commitments in accordance with contractual obligations, and to be able to potentially acquire strategic oil and gas assets and face potentially unexpected liabilities.

The Company could potentially issue debt or equity, extend its debt maturities and enter into farmout agreements to ensure it has sufficient available funds to meet current and foreseeable financial requirements. Concerns around climate change have resulted in a number of lenders and investors moving away from financing oil and gas activities, and the Company may find access to capital limited, more expensive or made contingent upon environmental performance standards.

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 activities to manage its liquidity position. Notwithstanding any mitigation efforts, the Company remains exposed to erosion of its balance sheet and revenues and may have difficulty in securing necessary funding, which may lead to insufficient liquidity.

CREDIT FACILITIES

The Company is party to credit facilities. The terms of the facilities contain covenants and restrictions on the ability of the Company to, among other things, incur or lend additional debt, pay dividends and make restricted payments, and encumber its assets. The failure of the Company to comply with the covenants contained in the facility or to repay or refinance the facility by its maturity date could result in an event of default, which could, through acceleration of debt, enforcement of security or otherwise, materially and adversely affect the operating results and financial condition of the Company.

FINANCIAL STATEMENTS PREPARED ON A GOING CONCERN BASIS

Africa Oil'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. Africa Oil's operations to date have been financed by equity financing, operating cash flows from its assets in Nigeria, dividends received from equity investments, debt financing and the completion of working interest farmout agreements. Africa Oil'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 the Company 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 Africa Oil be unable to continue as a going concern.

SUBSTANTIAL CAPITAL REQUIREMENTS

Africa Oil expects to make substantial capital expenditures for exploration, development and production of oil and gas reserves in the future. The Company's ability to access the equity or debt markets may be affected by any prolonged market instability. The inability to access the equity or debt markets for sufficient capital, at acceptable terms and within required time frames, could have a material adverse effect on the Company's financial condition, results of operations and prospects.

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 farmout 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 fulfil the minimum work obligations under the terms of its various concessions. Availability of capital will also directly impact the Company's ability to take advantage of acquisition opportunities.

CURRENT GLOBAL FINANCIAL CONDITIONS

Global financial conditions have always been subject to volatility. 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 March 31, 2025.

INTEREST RATE RISK

The Company has borrowed in the past and has a utilized standby credit facility. Interest payments under potential future borrowings could be exposed to volatility in interest rates that could constrain the company's cashflows.

RISK FACTORS - CONTINUED

CREDIT RISK

Credit risk is the risk of loss if counterparties do not fulfil their contractual obligations. Most of the Company's credit exposure relates to amounts due from its JV parties. The risk of the Company's JV parties defaulting on their obligations per their respective joint operating and farmout agreements is mitigated as there are contractual provisions allowing the Company to default JV parties 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.

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 who are resident outside Canada on judgements obtained in courts in Canada predicated on the purchaser's statutory rights and on other civil liability provisions of Canadian securities legislation.

DECOMMISSIONING

The Company is responsible for compliance with all applicable laws, regulations and contractual requirements regarding the decommissioning, abandonment and reclamation of the Company's assets at the end of their economic life, the costs of which may be substantial. It is not possible to predict these costs with certainty since they will be a function of requirements at the time of decommissioning, abandonment and reclamation and the actual costs may exceed current estimates. Laws, regulations and contractual requirements about abandonment and decommissioning may be implemented or amended in the future.

SHAREHOLDER CAPITAL RETURNS

The Company has implemented a base dividend policy and has in the past engaged in share repurchases as part of its commitment to return capital to the shareholders. The amount and frequency of future returns cannot be guaranteed and the Company's performance in this regard is subject to its financial and operational performance that are subject to the risks already outlined. The declaration, timing, amount and payment of dividends remain at the discretion of the Company's Board. Also, the amount and the pace of share buybacks, if implemented, are at the discretion of the Board.

RISKS INHERENT IN OIL AND GAS EXPLORATION, DEVELOPMENT, AND PRODUCTION

Oil and gas operations involve many risks, which, even with the combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of Africa Oil depends on its ability to find, acquire, develop and commercially produce oil and gas reserves. No assurance can be given that the Company will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, the Company may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. It is difficult to project the costs of implementing an exploratory, appraisal or development 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, tools lost in the hole, equipment failures or malfunctions and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof. Without the continual addition of new reserves, any existing reserves associated with the Company's oil and gas assets at any particular time, and the production therefrom, could decline over time as such existing reserves are exploited. There is a risk that additional commercial quantities of oil and gas may not be discovered or acquired by the Company.

Africa Oil's business is subject to all the risks and hazards inherent in businesses involved in the exploration for, and the acquisition, development, production and marketing of, oil and 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 gas wells, production facilities, other property, the environment or personal injury, and such damages may not be fully insurable.

RESERVES AND RESOURCES VOLUMES

There are many uncertainties inherent in estimating quantities of oil and natural gas reserves and resources (contingent and prospective) and the future cash flows attributed to such reserves and resources. The actual production, revenues, taxes and development and operating expenditures with respect to the reserves and resources associated with the Company's assets will vary from estimates thereof and such variations could be material. Estimates of reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. There is uncertainty that it will be commercially viable to produce any portion of the contingent resources. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

GOVERNMENT REGULATIONS AND TAX RISK

The Company may be adversely affected by changes to applicable laws to which it is subject, and its host governments may implement new applicable laws, modify existing ones, or interpret them in a manner that is detrimental to the Company. Such changes to the laws to which the Company is subject could, amongst other things, result in a windfall tax, an increase in existing tax rates or the imposition of new ones or the Company may be subject to tax assessments, all of which on their own or taken together could have a material adverse effect on the Company's business, financial condition, results of operations and prospects of the Company's oil and gas assets.

As has become customary in Nigeria since 2019, the annual budget for Nigeria has been accompanied by a proposed finance bill that supports the revenue needs indicated in the annual budget. This bill could include changes to tax laws, including laws that can affect directly or indirectly the oil and gas industry.

INVESTMENTS IN ASSOCIATES

The Company has invested in other frontier oil and gas exploration companies that face similar risks and uncertainties, which could have a material adverse effect on their businesses, prospects and results of operations. Such risks include, without limitation, equity risk, liquidity risk, commodity price risk, credit risk, currency risk, foreign investment risk, and changes in environmental regulations, economic, political or market conditions, or the regulatory environment in the countries in which they operate. The associates or joint ventures are entities in which the Company has some influence, including through its representation on their Boards, but given its equal or minority interest, no or limited control over their decisions, including, without limitation, financial and operational policies, the Company has no or limited control over outcomes, performance and governance. The Company's access to information is subject to the contractual provisions of shareholder agreements. The Company is reliant on the information provided by investments and may not have the ability to independently verify such information. The Company's investments are not diversified over different types of investments and industries, rather, they are concentrated in one type of investment. If an associated company or jointly controlled entity in which the Company has invested fails, liquidates, or becomes bankrupt, the Company could face the potential risk of loss of some, or all, of its investments, and may be unable to recover any of its investments.

The Company's share price performance is subject to timely communication of financial and operational results. The Company is reliant on its associates and joint ventures for timely and accurate disclosures of material updates. Although the Company has procedures in place to maximise its oversight of such disclosures, including representation on the Boards of its investee companies, failure to mitigate delays and/or inaccuracies in such disclosures could expose the Company to regulatory sanctions and shareholder legal action that could adversely impact the Company's finances and reputation.

INTERNATIONAL OPERATIONS

The Company participates in oil and gas projects located in emerging markets, primarily in Africa. Oil and gas exploration, development and production activities in these emerging markets are subject to significant political, economic, and other uncertainties that may adversely affect the Company's operations. The Company could be adversely affected by changes in applicable laws and policies in the countries where the Company has interests. Additional uncertainties include, but are not limited to, the risk of war, terrorism, 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 gas pricing policies, changes to taxation laws and policies, assessments and audits (including income tax) against the Company by regulatory authorities, difficulty or delays in obtaining necessary regulatory approvals, risks associated with potential future legal proceedings, and the imposition of currency controls. These uncertainties, all of which are beyond the Company's control, could have a material adverse effect on the Company's business, prospects and results of operations. In addition, if legal disputes arise related to oil and gas concessions acquired by the Company, they could be subject to the jurisdiction of courts other than those of Canada. The Company'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 the Company acquires an interest. The Company may require licenses or permits from various governmental authorities to carry out future exploration, development and production activities. There can be no assurance that the Company will be able to obtain all necessary licenses and permits when required.

DIFFERENT LEGAL SYSTEM AND LITIGATION

The Company's exploration, development and production activities are located in countries with legal systems that in various degrees differ from that of Canada. Rules, regulations and legal principles may differ in respect of matters of substantive law and of such matters as court procedure and enforcement. Almost all material exploration and production rights and related contracts of the Company are subject to the national or local laws and jurisdiction of the respective countries in which the operations are carried out. This means that the Company'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.

The Company'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 the Company was to become involved in legal disputes in order to defend or enforce any of its rights or obligations under such concessions, licenses, and agreements or otherwise, such disputes or related litigation could be costly, time consuming and the outcome would be highly uncertain. Even if the Company ultimately prevailed, such disputes and litigation may still have a substantially negative effect on the Company's business, assets, financial conditions, and its operations.

RISK FACTORS - CONTINUED

BRIBERY, CORRUPTION AND FRAUD

The Company is subject to various laws which aim to combat bribery, corruption and fraud, including the Corruption of Foreign Public Officials Act (Canada) and the Bribery Act 2010 (United Kingdom) and the Economic Crime and Corporate Transparency Act 2023 (United Kingdom). Failure to comply with such laws could subject the Company to, among other things, civil and criminal penalties, other remedial measures and legal expenses and reputational damage, each of which could adversely affect the Company's business, results in operations, and financial condition. Weaknesses in the anti-corruption legal and judicial system of certain countries may undermine the Company's or a host government's capacity to effectively detect, prevent and sanction corruption and fraud. To mitigate this risk, the Company has implemented an anti-corruption compliance and onboarding program for anyone that does business with the Company, anti-corruption training initiatives for its personnel and consultants, and an anti-corruption policy for its personnel, and consultants. However, the Company cannot guarantee that its personnel, contractors, or business partners have not in the past or will not in the future engage in conduct undetected by the onboarding processes and procedures adopted by the Company, and it is possible that the Company, its personnel or contractors, could be subject to investigations or charges related to bribery, corruption or fraud as a result of actions of its personnel or contractors.

SHARED OWNERSHIP AND DEPENDENCY ON JV PARTIES

The Company's operations are primarily conducted together with one or more JV parties through contractual arrangements, including unincorporated associations. In such instances, the Company may be dependent on, or affected by, the due performance and financial strength of its JV parties. If a JV party fails to perform or becomes insolvent, the Company may, among other things, risk losing rights or revenues or incur additional obligations or costs, experience delays, or be required to perform such obligations in place of its JV party. The Company and its JV parties 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 JV parties relating to a project, such dispute may have material adverse effect on the Company's or investee company's operations relating to such project.

RISKS RELATING TO CONCESSIONS, LICENSES AND CONTRACTS

Africa Oil'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 Africa Oil. In case of a dispute, it cannot be certain that the view of the Company would prevail or that the Company otherwise could effectively enforce its rights which, in turn, could have significantly negative effects on Africa Oil. Also, if the Company or any of its JV parties were found to have failed to comply with their obligations or liabilities under a concession, license or contract, including record-keeping, budgeting, and time scheduling requirements, the Company's or JV parties rights under such concession, license or contract may be terminated or otherwise relinquished in whole or in part. The Company cannot guarantee that requirements are adequately met by its JV parties, which could bring an increased risk of impairment and reduced future cash flow.

In May 2023, the Company submitted notices to withdraw from its concessions on Blocks 10BB, 13T and 10BA in Kenya. The Company's withdrawal from the concessions is subject to approvals from the Kenyan authorities and, while the Company is working with its JV parties and the authorities to effect a smooth withdrawal process, there can be no certainty that such approvals will be forthcoming on terms acceptable to all parties.

RISKS RELATING TO INFRASTRUCTURE

Africa Oil is dependent on having available and functioning infrastructure relating to the properties and licenses on which it operates, such as roads, power and water supplies, pipelines and gathering systems, supply bases and associated services.

The amount of oil and gas that the Company can produce, and sell is subject to accessibility, availability, proximity and capacity of gathering, processing and pipeline systems. The lack of availability of capacity or a failure in any of the gathering, processing and pipeline systems, and in particular the processing facilities could result in the Company's inability to realize the full economic potential of its production or in a reduction of the price offered for the Company's production. Any significant change in market factors, terms of use or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Company's business financial condition, results of operations, cash flows and future prospects.

In Nigeria, gas export relies on the continued safe operations at the Nigeria LNG facility. Gas export restrictions could have an adverse effect on oil production, due to reductions in overall facility production to minimise flaring of associated gas. The supply chain for offshore is dependent upon existing ports and onshore infrastructure. Several factors, including social unrest onshore, have the potential to disrupt both the gas processing facilities and the upstream supply chain which could have detrimental impacts on Prime's cashflow and subsequent dividend payments to Africa Oil.

In Equatorial Guinea, exploration efforts in Block EG-31 are targeting gas prospects located close to existing gas export and processing facilities. In the event of a discovery, the discovered fluids may not be compatible with the existing processing facilities resulting in additional cost which may result in the potential discovery being non-commercial. There may also be insufficient ullage in the facilities to accept additional capacity and without appropriate commercial arrangements it may not be possible to produce any potential discovery.

INSURANCE

The Company's involvement in oil and gas operations may result in the Company becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. While the Company obtains insurance in accordance with industry standards to address such risks, the nature of the risks facing the oil and gas industry is such that liabilities might exceed policy limits, the liabilities and hazards might not be insurable, or the Company might elect not to insure itself against such liabilities due to high premium costs or other reasons. The payment of such uninsured liabilities would reduce the funds available to the Company. The occurrence of a significant event that the Company is not fully insured against, or the insolvency of an insurer, could have a material adverse effect on the Company's business, financial condition and results of operations. There can be no assurance that insurance will be available in the future.

CLIMATE RISKS

MARKET RISKS

Changing consumer preferences for low carbon sources of energy, transport and products and services may erode demand for oil and gas as alternatives come to market and gain scale. Reduced demand for oil and gas may result in stranded reserves or resources and negatively impact the Company's valuation and share price. In addition to limiting the Company's ability to sell into the market, these trends could lead to lower commodity prices in the medium and long-term, putting further pressure on revenues. In the short-term, unbalanced investment in traditional vs. new energy technologies and sources, combined with uncertain demand dynamics, may lead to commodity price volatility. Supply chains may also become constrained, as suppliers adjust their strategies and product mix in response to the energy transition, resulting in increasing costs for some goods and services.

The Company has conducted scenario analysis, which suggests the current portfolio remains competitive in a low demand environment. We update our analysis on a regular basis and ahead of new project sanction to minimize the risk of stranded assets. In order to remain resilient in an uncertain and volatile future commodity environment, the Company works with and through its parties to reduce operational costs as much as possible without sacrificing health and safety or longer-term efficiency and environmental or strategic goals. Additionally, the Company will maintain a prudent budget and financial strategy, including hedging as appropriate, to manage medium term oil price volatility ensure the business remains resilient in a low oil price environment.

LITIGATION RISKS

Climate-related litigation is a rapidly evolving and increasingly important issue for our industry. The risk of legal challenges could rise as the costs of climate change mitigation and adaptation increase, and as more climate laws and agreements are put in place. Climate-related litigation could result in liabilities or loss of license related to current or historical activities' contribution to global emissions. We do not consider Africa Oil at immediate risk of climate litigation but are monitoring developments closely. Even if the Company is not directly targeted by litigation, operations may be indirectly impacted by outcomes in related cases involving other oil and gas companies in jurisdictions where we operate. The Company will seek legal counsel as required to remain abreast of potential legal action and its implications for our business.

REGULATORY RISKS

Since the Paris Agreement was signed in 2015, countries have steadily enacted policies to enable the transition to a low carbon future and meet their Nationally Determined Contributions (NDCs). This includes the governments of countries where Africa Oil conducts business. These policies may directly or indirectly increase the cost of doing business in these countries or potentially restrict the Company's ability to operate. Africa Oil regularly monitors the evolving regulatory landscape, both globally and in the Company's countries of operation, to anticipate the impact of new climate-related measures and ensure the Company remains compliant. Additionally, the Company is developing a comprehensive energy transition strategy, including measures to minimize operational emissions in line with Paris Agreement objectives, which should help the Company to remain aligned with evolving regulatory requirements and minimize negative impacts.

REPUTATIONAL RISK

Increased scrutiny, pressure and action by environmental activists, non-governmental organizations and other stakeholders may result in disruption to operations or loss of license to operate. Such disruption may negatively impact cash flows, returns or the value of our portfolio. Similarly, companies within the sector and our supply chain may make emissions performance and climate risk management explicit in partner or contract decisions. The Company has not been directly targeted by environmental activists but could be targeted in the future. To mitigate this risk, Africa Oil proactively engages with the communities and other stakeholders where the Company operates to keep them informed about the impact of our operations on the environment and their livelihoods. The Company also ensures proper security is in place to minimize the impact of any potential disruptions and prevent harm to staff, bystanders and assets.

In addition to environmental activists, numerous banks and large institutional investors have communicated an intention to divest from or limit future exposure to fossil fuels, including oil and gas. Increasing investor and lender concerns regarding climate resilience could limit access to capital, increase the cost of that capital via higher interest rates or result in direct costs associated with new measures to meet investor expectations. Since 2020, Africa Oil has published public climate disclosures aligned with the Taskforce for Climate-Related Financial Disclosures (TCFD) recommendations to proactively address investor and other stakeholder concerns regarding climate risk exposure. In addition, Africa Oil regularly engages with investors and lenders to understand their climate policies and requirements and to inform them about the steps the Company is taking to manage climate risks. This includes development of a strategy to minimize operational emissions.

CLIMATE RISKS - CONTINUED

PHYSICAL RISKS

Climate change has already resulted in significant shifts in global weather patterns, including an increase in the number and severity of heat waves, cold spells, droughts and storms, including hurricanes and tropical cyclones. Longer term, climate change may also result in rising sea levels due to melting polar ice caps. The physical effects of climate change have the potential to directly impact the Company's assets and operations. In 2022, the Company contracted a global climate risk analytics company to perform a quantified assessment of the physical climate risks facing the Company's assets under three IPCC climate scenarios: SSP1-2.6 (consistent with 1.8°C warming), SSP2-4.5 (consistent with 2.7°C warming) and SSP5-8.5 (consistent with 4.4°C warming). That analysis suggests exposure to future changes in physical climate hazards is relatively minimal compared to the historical baseline across all three scenarios. We will continue to monitor our assets' exposure to physical climate risks as our portfolio and the global scientific community's understanding of changing climate patterns evolves.

OTHER ENVIRONMENTAL RISKS

The regulatory frameworks in the Company's countries of operation extend beyond emissions to include broader areas of environmental concern, including water management, waste handling, soil pollution and biodiversity protection. These regulations typically include environmental licensing and permitting subject to the conduct of Environmental and Social Impact Assessments prior to any new exploration or development activity, as well as ongoing monitoring and reporting.

Non-compliance with environmental regulations can result in fines or permits being revoked, both of which could materially impact the Company's financial position or license to operate. Breaches could also lead to civil or criminal litigation, particularly in cases resulting in significant environmental damage.

The Company is committed to minimizing the broader environmental impact of its activities. The Company acts in compliance with the applicable environmental laws and regulations of its countries of operation and manages activities according to good international practice. This includes taking a rigorous approach to operational planning, including identifying potential environmental or social risks and impacts of operations, and obtaining and maintaining all necessary permits and licenses. The Company also consults with stakeholders on environmental issues that may affect them, investigates any environmental incidents, and maintains emergency response procedures for protection of the environment.

The Company assesses and puts measures in place to minimize impact on biodiversity and ecosystem services in line with the mitigation hierarchy to ensure that activities lead to no net loss of natural habitats. Where the Company is not the operator, it monitors environmental risk management via regular reports from JV parties and operators and participation in quarterly operating and technical committee meetings.

Though the Company endeavors to engage all relevant stakeholders proactively and early in the project planning process, environmental activism is increasing, and in some cases has resulted in delays or disruptions to activities, including delays to permitting where activists have challenged permits in courts. Africa Oil has not to date suffered impacts to operations due to environmental activism. However, such delays could affect project economics by incurring additional costs or delaying forecast production and revenues.

The Company does not currently face any environmental fines or charges. However, accidents can occur and the unexpected nature of these events makes the timing and scope challenging to quantify with respect to financial impacts.

SIGNIFICANT SHAREHOLDER

BTG Oil & Gas, an investment company which is a subsidiary of BTG Pactual, the largest investment bank in Latin America based in Sao Paolo, Brazil, owns approximately 35.5 percent of the aggregate common shares of the Company. BTG Oil & Gas's holdings may allow it to significantly affect substantially all the actions taken by the shareholders of the Company, including the election of directors. As long as BTG Oil & Gas maintains a significant interest in the Company, it is likely that BTG Oil & Gas will exercise significant influence on the ability of the Company to, among other things, enter into a change in control transaction of the Company and may also discourage acquisition bids for the Company. There is a risk that the interests of BTG Oil & Gas may not be aligned with the interests of other shareholders.

FORWARD-LOOKING STATEMENTS

Certain statements in this document may constitute forward-looking information or forward-looking statements under applicable Canadian securities law (collectively "forward-looking statements"). Forward-looking statements are statements that relate to future events, including the Company's future performance, opportunities or business prospects. All statements other than statements of historical fact may be forward-looking statements. Statements concerning proven and probable reserves and resource estimates may also be deemed to constitute forward-looking statements and reflect conclusions that are based on certain assumptions that the reserves and resources can be economically exploited. Any statements that express or involve discussions with respect to expectations, forecasts, assumptions, objectives, beliefs, projections, plans, guidance, predictions, future events or performance (often, but not always, identified by words such as "believes", "seeks", "anticipates", "expects", "continues", "may", "projects", "estimates", "forecasts", "pending", "intends", "plans", "could", "might", "should", "will", "would have" or similar words suggesting future outcomes) are not statements of historical fact and may be forward-looking statements.

By their nature, forward-looking statements 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 such forward-looking statements. Undue reliance should not be placed on these forward-looking statements because the Company cannot assure that the forward-looking statements will prove to be correct. As forward-looking information address future conditions and events, they could involve risks and uncertainties including, but are not limited to, risk with respect to macro-economic conditions and their impact on operations, 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.

Forward-looking statements include, but are not limited to, statements concerning:

- A change to the shareholder capital return program including the implementation of share buy-backs;
- The completion and timing of proposed transactions;
- Planned exploration, appraisal and development activity including both expected drilling, and geological and geophysical related activities;
- Potential for an improved economic environment;
- Proposed development plans;
- Future development costs and the funding thereof;
- Expected funding and development costs;
- Anticipated future financing requirements;
- Future sources of funding for the Company's capital program;
- Future capital expenditures and their allocation to exploration and development activities;
- Expected operating costs;
- Future sources of liquidity, ability to fully fund the Company's expenditures from cash flows, and borrowing capacity;
- Availability of potential farmout partners/ parties;
- Government or other regulatory consent for exploration, development, farmout, or acquisition activities;
- Future production levels;
- Future crude oil or natural gas prices;
- Future earnings;
- The Company's ability to deliver further growth and expectations regarding free-cash flow;
- Future asset acquisitions or dispositions and the anticipated strategic and financial benefits of those transactions;
- Future debt levels;
- Availability of committed credit facilities, including existing credit facilities, on terms and timing acceptable to the Company;
- Possible commerciality;
- Development plans or capacity expansions;
- Future ability to execute dispositions of assets or businesses;
- Future drilling of new wells;
- Ultimate recoverability of current and long-term assets;
- Ultimate recoverability of reserves or resources;
- The sustainability of the Company across oil and gas price cycles;
- 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;

FORWARD-LOOKING STATEMENTS - CONTINUED

- The Company's ability to comply with future legislation or regulations;
- Future staffing level requirements; 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.

These 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;
- Uncertainty of estimates and projections relating to reserves, resources, production, revenues, costs and expenses;
- Changes in exploration or development project plans or capital expenditures;
- The Company's ability to explore, develop, produce and transport crude oil and natural gas to markets;
- Production and development costs and capital expenditures;
- The imprecise nature of reserve estimates and estimates of recoverable quantities of oil, natural gas and liquids;
- Changes in oil prices;
- Availability of financing;
- Uninsured risks;
- Changes in interest rates and foreign-currency exchange rates;
- Regulatory changes;
- Changes in the social climate in the regions in which the Company operates;
- Health, safety and environmental risks;
- Climate change legislation and regulation changes;
- Defects in title;
- Availability of materials and equipment;
- Timelines of government or other regulatory approvals;
- 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 indicate 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;
- Economic conditions in the countries and regions in which the Company carries on business;
- Governmental actions including changes to taxes or royalties, and changes in environmental and other laws and regulations;
- The Company's treatment under governmental regulatory regimes and tax laws;
- 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 its assessment of all available information at that time. Although management believes that the expectations conveyed by the forward-looking statements are reasonable based on the information available to it on the date such forward-looking statements were made, no assurances can be given that such expectations will prove to be correct, and such forward-looking statements included in, or incorporated by reference into, this document should not be unduly relied upon.

The forward-looking statements are made as of the date hereof or as of the date specified in the documents incorporated by reference into this document, as the case may be, and except as required by law, the Company undertakes no obligation to update publicly, re-issue, or revise any forward-looking statements, whether as a result of new information, future events or otherwise. This cautionary statement expressly qualifies the forward-looking statements contained herein.

INTERIM CONDENSED CONSOLIDATED BALANCE SHEET

(Expressed in millions of United States dollars)

As at	Note	March 31, 2025	December 31, 2024
ASSETS			
Non-current assets			
Oil and gas properties	5	1,588.8	-
Intangible exploration assets	6	39.0	29.3
Other tangible fixed assets		3.2	3.2
Equity investment in joint venture	7	-	328.4
Equity investments in associates	8	143.1	177.6
		1,774.1	538.5
Current assets			
Inventories	9	94.8	-
Investment held for sale	10	-	7.0
Loan to associated company	26	-	4.3
Trade and other receivables	11	211.9	4.0
Cash and cash equivalents	12	428.4	61.4
		735.1	76.7
Total assets		2,509.2	615.2
LIABILITIES AND EQUITY			
Equity attributable to common shareholders			
Share capital	13(B)	1,534.8	1,195.8
Contributed surplus		95.5	87.4
Treasury share account		-	(0.4)
Deficit		(708.1)	(734.0)
Total equity attributable to common shareholders		922.2	548.8
Non-current liabilities			
Financial liabilities	15	408.8	2.6
Provisions	14	295.5	49.2
Deferred tax liabilities		331.1	-
		1,035.4	51.8
Current liabilities			
Financial liabilities	15	214.4	0.7
Trade and other payables	16	162.4	9.7
Current tax liabilities		49.9	-
Dividends	17	25.0	-
Provisions	14	99.9	4.2
		551.6	14.6
Total liabilities		1,587.0	66.4
Total liabilities and equity attributable to common shareholders		2,509.2	615.2

The notes are an integral part of the interim condensed consolidated financial statements.

Approved on behalf of the Board:

"MICHAEL EBSARY"

MICHAEL EBSARY, DIRECTOR

"ROGER TUCKER"

ROGER TUCKER, DIRECTOR

INTERIM CONDENSED CONSOLIDATED STATEMENTS OF NET INCOME AND OTHER COMPREHENSIVE INCOME

(Expressed in millions of United States dollars)

For the three months ended	Note	March 31, 2025	March 31, 2024
Revenue	20	76.4	-
Cost of Sales			
Production costs	21	(51.2)	-
Depletion costs	5	(12.1)	-
		(63.3)	
Gross profit		13.1	-
General and administrative expenses		(13.5)	(5.1)
Operating loss		(0.4)	(5.1)
Finance income	22	1.1	2.7
Finance expense	23	(2.8)	(1.3)
Net financial items		(1.7)	1.4
Share of profit from investment in joint venture	7	15.9	21.5
Share of loss from investments in associates	8	(2.0)	(14.3)
Reversal of impairment of investment in joint venture	7	42.9	-
Profit before tax		54.7	3.5
Income tax	24	(3.8)	-
Net income attributable to common shareholders		50.9	3.5
Total comprehensive income		50.9	3.5
Net income attributable to common shareholders per share			
Basic	25	0.11	0.01
Diluted	25	0.11	0.01
Weighted average number of shares outstanding for the purpose of calculating earnings per share			
Basic	25	468,472,433	460,990,598
Diluted	25	476,836,682	474,745,624

The notes are an integral part of the interim condensed consolidated financial statements.

INTERIM CONDENSED CONSOLIDATED STATEMENTS OF EQUITY

(Expressed in millions of United States dollars)

For the three months ended	Note	March 31, 2025	March 31, 2024
Share capital:	13(B)		
Balance, beginning of the period		1,195.8	1,265.3
Share issuance to BTG Oil & Gas under amalgamation Agreement	13	353.2	-
Exercise of Share Options	13	-	0.1
Settlement of Restricted Share Units	13	1.1	-
Settlement of Performance Share Units	13	1.5	-
Weighted average value of shares cancelled	13	(16.8)	(19.3)
Balance, end of the period		1,534.8	1,246.1
Contributed surplus:			
Balance, beginning of the period		87.4	61.6
Excess of weighted value of shares cancelled	13	8.1	6.8
Balance, end of the period		95.5	68.4
Treasury account:			
Balance, beginning of the period		(0.4)	-
Shares purchased	13	(8.3)	(13.9)
Shares cancelled	13	8.7	12.5
Balance, end of the period		-	(1.4)
Deficit:			
Balance, beginning of the period		(734.0)	(432.3)
Dividends	13	(25.0)	(11.5)
Net income attributable to common shareholders		50.9	3.5
Balance, end of the period		(708.1)	(440.3)
Total equity attributable to common shareholders			
Balance, end of the period		922.2	872.8

The notes are an integral part of the interim condensed consolidated financial statements.

INTERIM CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS

(Expressed in millions of United States dollars)

For the three months ended	Note	March 31, 2025	March 31, 2024
Cash flows generated by/ (used in):			
Operations:			
Profit before tax		54.7	3.5
Adjustments for:			
Reversal of impairment of investment in joint venture	7	(42.9)	-
Share of loss from investments in associates	8	2.0	14.3
Share of profit from investment in joint venture	7	(15.9)	(21.5)
Net financial items	22/23	1.7	(1.4)
Depletion costs	5	12.1	-
Share-based compensation		4.0	0.5
Taxes		(16.0)	-
Other		(0.6)	(1.0)
Net cash used in operating activities before working capital		(0.9)	(5.6)
Changes in working capital		37.3	(3.1)
Net cash generated / (used) in operating activities		36.4	(8.7)
Investing:			
Expenditures on oil and gas properties and intangible exploration assets	5/6	(3.6)	(4.8)
Distribution received from joint venture	7	60.0	-
Distribution received from associates	8	31.6	-
Loan repaid by / (provided to) associated company	26	4.5	(0.3)
Interest income received		0.9	2.4
Cash acquired from Prime consolidation	4	380.4	-
Net cash generated / (used) in investing activities		473.8	(2.7)
Financing:			
Repayment RBL Facility		(130.0)	-
Repayment of principal portion of lease commitments	14	(0.1)	(0.1)
Dividends paid to shareholders		-	(11.5)
Repurchase of share capital	13	(8.3)	(13.9)
Interest expense paid		(4.9)	-
Net cash used in financing activities		(143.3)	(25.5)
Effect of exchange rate changes on cash and cash equivalents denominated in foreign currency		0.1	0.4
Increase/ (decrease) in cash and cash equivalents		367.0	(36.5)
Cash and cash equivalents, beginning of the period	12	61.4	232.0
Cash and cash equivalents, end of the period	12	428.4	195.5

The notes are an integral part of the interim condensed consolidated financial statements.

NOTES TO INTERIM CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

For the three months ended March 31, 2025, and March 31, 2024
(Expressed in millions of United States dollars unless otherwise indicated)

1. Incorporation and nature of business:

Africa Oil Corp. (collectively with its subsidiaries, "AOC" or the "Company" or the "Group") was incorporated on March 29, 1993, under the laws of British Columbia and is an international oil and gas exploration and production company based in Canada with oil and gas interests in Africa. The Company's registered address is 25th Floor, 666 Burrard Street, Vancouver, B.C., Canada V6C 2X8.

2. Basis of preparation:

A. Statement of compliance:

The Company prepares its interim condensed consolidated financial statements in accordance with Canadian generally accepted accounting principles for interim periods, specifically International Accounting Standard 34 Interim Financial Reporting as issued by the International Accounting Standards Board. They are condensed as they do not include all the information required for full annual financial statements and they should be read in conjunction with the consolidated financial statements for the year ended December 31, 2024.

The policies applied in these interim condensed consolidated financial statements are based on International Financial Reporting Standards as issued by the International Accounting Standards Board (''IFRS Accounting Standards'') issued and outstanding as at May 14, 2025, the date the Board of Directors approved the statements.

B. Basis of measurement:

The interim condensed consolidated financial statements have been prepared on the historical cost basis. Where there are assets and liabilities calculated on a different basis, this fact is disclosed in the material accounting policy. Identifiable assets acquired and liabilities assumed in the transaction with BTG Oil & Gas were measured at its acquisition date fair value based on guidance in IFRS 13 as per Note 4. Certain comparative figures have been reclassified to conform with the financial statements presentation in the current year following completion of the transaction with BTG. The Company has changed the presentation of its share of profit from investment in joint venture and associated companies in the interim condensed consolidated statement of net income and comprehensive income. The Company has also changed the presentation of interest income received in the interim condensed consolidated statement of cash flows.

C. Functional and presentation currency:

These interim condensed consolidated financial statements are presented in United States (US) dollars. The functional currencies of the Company's individual entities are US dollars which represents the currency of the primary economic environment in which the entities operate.

The interim condensed consolidated financial statements are expressed in millions of US dollars unless otherwise indicated.

D. Use of estimates and judgements:

The preparation of financial statements in conformity with IFRS requires management to make judgements, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates. Items subject to estimates and judgement have been described in the Company's audited consolidated financial statements for the year ended December 31, 2024. The following additional items are subject to estimates and judgement following completion of the transaction with BTG Oil & Gas to consolidate the interest in Prime Oil and Gas Coöperatief U.A. ("Prime").

Classification of joint arrangements

These interim condensed consolidated financial statements include transactions of non-operated Production Sharing Agreements ('PSAs'). The PSA transactions include the Group's proportionate share of the PSAs assets, liabilities and expenses, with items of a similar nature on a line-by-line basis, from the date that participation in the PSA arrangements commenced.

The Group has applied judgment in determining that it has joint control over the PSAs. This determination recognizes that all major decisions outside the original scope of the operations require unanimous approval by at least the Group and one or more of the PSAs partners.

The Group has determined that the relevant activities for its joint arrangements are those relating to the operating and capital decisions of the arrangement, such as approval of the capital expenditure program for each year and appointing, remunerating and terminating the key management personnel or service providers of the joint arrangement. The considerations made in determining joint control are similar to those necessary to determine control over subsidiaries.

NOTES TO INTERIM CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - CONTINUED

Classifying the arrangement requires the Group to assess its rights and obligations arising from the arrangement. Specifically, the Group considers:

- The structure of the joint arrangement – whether it is structured through a separate vehicle.
- When the arrangement is structured through a separate vehicle, the Group also considers the rights and obligations arising from:
- The legal form of the separate vehicle;
- The terms of the contractual arrangement; and
- Other facts and circumstances (when relevant).

As the Group has a proportionate share of the rights to the PSAs' assets and the obligations for the PSAs' liabilities, it classifies these interests as a Joint Operation under IFRS 11, and presents its proportionate share of the assets, liabilities, revenues and expenses on a line-by-line basis in the interim condensed consolidated financial statements.

This assessment often requires significant judgement, and a different conclusion on joint control and also whether the arrangement is a joint operation or a joint venture, may materially impact the accounting.

If the Group did not have both joint control and a proportionate share of the rights to the PSAs' assets and obligations for the PSAs' liabilities, it would present only its net investment in the PSAs and its proportionate share of the PSAs' net income in the consolidated financial statements.

Accounting for leases and joint operations

Where the Group participates in a joint operation, either as a lease operator or non-operator party, determining whether to recognize and whether to measure a lease obligation involves judgement and requires identification of which entity has primary responsibility for the lease obligations entered into in relation to the joint operation's activities.

Where the joint operation (including all parties to that arrangement) has the right to control the use of the identified asset and all parties have a legal obligation to make payments to the third-party supplier, each joint operation participant would recognize its proportionate share of the lease related balances. This may arise where all parties to an unincorporated joint operation sign the lease agreement, or the joint operation is some sort of entity or arrangement that can sign in its own name.

However, where the Group is the lead operator and the sole signatory such that it is the one with the legal obligation to pay the third-party supplier, it would recognize 100% of the lease-related balances on its balance sheet. The Group would then need to assess whether the arrangement with the non-operator parties contains a sublease. This assessment would be based on the terms and conditions of each arrangement and may be impacted by the legal jurisdiction in which the joint arrangement operates.

Regardless of whether there is a sublease or not, the Group, in case it acts as the lead operator, would continue to recognize the lease liability for as long as it remains a party to the arrangement with the third-party supplier and has primary obligation to the lease payments.

Revenue recognition

Judgement is required in determining when and how much revenue to recognize from contracts with customers. While the Group has determined that all revenue from contracts with customers is earned at a point in time, there is judgement involved in this consideration. Contractual arrangements for the sale of different products or with different terms may result in revenue being recognized over time.

There is also judgement involved in assessing whether the Group is the principal or agent in revenue transactions. In determining that the Group is acting as principal, the terms of the agreements were carefully considered and it was concluded that the Group controls the product before it is transferred to the customer. In alternate arrangements, the Group could be determined to be acting as agent.

Under the terms of existing contracts, the Group has determined that shipping or transportation services are not being provided to the customer, and that the only performance obligations are for the sale of crude oil and natural gas. Judgement is required in determining whether shipping is being provided as a service, and this impacts on the identification of performance obligations, whether all performance obligations are recognized at a point in time or over time, and the overall timing of revenue recognition.

Finally, judgement is required to determine whether the contractual arrangements contain only variable consideration, or also embedded derivatives, and if variable consideration, whether to exercise the constraint.

Taxes

Judgement is required to determine which arrangements are considered to be a tax on income as opposed to production costs. Judgement is also required to determine whether deferred tax assets are recognized in the statement of financial position. Deferred tax assets, including those arising from tax losses carried forward, require management to assess the likelihood that the Group will generate sufficient taxable earnings in future periods in order to utilize recognized deferred tax assets.

Assumptions about the generation of future taxable profits depend on management's estimates of future cash flows. These estimates of future taxable income are based on forecast cash flows from operations (which are impacted by production and sales volumes, oil and gas prices, reserves, production costs, decommissioning costs, capital expenditure, dividends and other capital management transactions) and judgement about the application of existing tax laws in each jurisdiction.

To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Group to realize the net deferred tax assets recorded at the reporting date could be impacted. In addition, future changes in tax laws in the jurisdictions in which the Group operates could limit the ability of the Group to obtain tax deductions in future periods.

Units-of-production depreciation of oil and gas properties

Oil and gas properties are depreciated using the UoP-method over total estimated proved and probable hydrocarbon reserves. This results in a depletion charge that is proportional to the depletion of the anticipated remaining production from the field.

The life of each item, which is assessed at least annually, has regard to both its physical life limitations and present assessments of economically recoverable reserves of the field at which the asset is located. These calculations require the use of estimates and assumptions, including the amount of recoverable reserve.

The calculation of the UoP-rate of depreciation could be impacted to the extent that actual production in the future is different from current forecast production based on total estimated proved and probable reserves, or future capital expenditure estimates change.

Changes to proved and probable reserves could arise due to changes in the factors or assumptions used in estimating reserves, including the effect on proved and probable reserves of differences between actual commodity prices and commodity price assumptions or unforeseen operational issues.

Going concern

These interim condensed consolidated financial statements for the three months period ended March 31, 2025, have been prepared on a going concern basis, which assumes that the Company will be able to realize its assets and discharge its liabilities in the normal course of business as they become due.

3. Material accounting policies:

Material accounting policies used in the preparation of these interim condensed consolidated financial statements are described in the Company's consolidated financial statements for the year ended December 31, 2024. The following additional material accounting policies have been used in the preparation of these interim condensed consolidated financial statements following completion of the transaction with BTG Oil & Gas to consolidate the interest in Prime.

Business combinations

Business combinations are accounted for using the acquisition method as at acquisition date, which is the date on which control is transferred to the Group. The cost of an acquisition is measured as the aggregate of the consideration transferred, measured at acquisition date fair value and the amount of any previously held interest in the acquiree.

Acquisition related costs are expensed as incurred and included in general and administrative expenses, except if related to the issue of debt or equity securities.

When the Group acquires a business, it assesses the assets acquired and liabilities assumed for appropriate classification and designation in accordance with the contractual terms, economic circumstances and pertinent conditions as at the acquisition date. Those petroleum reserves and resources that are able to be reliably measured are recognized in the assessment of fair values on acquisition. Other potential reserves, resources and rights, for which fair values cannot be reliably measured, are not recognized.

Any goodwill that arises is tested annually for impairment. Any gain on a bargain purchase is recognized in profit and loss immediately. Goodwill is initially measured at cost, being the excess of the aggregate of the consideration transferred and the amount recognized for NCI over the fair value of the identifiable net assets acquired and liabilities assumed. If the fair value of the identifiable net assets acquired is in excess of the aggregate consideration transferred, the gain is recognized in profit and loss.

After initial recognition, goodwill is measured at cost less any accumulated impairment losses. For the purpose of impairment testing, goodwill acquired in a business combination is, from the acquisition date, allocated to each of the Group's CGUs that are expected to benefit from the combination, irrespective of whether other assets or liabilities of the acquiree are assigned to those units.

Where goodwill forms part of a CGU and part of the operation in that unit or location is disposed of, the goodwill associated with the disposed operation is included in the carrying amount of the operation when determining the gain or loss on disposal. Goodwill disposed in these circumstances is measured based on the relative values of the disposed operation and the portion of the CGU retained.

Revenue recognition

Revenue from contracts with customers is recognized when or as the Group satisfies a performance obligation by transferring a promised good or service to a customer. A good or service is transferred when the customer obtains control of that good or service. As such, revenue is recognized when control of the goods or service transfers to the customer, it is probable that the economic benefits will flow to the Group and the revenue can be reliably measured.

The measurement of revenue, when a performance obligation is satisfied, is based on the amount of the transaction price (excluding estimates of variable consideration that are constrained) that is allocated to that performance obligation, excluding discounts, sales taxes, excise duties and similar levies.

The Group assesses its revenue arrangements against specific criteria in order to determine if it is acting as principal or agent. If the Group acts in the capacity of an agent rather than as the principal in a transaction, then the revenue recognized is the net amount of commission made by the Group. The Group has concluded that it is acting as a principal in all of its revenue arrangements, as described below:

NOTES TO INTERIM CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - CONTINUED

Sales of crude oil and natural gas

Revenue from the sale of crude oil and natural gas is recognized when control of the goods transfers to the customer. The transfer of control of the crude oil and natural gas sold usually coincides with title passing to the customer and the customer taking physical possession. This generally occurs when the product is physically transferred into a vessel, pipe or other delivery mechanism.

Crude oil transaction prices under forward contracts are based on a contract price for the Dated Brent component plus or minus a differential.

In most of the Group's oil offtake contracts, the Dated Brent component of the forward price at the time of entering the contract is not fixed, but determined on or around the date of the lifting for spot cargos either on an average monthly basis, 5-days after bill of lading date or similar pricing mechanism. If the Group wants to utilize the oil offtake contract for commodity risk management, it can either fix the Dated Brent component or utilize a trigger pricing mechanism. For the trigger pricing mechanism, when the forward price curve falls below a certain trigger price for a certain month, this mechanism provides an irrevocable instruction to an off-taker to fix the Dated Brent price component of a cargo. The trigger price is based on a percentage of the Brent forward curve at the time the instruction was given for the month of the expected lifting. If the forward price curve does not fall below that threshold, the respective cargo is sold at spot.

The performance obligation is satisfied and payment is due upon delivery, FOB, to the buyer. At this point in time, at the bill of lading date, a trade receivable is recognized and there are generally 30 days between revenue recognition and payment. There are no obligations for returns, refunds, warranties nor other obligations when control has been transferred. The Group principally satisfies its performance obligations at a point in time.

Revenue from crude oil transactions not covered under oil offtake contracts, arises from the production and lifting of crude oil on an entitlements basis. Under the entitlements method, revenue reflects the Group's share of production under the terms of the relevant production sharing contracts, regardless of which participant has actually made the sale and invoiced the production. This is achieved by applying the following approach in dealing with imbalances between actual sales and entitlements.

- Crude oil entitlement underlifts are recognized at the market price of oil at the balance sheet date. The excess of product sold during the period over the participant's ownership share of production is recognized by the Group (acting as underlifter) as an asset in trade and other receivables with a corresponding credit to production costs. The Group's underlift receivable is the right to receive additional oil from future production without the obligation to fund the production of that additional oil.
- Crude oil entitlement overlifts are treated as a purchase of crude oil by the overlifter from the underlifter and are also recognized at the market price of oil at the balance sheet date. The excess of product purchased during the period over the participant's ownership share of production is recognized by the Group (acting as overlifter) as a liability in trade and other payables with a corresponding charge to production costs. An overlift liability is the obligation to deliver oil out of the Group's equity share of future production.

Revenues resulting from the production of oil under PSAs is recognized for those amounts relating to the Group's cost recoveries and the Group's share of the remaining production.

Royalties

Obligations arising from royalty arrangements and other types of taxes that do not satisfy the criteria of IAS 12 'Income Taxes' are accrued or paid and included in production costs. This is considered to be the case when the royalties are imposed under government authority and the amount payable is based on physical quantities produced or as a percentage of revenue, rather than taxable income. In some cases, the equivalent amount of royalties is also presented in revenues to differentiate between the portion of revenue lifted by the operator on behalf of the Group to settle the Group's royalty liabilities and the associated royalties as part of production costs. In cases where the Group itself pays for the royalties in cash, these are included in production costs as a single line item.

Production costs

The costs of producing oil are charged to the income statement in the period in which they are incurred. Production costs include movements in underlift and overlift balances.

Depletion costs

Oil and gas properties are depreciated from the commencement of production, on a UoP basis, which is the ratio of oil and gas production in the period to the estimated quantities of the 2P reserves at the end of the period plus the production in the period, on a field-by-field basis. Facilities included in oil and gas production assets are depreciated on a UoP basis over the economic useful life of the field concerned. Costs used in the UoP calculation comprise the net carrying amount of capitalized costs plus the estimated future field development costs. Changes in the estimates of reserves or future field development costs are dealt with prospectively. Oil and gas volumes are considered produced once they have been measured through meters at custody transfer or sales transaction points at the outlet valve on the field storage tank. Rights and concessions are depleted on the UoP basis over the total proved and probable reserves of the relevant area.

NOTES TO INTERIM CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - CONTINUED

Derivative financial instruments and hedge accounting

The Group is exposed to certain risks relating to its ongoing business operations. The primary risk managed using derivative instruments is commodity price risk.

The Group uses forward commodity contracts to hedge its commodity price risk. On the forward commodity contracts hedge accounting is not considered applicable as the own-use exception applies: the Group does not enter into physical oil contracts other than to meet the Group's expected sales requirements. These arrangements therefore fall outside the scope of IFRS 9 and are classified as normal sales contracts that are accounted for on an accrual basis.

The Group's derivative financial instruments are initially recognized at fair value on the date on which the derivative contracts are entered into and are subsequently remeasured at fair value, with subsequent changes in fair value recognized in other comprehensive income. Derivatives are carried as financial assets when the fair value is positive and as financial liabilities when the fair value is negative.

Inventories

Inventories mainly comprise materials. These are stated at the lower of cost and net realizable value. Purchase cost includes costs of bringing material inventory to their present location and condition, including freight and handling charges. Cost is determined using the weighted average method. Net realizable value is the estimated selling price in the ordinary course of business, less selling expenses.

If carrying value exceeds the net realizable amount, a write down is recognized. The write-down may be reversed in a subsequent period if the circumstances which caused it no longer exist.

Trade receivables

Trade receivables are amounts due from customers for crude oil and gas sold or services performed in the ordinary course of business and represent the Group's right to an amount of consideration that is unconditional (i.e., only the passage of time is required before payment of the consideration is due). Trade receivables are recognized initially at fair value and subsequently measured at amortized cost using the effective interest method, less any allowance for expected credit losses.

Dividends

Dividend liabilities are recognized when the Company's shareholders have the right to receive the payment when the dividend is approved by the Board of Directors of the Company.

New accounting standards

On January 1, 2025, the Company adopted the amendments to IAS 21 - Lack of Exchangeability. The amendments help entities to determine whether a currency is exchangeable into another currency, and which spot exchange rate to use when it is not. There was no material impact to the Company's financial statements.

On April 9, 2024, the International Accounting Standards Board (IASB) issued IFRS 18 Presentation and Disclosure in Financial Statements, which aims to improve how companies communicate their financial statements, with a focus on information about financial performance in the statement of profit or loss. IFRS 18 is effective January 1, 2027. The Company is in the process of assessing the impact that the standard will have on its financial statements.

Other new accounting standards and amendments to accounting standards have been published that are not mandatory for March 31, 2025, reporting periods and have not been early adopted by the Company. These are as follows:

- Amendments to the Classification and Measurement of Financial Instruments – Amendments to IFRS 9 and IFRS 7 (effective for annual periods beginning on or after 1 January 2026);
- Annual improvements to IFRSs: Volume 11 (effective for annual periods beginning on or after 1 January 2026);
- IFRS 19 Subsidiaries without Public Accountability: Disclosures (effective for annual periods beginning on or after 1 January 2027); and

These amendments are not expected to have a material impact on the entity in the current or future reporting periods and on foreseeable future transactions.

NOTES TO INTERIM CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - CONTINUED

4. Business combination:

On March 19, 2025, the Company completed the transaction with BTG Oil & Gas to consolidate its interest in Prime. The transaction was originally announced on June 24, 2024. The acquisition increased the Company's ownership in core cash generating assets and brought in a new, strategically aligned cornerstone investor, BTG Pactual. It is also expected to enable enhanced shareholder returns and the creation of a materially stronger growth proposition. The acquisition was completed by way of amalgamation whereby BTG Oil & Gas exchanged its 50 percent interest in Prime, held through its fully owned subsidiary BTG Pactual Holding S.à.r.l., in exchange for 239,828,655 newly issued shares in the Company. The primary assets acquired are an indirect 8% interest in Petroleum Mining License ("PML") 52 and an indirect 16% interest in PMLs 2, 3 and 4 as well as Petroleum Prospecting License ("PPL") 261. PML 52 is operated by affiliates of Chevron and covers part of the producing Agbami field. PMLs 2, 3 and 4 and PPL 261 are operated by affiliates of TotalEnergies and contain the producing Akpo and Egina fields.

The acquisition date for accounting purposes corresponds to the completion of the transaction on March 19, 2025. The acquisition is regarded as a business combination and has been accounted for using the acquisition method of accounting in accordance with IFRS 3. A purchase price allocation ("PPA") has been performed to allocate the consideration to fair value of assets acquired and liabilities assumed. The PPA is performed as of the acquisition date. The closing share price of CAD 2.09 and closing USD/CAD currency exchange rate of 1.4193 on March 19, 2025, were used as a basis for measuring the value of the consideration, as set forth below, and includes the Company's previously held 50% interest in Prime prior to March 19, 2025.

Expressed in millions of United States dollars	
Value of share consideration to BTG Oil & Gas	353.2
Value of previous interest held in Prime	327.8
Total value of consideration	681.0

Each identifiable asset and liability is measured at its acquisition date fair value based on guidance in IFRS 13. Trade receivables are recognized at gross contractual amounts due, as they relate to large and credit-worthy customers. Historically, there has been no significant uncollectible trade receivables in Prime.

The recognized amounts of assets and liabilities assumed as at the date of acquisition were as follows.

Preliminary purchase price allocation

	March 19, 2025
Assets acquired	
Oil and gas properties	1,476.2
Inventories	95.4
Indemnity asset (note 14)	21.6
Trade and other receivables	233.5
Cash and cash equivalents [(1)]	380.4
Total assets acquired	**2,207.1**
Liabilities assumed	
Non-current financial liabilities	451.5
Non-current provisions	165.4
Deferred tax liabilities	343.3
Current financial liabilities	298.5
Trade and other payables	164.6
Current tax liabilities	48.2
Current provisions (note 14)	54.6
Total liabilities assumed	**1,526.1**
Net assets and liabilities recognized	**681.0**
Value of share consideration to BTG Oil & Gas	353.2
Value of previously held interest in Prime (note 7)	327.8
Total value of consideration	**681.0**

(1) Cash and cash equivalents includes $59.1 million of cash held in the amalgamated company.

NOTES TO INTERIM CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - CONTINUED

In the period from the acquisition date to March 31, 2025, the revenue and profit included in the interim condensed consolidated statement of net income and comprehensive income relating to the acquired entities was $76.4 million and $7.0 million respectively. Acquisition-related costs for the year ended December 31, 2024, and the three months ended March 31, 2025, were included in general and administrative expenses and amounted to $6.9 million and $7.6 million, respectively.

If the acquisition had taken place on January 1, 2025, the estimated revenue and profit of the combined Group for the three months ended March 31, 2025, would have been approximately $399.9 million and $25.9 million respectively. These figures may not be indicative of the results that would have been achieved if the acquisition had actually taken place on January 1, 2025.

The purchase price allocation above is preliminary and based on current available information about fair values as of the acquisition date. If new information becomes available within 12 months from the acquisition date, the Group may change the fair value assessment in the PPA, in accordance with guidance in IFRS 3.

5. Oil and gas properties:

	Nigeria
At January 1, 2025	-
Acquired under amalgamation	1,476.2
Remeasurement of site restoration provisions	122.9
Additions	1.8
Depletion	(12.1)
At March 31, 2025	1,588.8

As at March 31, 2025, oil and gas properties amounted to $1,588.8 million and related to the licenses PML 52 (covering part of the Agbami field), PML 2 (Akpo field), PML 3 (Egina field) and PML 4 (Preowei Field) in Nigeria.

The Company recognized a change in estimate of $122.9 million in oil and gas properties relating to the remeasurement of the site restoration provisions acquired under the amalgamation in accordance with IAS 37 (see note 14).

6. Intangible exploration assets:

	Equatorial Guinea	South Africa	Total
At January 1, 2024	13.4	5.7	19.1
Additions	4.5	5.7	10.2
At December 31, 2024	17.9	11.4	29.3
Additions	1.7	8.0	9.7
At March 31, 2025	19.6	19.4	39.0

As at March 31, 2025, the carrying amount of the Company's intangible exploration assets in Equatorial Guinea was $19.6 million and related to its 80% interest in Blocks EG-18 and EG-31 (as at December 31, 2024 – $17.9 million).

As at March 31, 2025, the carrying amount of the Company's intangible exploration assets in South Africa was $19.4 million for its 18.0% (as at December 31, 2024 – 17.0%) participating interest in the Block 3B/4B Exploration Right (as at December 31, 2024 - $11.4 million).

On July 26, 2024, the Company signed an agreement with Eco to acquire an additional 1.0% interest in Block 3B/4B from Azinam Limited, Eco's wholly owned subsidiary, in exchange for all common shares and warrants over common shares held by the Company in Eco. On January 13, 2025, the Company announced that it had completed this transaction. The Company's interest in Block 3B/4B increased by 1.0% to 18.0% and the Company ceased to be a shareholder in Eco. The fair value of the Company's investment in Eco on the day of the transaction was $8.0 million which has been recorded as an addition to oil and gas properties.

NOTES TO INTERIM CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - CONTINUED

7. Equity investment in joint venture:

Prime Oil and Gas Coöperatief U.A. ("Prime"):

On March 19, 2025, the Company announced the completion of the amalgamation with BTG Oil & Gas ("the amalgamation) to consolidate the remaining 50% interest in Prime in exchange for 239,828,655 common shares issued in Africa Oil. Following completion of the amalgamation, Prime is fully consolidated by the Company as from March 19, 2025 (see Note 4).

The following table shows the Company's carrying value of the non-controlling 50% interest in Prime as at March 31, 2025, and December 31, 2024. The carrying value as per March 19, 2025, of $327.8 million has been assigned to the fair value of assets acquired and liabilities assumed as per Note 4.

	March 31, 2025	December 31, 2024
Balance, beginning of the period	328.4	572.5
Share of joint venture profit	15.9	226.0
Distributions received from Prime	(60.0)	(36.0)
Revaluation of contingent consideration	0.6	2.6
Reversal of impairment / (Impairment)	42.9	(436.7)
Impact of amalgamation	(327.8)	-
Balance, end of the period	-	328.4

In the three months ended March 31, 2025, the Company recognized an income of $15.9 million, relating to its investment in Prime up to March 19, 2025 (three months ended March 31, 2024 - $21.5 million).

In the three months ended March 31, 2025, Prime made one distribution of $120.0 million gross, with a net payment to the Company of $60.0 million. In the three months ended March 31, 2024, Prime made no distributions.

As at December 31, 2024, management determined there was an objective evidence of impairment in relation to the Company's shareholding in Prime as a result of the significant decrease in the Africa Oil share price between June 24, 2024, when the Company announced the Proposed Reorganization and December 31, 2024. The fair value of the 50% shareholding in Prime decreased as the fair value considers the number of Africa Oil shares that were agreed in relation to the purchase of the additional interest in Prime and the trading value of Africa Oil shares, as this is an observable fair value input under IFRS Accounting Standards. As at December 31, 2024, the fair value of the Company's existing shareholding in Prime was calculated to be $328.4 million based on the implied value of the Proposed Reorganization, resulting in a non-cash impairment loss on the investment in Prime of $436.7 million for the year ended December 31, 2024. As at March 19, 2025, management determined there was an objective evidence of impairment reversal based on the Africa Oil share price when the Company announced the completion of the amalgamation. The fair value of the 50% shareholding in Prime was calculated to be $327.8 million, resulting in a non-cash impairment reversal on the investment in Prime of $42.9 million for the three months ended March 31, 2025.

The following tables summarizes Prime's financial information for the period up to and including March 19, 2025, and the three months ended March 31, 2024. Following completion of the amalgamation on March 19, 2025, Prime is fully consolidated by the Company.

NOTES TO INTERIM CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - CONTINUED

Prime's Statement of Net Income and Comprehensive Income

Period and three months ended	March 19, 2025	March 31, 2024 [1]
Revenue	323.5	176.6
Cost of Sales		
Production costs [2]	(187.4)	16.0
Depletion costs	(71.3)	(96.7)
	(258.7)	(80.7)
Gross profit	64.8	95.9
General and administrative expenses	(6.2)	(3.7)
Operating profit	58.6	92.2
Finance income	2.4	2.0
Finance expense [3]	(21.3)	(30.0)
Net financial items	(18.9)	(28.0)
Profit before tax	39.7	64.2
Income tax	(7.9)	(21.2)
Net income and comprehensive income for the period	31.8	43.0
Proportionate share of Prime's profit and comprehensive income for the period	31.8	43.0
Proportionate share of Prime's net income	15.9	21.5

(1) Certain comparative figures have been reclassified to conform with the presentation of the Company's Interim Condensed Consolidated Statement of Net Income and Comprehensive Income following completion of the amalgamation.

(2) As at March 19, 2025, Prime was in a lower net underlift position compared to December 31, 2024. This resulted in a loss of $133.1 million in the Statement of Net Income and Comprehensive Income for the period ended March 19, 2025 (three months ended March 31, 2024 – income of $76.2 million) included in production costs.

(3) Finance expense is primarily made up of interest expenses incurred on external facilities and accretion expenses incurred on the decommissioning liability. Finance costs for the period ended March 19, 2025, also included a $3.7 million accounting loss on a purchased Asian put option and a zero-premium Asian Dated Brent Collar (three months ended March 31, 2024 – $6.3m accounting loss on a purchased Asian put option).

NOTES TO INTERIM CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - CONTINUED

Supplementary information: Prime's Statement of Cash Flows

Period and three months ended	March 19, 2025	March 31, 2024 (1)
Cash flows generated by/ (used in)		
Profit before tax	39.7	64.2
Adjustments for:		
Depletion costs	71.3	96.7
Net financial items	18.9	28.0
Taxes	(30.2)	(34.8)
Other	(1.0)	(1.9)
Cash generated from operating activities before working capital	98.7	152.2
Changes in working capital	(25.7)	11.2
Net cash generated from operating activities	73.0	163.4
Expenditures on oil and gas properties	(22.6)	(31.1)
Interest income received	2.2	2.0
Net cash used in investing activities	(20.4)	(29.1)
Distributions paid to shareholders	(120.0)	-
Interest expense paid	(10.8)	(17.9)
Net cash used in financing activities	(130.8)	(17.9)
Foreign exchange variation on cash and cash equivalents	-	-
Total cash flow	(78.2)	116.4
Cash and cash equivalents, beginning of the period	399.5	152.2
Cash and cash equivalents, end of the period	321.3	268.6

(1) Certain comparative figures have been reclassified to conform with the presentation of the Company's Interim Condensed Consolidated Statement of Cash Flows following completion of the amalgamation.

NOTES TO INTERIM CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - CONTINUED

8. Equity investments in associates:

The Company holds the following equity investments in associates:

	Africa Energy Corp.	Eco (Atlantic) Oil and Gas Ltd	Impact Oil and Gas Ltd	Total
Shares held at March 31, 2025	276,982,414	-	449,464,396	
Ownership at March 31, 2025	11.6%	-	39.5%	
At January 1, 2024	24.8	7.6	102.3	**134.7**
Share of loss from equity investments	(42.1)	(0.6)	(16.1)	**(58.8)**
Reversal of impairment of equity investments	20.1	-	-	**20.1**
Additional investments	-	-	88.6	**88.6**
Reclassification to Investment held for sale	-	(7.0)	-	**(7.0)**
At December 31, 2024	2.8	-	174.8	**177.6**
Share of loss from equity investments	(0.4)	-	(1.6)	**(2.0)**
Loss on dilution of equity investments	(0.9)	-	-	**(0.9)**
Distribution received	-	-	(31.6)	**(31.6)**
At March 31, 2025	1.5	-	141.6	**143.1**

In the three months ended March 31, 2025, the Company recognized a loss of $2.9 million (three months ended March 31, 2024 – loss of $14.3 million). The Company also recognized a gain of $0.9 million in the three months ended March 31, 2025, on the shares in Eco (Atlantic) Oil and Gas Ltd classified as Investment held for sale, resulting in a total loss from investments in associates of $2.0 million in the three months ended March 31, 2025.

As at March 31, 2025, the Company determined that there were no indicators of impairment for its investments in Africa Energy Corp. or Impact Oil and Gas Ltd.

A. Africa Energy Corp. ("Africa Energy"):

Africa Energy is an oil and gas exploration company with an interest in South Africa.

As at March 31, 2025, the market value of the Company's investment in Africa Energy was $7.0 million based on the share price of CAD 0.035 (as at December 31, 2024 - $5.8 million). The carrying value is less than the market value from significant impairments recognized by Africa Energy.

On March 31, 2025, Africa Energy announced the closing of a private placement of common shares, including the issue of common shares for debt. Africa Oil did not participate in this private placement and as a result its shareholding in Africa Energy has been reduced from 19.67% as at December 31, 2024, to 11.56% as at the date hereof.

B. Eco (Atlantic) Oil and Gas Ltd. ("Eco"):

On July 26, 2024, the Company signed an agreement with Eco to acquire an additional 1.0% interest in Block 3B/4B from Azinam Limited, Eco's wholly owned subsidiary, in exchange for all common shares and warrants over common shares held by the Company in Eco. Following the announcement of this transaction, the investment in Eco was reclassified to an investment held for sale (see note 10). On January 13, 2025, the Company announced the completion of this transaction.

C. Impact Oil and Gas Ltd ("Impact"):

Impact is an oil and gas exploration company with interests in Namibia and South Africa.

On January 10, 2024, the Company announced a strategic farmout agreement between its investee company Impact, and TotalEnergies, that allows the Company to continue its participation in the Venus oil development project and the follow-on exploration and appraisal campaign on Blocks 2913B and 2912 with no upfront costs. At the date hereof, Impact has a 9.5% interest in Blocks 2912 and 2913B that is fully carried for all joint venture costs, with no cap, through to first commercial production. This agreement provides Impact with a full interest-free carry loan over all of Impact's remaining development, appraisal and exploration costs on the Blocks from January 1, 2024 ("Effective Date"), until the date on which Impact receives the first sales proceeds from oil production on the Blocks ("First Oil Date"). On and from the First Oil Date, the carry is repayable to TotalEnergies in kind from 60% of Impact's after-tax cash flow, net of all joint venture costs, including capital expenditures. During the repayment of the carry, Impact will pool its entitlement barrels with those of TotalEnergies for more regular off-takes and a more stable cashflow profile and will also benefit from TotalEnergies' marketing and sales capabilities.

On January 29, 2025, Impact distributed $31.6 million net to the Company's shareholding.

NOTES TO INTERIM CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - CONTINUED

9. Inventories:

Inventories relate to well supplies and operational spare parts to be used in the oil production process in Nigeria.

10. Investment held for sale:

On July 26, 2024, the Company signed an agreement with Eco to acquire an additional 1.0% interest in Block 3B/4B from Azinam Limited, Eco's wholly owned subsidiary, in exchange for all common shares and warrants over common shares held by the Company in Eco. Following the announcement of this transaction, the investment in Eco was reclassified to an investment held for sale. On January 13, 2025, the Company announced the completion of this transaction with the result that the Company is no longer a shareholder in Eco.

11. Trade and other receivables:

	March 31, 2025	December 31, 2024
Trade receivables	156.2	-
Underlift position	10.5	-
Short-term receivables with partners	16.2	-
Prepaid expenses and accrued income	2.5	2.4
Other receivables	26.5	1.6
Total accounts receivable and prepaid expenses	211.9	4.0

Other receivables includes an indemnity asset of $21.6 million recognized under the deed of indemnity entered into between the Company and BTG Oil & Gas (see note 14).

12. Cash and cash equivalents:

Cash and cash equivalents include short-term deposits made for varying periods of between one day and three months, depending on the immediate cash requirements of the Group, and earn interest at varying rates.

13. Share capital:

A. The Company is authorized to issue an unlimited number of common shares with no par value.

B. Issued:

	March 31, 2025		December 31, 2024	
	Shares	Amount	Shares	Amount
Balance, beginning of the period	439,078,170	1,195.8	463,831,871	1,265.3
Share issuance to BTG Oil & Gas under amalgamation Agreement	239,828,655	353.2	-	-
Exercise of Share Options	-	-	647,000	0.5
Settlement of Restricted Share Units	836,323	1.1	271,063	0.5
Settlement of Performance Share Units	1,106,332	1.5	577,968	1.1
Cancellation of shares repurchased	(6,176,053)	(16.8)	(26,249,732)	(71.6)
Balance, end of the period	674,673,427	1,534.8	439,078,170	1,195.8

The Company launched a share buyback program on December 6, 2023, that ended on December 5, 2024. During the year ended December 31, 2024, a total of 24.0 million Africa Oil common shares were repurchased and cancelled under this share buyback program. The Company launched a new share buyback program on December 6, 2024, under which 2.5 million Africa Oil common shares were repurchased during the year ended December 31, 2024, of which 2.2 million Africa Oil common shares were cancelled during the year ended December 31, 2024. In the three months ended March 31, 2025, a total of 5.9 million Africa Oil common shares were repurchased and 6.2 million Africa Oil common shares were cancelled during the three months ended March 31, 2025.

NOTES TO INTERIM CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - CONTINUED

The balance of share capital has been reduced by determining the average per-share amounts in the share capital account, before cancellation of shares repurchased, and applying this to the numbers of shares cancelled. The difference between the reduction in share capital and the amount paid for shares repurchased has been added to the balance of contributed surplus.

In the three months ended March 31, 2025, the Board of Directors approved a dividend of $0.0371 per share which was declared in March 2025 and paid in April 2025 for a total amount of approximately $25.0 million.

14. Provisions:

	Site restoration	Contingent consideration	Share-based compensation	Others	Total
At 1 January 2024	5.5	37.8	14.1	-	57.4
Charges	-	-	1.5	-	1.5
Unwinding of discount	0.2	2.6	-	-	2.8
Settlements	-	-	(8.3)	-	(8.3)
At December 31, 2024	5.7	40.4	7.3	-	53.4
Acquired under amalgamation	162.6	54.6	-	2.8	220.0
Changes in estimates	122.9	-	-	-	122.9
Charges	-	-	4.0	-	4.0
Unwinding of discount	0.4	0.7	-	-	1.1
Settlements	-	-	(6.0)	-	(6.0)
At March 31, 2025	291.6	95.7	5.3	2.8	395.4
Non-current	291.6	-	1.1	2.8	295.5
Current	-	95.7	4.2	-	99.9
Total at March 31, 2025	291.6	95.7	5.3	2.8	395.4
Non-current	5.7	40.4	3.1	-	49.2
Current	-	-	4.2	-	4.2
Total at December 31, 2024	5.7	40.4	7.3	-	53.4

A. Site restoration

The provision for site restoration amounted to $291.6 million as per March 31, 2025 (as at December 31, 2024 - $5.7 million). The fair value of the provision for site restoration mainly relates to Nigeria and was based on the estimated future cash flows to decommission the oil and gas properties at the end of their useful life. The discount rate used to determine the net present value of the decommissioning obligation was between 4.2% and 4.6% (as at December 31, 2024 – 3.5%) based on a risk-free rate with a similar maturity to that of the timing of the expected cash flows and a long-term inflation rate of 2.2% (as at December 31, 2024 – 2%).

The site restoration provisions acquired under the amalgamation represents the present value of decommissioning costs relating to the acquired oil and gas properties, which are expected to be incurred up to the economic cut-off dates of the Agbami, Akpo and Egina fields. These provisions have been calculated based on the cash flow estimates as provided by the operators of the fields. The fair value of the site restoration provisions acquired on amalgamation totalling $162.6 million have been calculated using a credit-adjusted discount rate in accordance with IFRS 3, which has subsequently been re-measured using a risk-free rate in accordance with IAS 37 resulting in a change in estimate of $122.9 million.

B. Contingent consideration

Under the Prime Sale and Purchase Agreement completed on January 14, 2020, a deferred payment of $118.0 million, subject to adjustment, may be due to the seller contingent upon the timing of the final PML 52 tract participation in the Agbami field. The signing of the Securitization Agreement by Prime in 2021 led to the Company reassessing its view of the likelihood of making a contingent consideration payment to the seller. The signing of the Securitization Agreement by Prime does not constitute a redetermination of the tract participation and therefore does not trigger the payment of a contingent consideration under the Sale and Purchase Agreement but, at the Company's discretion, could trigger discussions with the seller. The outcome of this process is uncertain. In 2021, the Company recorded $32.0 million as contingent consideration and increased this to $40.4 million as at December 31, 2024, and to $41.1 million in the three months ended March 31, 2025. The deferred payment is due in the three months ended March 31, 2026, and has been reclassified to short term provisions in the three months ended March 31, 2025.

NOTES TO INTERIM CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - CONTINUED

On June 25, 2021, Prime 127 Nigeria Limited ("Prime 127"), a subsidiary of Prime, signed a securitization agreement with two of the unit parties, Equinor and Chevron (the "Securitization Agreement"), whereby Equinor agreed to pay a security deposit to the two other JV parties to secure future payments due under that Securitization Agreement, pending a comprehensive resolution being reached among all unit parties in respect of the tract participation in the Agbami field by December 27, 2024. In accordance with the Securitization Agreement, on June 29, 2021, Prime 127 received from Equinor its portion of the security deposit in the form of a cash payment of $305.3 million. Prime 127 received an additional payment of $24.4 million on January 31, 2025, pursuant to the Securitization Agreement. Given no comprehensive resolution was reached by December 27, 2024, Prime 127 has recognized its portion of the security deposit and the additional receivable under the Securitization Agreement as other operating income on December 27, 2024. The parties will continue discussions to seek final resolution of the formal redetermination of the Agbami tract participation in respect of the period after December 27, 2024, however there is no certainty that such ongoing discussions will result in a final resolution.

Under the amended joint sale agreement between (among others) BTG Holding and the seller dated October 31, 2018, the seller could potentially claim that, given an additional payment has been received under the securitization agreement, this triggers a payment obligation of $54.6 million, exclusive of interest, capital taxes and certain deductions, contingent upon various criteria, with the outcome of this potential claim uncertain. Management considers the likelihood of any interest being payable to be unlikely. The Company has recorded an indemnity asset of $21.6 million under the deed of indemnity entered into between a subsidiary of the Company and BTG Oil & Gas for any costs suffered or incurred above $33.0 million post completion of the amalgamation, with the deed of indemnity backed by a $22.0 million letter of credit granted in favour a subsidiary of the Company. The letter of credit will remain in place for an initial period of two years and if a claim is not resolved in two years or is made after the two year period BTG Oil & Gas has undertaken to extend or reinstate the letter of credit.

15. Financial liabilities:

	Reserves Based Lending Facility	Lease Liability	Total
At 1 January 2024	-	-	-
Initial recognition of IFRS 16 lease liability	-	3.7	3.7
Repayments	-	(0.4)	(0.4)
At December 31, 2024	-	3.3	3.3
Acquired under amalgamation	750.0	-	750.0
Repayments	(130.0)	(0.1)	(130.1)
At March 31, 2025	620.0	3.2	623.2
Non-current	406.3	2.5	408.8
Current	213.7	0.7	214.4
Total at March 31, 2025	620.0	3.2	623.2
Non-current	-	2.6	2.6
Current	-	0.7	0.7
Total at December 31, 2024	-	3.3	3.3

A. Reserves Based Lending Facility

On amalgamation the Company acquired a Reserves Based Lending Facility ("RBL"). The total amount that can be drawn under the RBL is limited to the Borrowing Base Amount ("BBA"), which is subject to redeterminations on March 31 and September 30 of each year, limited by aggregate commitments. As of March 31, 2025, the BBA was $720.0 million, which will amortize as the RBL moves towards final maturity.

The principal bears interest at Term SOFR + 4.00% until June 2025, then Term SOFR + 4.25% until June 2027, then Term SOFR + 4.50% until final maturity on January 1, 2029. In addition, commitment fees of 40% of the margin are payable on the undrawn but available portion of the RBL, and commitment fees of 20% of the margin are payable on the unavailable portion of the RBL.

The RBL perimeter remains at the Prime level - Prime is the borrower, and Prime 127 Nigeria Limited and Prime 130 Nigeria Limited are the guarantors. The main security package is comprised of security over the shares, production assets, contracts and rights of the Nigerian entities - Prime 127 and Prime 130. In addition, RBL lenders have security over cash and cash equivalents held in project accounts, receivables against cargos sold and all relevant insurance policies of the three Prime entities.

All financial and liquidity covenants covered the RBL are restricted to these three entities. The Prime entities shall ensure that total net debt to adjusted EBITDAX on each quarter is no greater than 3.0:1, that the historic debt service cover ratio for the preceding year is greater than 1.20:1, and that on each quarter of each year during each of the four successive quarters there are or will be sufficient funds available to the group to meet all relevant expenditure to be incurred in each of these four successive quarters as they fall due. The Company has been in compliance with the covenants in the three months ended March 31, 2025.

In case the BBA would reduce to an amount below the outstanding RBL balance, the Company would be required to repay the difference immediately.

NOTES TO INTERIM CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - CONTINUED

B. Corporate Facility

On May 21, 2024, the Company amended its existing Corporate Facility. At any point before Prime refinances its debt, the availability under the Corporate Facility will now be $65.0 million until June 30, 2025, $43.0 million from July 1, 2025, until June 30, 2026, and $22.0 million from July 1, 2026, to May 21, 2027, i.e. its new final maturity date. After Prime refinances its debt, the availability under the Corporate Facility will be $125.0 million until June 30, 2026, and $63.0 million from July 1, 2026, until May 21, 2027. Commitment fees of 40% of the margin are payable on the undrawn available portion of the Corporate Facility and commitment fees of 15% of the margin are payable on the unavailable portion of the Corporate Facility. The Corporate Facility carries interest of 1 month-SOFR plus a margin of 6.5% in the first year from May 21, 2024, 7.0% in the second year and 7.5% in the third year.

The Company provided security in respect of the Corporate Facility mainly in the form of a share pledge over the shares of PetroVida (which holds 50% of Prime), and a charge over the bank account into which the Prime distributions are paid.

The Corporate Facility is subject to financial and liquidity covenants. The Company shall ensure that total net debt to adjusted EBITDAX on June 30 and December 31 of each year is no greater than 3.0:1, the FLCR ratio on March 31 and September 30 of each year is not less than 1.1:1 and that from March 31 and September 30 of each year during each of the four successive quarters there are or will be sufficient funds available to the group to meet all relevant expenditure to be incurred in each of these four successive quarters as they fall due. The Company has been in compliance with the covenants in the three months ended March 31, 2025.

16. Trade and other payables:

	March 31, 2025	December 31, 2024
Short-term payables with partners	115.6	-
Crude oil overlift payable	20.0	-
Accruals	21.9	7.7
Other payables	4.9	2.0
Total trade and other payables	162.4	9.7

17. Dividends payable:

On March 20, 2025, the Company declared the first quarterly dividend of approximately $25.0 million or $0.0371 per share with payments made to shareholders during April 2025.

18. Commitments and contingencies:

A. Investment in Prime:

Under the Prime Sale and Purchase Agreement completed on January 14, 2020, a deferred payment of $118.0 million, subject to adjustment, may be due to the seller contingent upon the timing of the final PML 52 tract participation in the Agbami field. The signing of the Securitization Agreement by Prime in 2021 led to the Company reassessing its view of the likelihood of making a contingent consideration payment to the seller. The signing of the Securitization Agreement by Prime does not constitute a redetermination of the tract participation and therefore does not trigger the payment of a contingent consideration under the Sale and Purchase Agreement but, at the Company's discretion, could trigger discussions with the seller. The outcome of this process is uncertain. In 2021, the Company recorded $32.0 million as contingent consideration and increased this to $40.4 million as at December 31, 2024, and to $41.1 million in the three months ended March 31, 2025.

B. Withdrawal from Kenya:

On May 23, 2023, the Kenya entities along with TotalEnergies submitted withdrawal notices to the remaining joint venture party on Blocks 10BB, 13T and 10BA in Kenya, to unconditionally and irrevocably, withdraw from the entirety of the JOAs and PSCs for these concessions. The Company concurrently submitted notices to Ministry of Energy and Petroleum, requesting the government's consent to transfer all of its rights and future obligations under the PSCs to its remaining joint venture party. Government consent to the transfer remained outstanding as at March 31, 2025. In accordance with the JOA and PSC the Company retains economic participation for activities prior to June 30, 2023, which might result in additional costs for the Company. The Company continues to monitor the claim made against the operator by local communities in relation to past operations which may relate to the period prior to June 30, 2023. No provision has been recognized for this as at March 31, 2025.

C. Securities and guarantees

Under the conditions of the RBL facility, the main security package is comprised of security over the shares, production assets, contracts and rights of the Nigerian entities Prime 127 and Prime 130, cash and cash equivalents in the amount of $234.7 million as per March 31, 2025, that are held within the projects accounts in Nigeria and The Netherlands, proceeds from the oil cargos sold and proceeds from the intercompany receivables between the Company and the Nigerian entities. Further, any and all claims relating to, and all returns of premium in respect of, all relevant insurance policies have been secured.

NOTES TO INTERIM CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - CONTINUED

D. Commitments from forward sales

The Group uses a mix of financial derivatives and physical forward sales contracts to manage its commodity price risk and ensure stability in cash flows. Its strategy is to hedge approximately 50-70% of its next 12-months' scheduled cargos. As at March 31, 2025, four cargos of the Group's expected lifted entitlement production for the remainder of 2025 are covered by forward contracts. The average cargo lifted is for 1 million barrels of oil. The Group's triggers for the four cargos covered by forward contracts have been triggered in April 2025 at an average of $64 per barrel.

19. Segment information:

The Group operates within several geographical areas. All revenue and therefore gross profit as reported by the Company is currently derived from operations in Nigeria.

For segment information about oil and gas properties and intangible exploration assets, see Note 5 and 6.

20. Revenue:

Revenue for the three months ended March 31, 2025, and March 31, 2024, is comprised of the following:

For the three months ended	March 31, 2025	March 31, 2024
Oil revenue	75.7	-
Gas revenue	0.7	-
Total revenue	76.4	-

21. Production costs:

Production costs for the three months ended March 31, 2025, and March 31, 2024, is comprised of the following:

For the three months ended	March 31, 2025	March 31, 2024
Cost of operations	7.4	-
Movements on overlift/underlift balances	41.9	-
Royalties	1.5	-
Others	0.4	-
Total production costs	51.2	-

22. Finance income:

For the three months ended	March 31, 2025	March 31, 2024
Interest income on cash and cash equivalents	0.9	2.6
Interest income from associated companies	0.2	0.1
Total finance income	1.1	2.7

23. Finance expense:

For the three months ended	March 31, 2025	March 31, 2024
Interest expense on RBL	1.6	-
Commitment fees	0.6	1.1
Interest expense on lease liability	0.1	0.1
Unwinding of site restoration provision	0.5	0.1
Total finance expense	2.8	1.3

NOTES TO INTERIM CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - CONTINUED

24. Income tax:

For the three months ended	March 31, 2025	March 31, 2024
Current tax expense	16.0	-
Deferred tax income	(12.2)	-
Total income tax	3.8	-

The current tax expense includes corporate income tax, an Education Tax which is imposed on every Nigerian company at a rate of 3.0% of the assessable profit, a Naseni ("National Agency for Science and Engineering Infrastructure') Levy that is imposed in Nigeria based on 0.25% of profits before tax and a Police Fund Levy, based on 0.005% of net profit.

25. Net income per share:

For the three months ended	March 31, 2025			March 31,2024		
		Weighted Average			Weighted Average	
	Net income	Number of shares	Per share amounts	Net income	Number of shares	Per share amounts
Basic income per share						
Net income attributable to common shareholders	50.9	468,472,433	0.11	3.5	460,990,598	0.01
Effect of dilutive securities	-	8,364,249	-	-	13,755,026	-
Dilutive income per share	50.9	476,836,682	0.11	3.5	474,745,624	0.01

In the three months ended March 31, 2025, the Company used an average market price of CAD $1.97 per share (three months ended March 31, 2024 – CAD $2.32) to calculate the dilutive effect of share purchase options. Dilutive securities include share purchase options, RSUs and PSUs as the inclusion of these reduces the net income per share. In the three months ended March 31, 2025, 172,123 options, 626,753 RSUs and 7,565,373 PSUs were anti-dilutive and were not included in the calculation of dilutive income per share (three months ended March 31, 2024, 500,255 options were anti-dilutive). PSU's are awarded a performance multiple ranging from nil to 200% which leads to an increase in the dilutive and anti-dilutive potential of these instruments.

26. Related party transactions:

A. Transactions with Africa Energy:

On December 19, 2022, Africa Energy announced that it had secured a $5.0 million promissory note of which $2.0 million was provided by the Company and the remaining by other parties. On November 7, 2023, the promissory note provided by the Company and other parties to Africa Energy was increased by $3.3 million with $1.5 million of the increase provided by the Company by the end of the year ended December 31, 2024. No funds were provided in the three months ended March 31, 2025, and $0.3 million was provided in the three months ended March 31, 2024. The note was unsecured and matured on March 31, 2025, when the principal and accrued interest was repaid by Africa Energy in full. The note carried an annual interest rate of 15%. In the three months ended March 31, 2025, interest on the note amounted to $0.2 million (three months ended March 31, 2024 - $0.1 million).

B. Transactions with Eco:

On July 26, 2024, the Company signed an agreement with Eco to acquire an additional 1.0% interest in Block 3B/4B from Azinam Limited, Eco's wholly owned subsidiary, in exchange for all common shares and warrants over common shares held by the Company in Eco. On January 13, 2025, the Company announced that it had completed this transaction. The Company's interest in Block 3B/4B increased by 1.0% to 18.0% and the Company ceased to be a shareholder in Eco. Africa Oil will benefit from the carry agreed between Eco, TotalEnergies and QatarEnergy for this incremental interest.

C. Transactions with Impact:

On January 29, 2025, Impact distributed $31.6 million net to the Company's shareholding.

D. Transactions with BTG Oil & Gas:

The Company has recorded an indemnity asset of $21.6 million recognized under the deed of indemnity entered into between the Company and BTG Oil & Gas (see note 14).

27. Financial risk management:

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, appraisal and financing activities such as:

- credit risk;
- liquidity risk; and
- market risk.

This note presents information about the Company's exposure to each of the above risks, the Company's objectives, policies and processes for measuring and managing risk, and the Company's management of capital. Further quantitative disclosures are included throughout these interim condensed consolidated financial statements.

A. Credit risk:

Credit risk is the risk of loss if counterparties do not fulfill their contractual obligations. The majority of the Company's credit exposure relates to amounts due from the Company's joint venture parties and a credit facility with Africa Energy. The risk of the Company's joint venture parties 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 parties 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 and accounts receivable. As at March 31, 2025, the Company held $20.3 million (as at December 31, 2024 - $1.1 million) of cash in financial institutions outside of Canada, the Netherlands, Sweden and the UK. The Company also held $21.0 million (as at December 31, 2024 – $20.9 million) in short-term deposits in countries outside of Canada, the Netherlands and the UK with lending banks in the Corporate Facility with stable credit ratings.

B. 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 and development phase, require sufficient cash in order to fulfill their work commitments in accordance with contractual obligations, deliver stated shareholder returns, and to be able to potentially acquire strategic oil and gas assets.

The Company will potentially issue equity and debt and enter into farmout agreements with joint venture parties 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.

At March 31, 2025, the Company had $428.4 million of cash, $100.0 million of the RBL available and $65.0 million of the Corporate Facility available which provides the liquidity to fund operations and allows for increased liquidity if required for operations and acquisitions. The RBL matures on June 20, 2029, but amortizes each quarter as per the lower of commitments and the BBA. The Corporate Facility is available until May 21, 2027, and has a maturity of May 21, 2027 (see note 15).

The Company will also adjust the pace of its exploration and appraisal activities and any M&A activity to manage its liquidity position. The existing cash balance, the undrawn amounts under both facilities and cash flow from operations, are sufficient to fund the Company's obligations as they become due.

In relation to the amounts drawn under the RBL as at March 31, 2025, the Company has $100.4 million of liabilities that mature on September 30, 2025, based on the currently approved BBA profile, subject to the results of the next redetermination. A further $113.3 million will mature between six months and one year, $131.9 million will mature between one year and two years with the remaining balance of $274.4 million due between two and five years (as at December 31, 2024 – no maturities of its material contractual liabilities in excess of six months).

C. Market risk:

Market risk is the risk that changes in market prices, such as foreign exchange rates, interest rates, commodity prices and share prices, will affect the Company's income or the value of the financial instruments.

i. 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 to foreign currency exchange risk is mitigated by the fact that the Company sources the majority of its capital projects and expenditures in US dollars. The Company has not entered into any instruments to manage foreign exchange risk.

ii. Interest rate risk:

The RBL and Corporate Facility have a variable interest rate, that is referenced to SOFR and exposes the Company to interest rate risk when drawn.

iii. Commodity price risk:

The Company has a direct interest in three producing fields within PMLs 2, 3 and 52, all with significant levels of production. Its strategy is to hedge approximately 50-70% of its next 12-months' scheduled cargos. Physical sales are with counterparties including oil supermajors. The counterparties are part of groups with investment grade credit ratings.

NOTES TO INTERIM CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - CONTINUED

28. Subsequent events:

On May 14, 2025, the Company's Board has declared the second quarterly dividend in 2025 of approximately $25.0 million ($0.0371 per share) payable in June 2025 to shareholders of record at the close of business on May 26, 2025.

The Company reduced the RBL debt balance by $80.0 million and has commenced the process to cancel its $65.0 million Corporate Facility, which remains undrawn.

AFRICAOILCORP.COM