Meren

Meren Energy Inc. (previously called Africa Oil Corp.)

Management's Discussion and Analysis

For the Period Ended June 30, 2025

Q2

25

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.
	"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 Meren Coop, to reorganize and consolidate their respective 50:50 shareholdings in Meren Coop.
	"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.
G	"GHG"	means Greenhouse Gas.
H	"H1"	means first six months of the reporting period.
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.
	"Meren", "MER", or the "Company"	means Meren Energy Inc.
	"Meren Coop" or "Meren Coöperatief U.A."	means Meren Coöperatief U.A., previously known as Prime Coöperatief U.A., a company that holds interests in deepwater Nigeria production and development assets.
	"Meren Nigeria 52 Limited"	means Meren Nigeria 52 Limited (previously named Prime 127 Nigeria Limited).
	"Meren Nigeria 234 Limited"	means Meren 234 Nigeria Limited (previously named Prime 130 Nigeria Limited).
	"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.
	"PSA"	means Production 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 and six months ended June 30, 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 and six months ended June 30, 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"), including International Accounting Standard ("IAS") 34 Interim Financial Reporting.

This MD&A was reviewed and approved by the Board of Directors. The effective date of this MD&A is August 12, 2025.

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

The Company changed its name to Meren Energy Inc. on May 16, 2025, and was previously called Africa Oil Corp.

PROFILE AND STRATEGY

Meren 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 'MER'.

Meren'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 together with the Company's interests in Petroleum Prospecting Licenses ("PPLs") 261 and 2003.

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

H1 2025 AND POST PERIOD HIGHLIGHTS

- Declared the third 2025 quarterly dividend of approximately $25.0 million, bringing total distributions year-to-date to approximately $75.1 million.
- During Q2 2025:
  - Achieved average daily W.I. and entitlement production of 30,900 boepd and 35,700 boepd respectively, in line with expectations;
  - Two new Egina wells brought on stream in May, which are performing in line with expectations, and a successful well intervention in Akpo providing strong support to production performance;
  - Sold one cargo (approximately 1 MMbbl) at a sales price of $64.2/bbl;
  - Pro-actively reduced the RBL by $80.0 million, reducing interest expenses and ending Q2 2025 with a debt balance of $540.0 million;
  - Distributed the second quarterly cash dividend of approximately $25.1 million ($0.0371 per share) in June 2025;
  - End of Q2 2025 cash balance of $266.6 million, resulting in a net debt position of $273.4 million with a Net Debt/ EBITDAX of 0.6x as at June 30, 2025. RBL facility headroom of $94.1 million at the end of Q2 2025;
  - The Company cancelled its $65.0m Corporate Facility and the security has been released.
- During H1 2025:
  - Cashflow from operations before working capital adjustment of $177.5 million;
  - EBITDAX of $248.2 million;
  - Cash capital investments of $58.6 million.
- Post period end, the Company pro-actively reduced the RBL debt balance by a further $60.0 million in July 2025, resulting, as at the date hereof, in a debt balance of $480.0 million.

FINANCIAL SUMMARY (1)

		Three months ended		Six months ended		Year ended
	Unit	June 30, 2025	June 30, 2024	June 30, 2025	June 30, 2024	December 31, 2024
Meren highlights						
Net income/ (loss)	$'m	3.1	0.4	54.0	3.9	(279.1)
Net income/ (loss) per share - basic	*$/ share*	*0.00* (2)	*0.00*	*0.09* (2)	*0.01*	*(0.62)*
Net debt position (3)	$'m	273.4	444.5	273.4	444.5	289.1
WI production (3)	boepd	30,900	31,600	32,100	33,400	34,000
Entitlement production (3)	boepd	35,700	36,600	36,700	38,600	38,800
Cash flow from operations (4, 5)	$'m	77.7	n/a	177.5	n/a	n/a
EBITDAX (4)	$'m	106.6	n/a	248.2	n/a	n/a
Capital investments (4)	$'m	30.4	n/a	58.6	n/a	n/a

(1) The table includes non-GAAP measures. Definitions and reconciliations to these non-GAAP measures are provided on pages 13-16.

(2) Based on the weighted average number of shares outstanding for the three and six months period ended June 30, 2025, of 675,012,308 and 572,481,427 respectively, 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 Meren Coop to be comparable with net debt position and production numbers for the three and six months period ended June 30, 2025.

(4) Highlights are reported for the year 2025 only, on a constructed financial information basis, see pages 10 to 11 for further information.

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

HIGHLIGHTS AND OUTLOOK - CONTINUED

OUTLOOK

Shareholder Returns

The Company is pleased to announce that its Board has declared the distribution of the Company's third quarterly cash dividend in 2025 of approximately $25.0 million or $0.0371 per share. This dividend will be payable to shareholders of record at the close of business on August 20, 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 September 5, 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 September 10, 2025.

To execute the payment of the dividend, a temporary administrative cross border transfer closure will be applied by Euroclear from August 18, 2025, up to and including August 20, 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://mereninc.com/investor-summary/total-shareholder-returns/.

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

Nigeria

The Company continues working with its JV partners to optimise production performance across its three producing fields, Akpo, Egina and Agbami and progressing the Preowei development project towards the final investment decision.

The Company had previously guided to a break to the Akpo/Egina (PPL 2/3) drilling campaign in Q4 2025 to allow for the interpretation of the 4D seismic data and detailed results from the wells drilled to enhance the maturation of future infill well opportunities. This break has now been brought forward to Q3 2025, with drilling expected to resume in 2026 including the Akpo Far East near-field prospect and further development wells on Akpo and Egina fields.

Akpo Far East is an infrastructure-led exploration opportunity that in case of commercial discovery success, presents an attractive short cycle, high return investment opportunities that would benefit from the existing Akpo facilities. Akpo Far East prospect has 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.

The JV partners are continuing the project optimization work for the Preowei field with the aim of reaching a final investment decision. The results from a re-assessment of the Preowei seismic data are positive, indicating an increase in recoverable resources. Work to validate these results towards project optimization continue with technical workshops planned for Q3 2025.

For the Agbami field, in addition to the ongoing 2024 4D seismic interpretation, rig and long lead items contracting activities are progressing for the 2027 infill drilling campaign. Potential rig site visits have been concluded and the operator is scheduled to order the Long Lead Items ("LLIs") in Q3 2025.

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") facility with a capacity 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 Company through its shareholding in Impact has an effective 3.8 percent interest in the Venus project. This interest is fully funded through to first commercial production under an agreement between Impact and TotalEnergies, which covers all of Impact's share of development and exploration expenditures on these blocks from January 1, 2024, through to first commercial production from the Venus project.

The latest exploration drilling campaign was completed on April 25, 2025, with the drilling rig demobilized. Several further prospects are in the process of evaluation for drilling utilizing recently acquired 3D seismic data.

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.

The Company completed a strategic farm down agreement with TotalEnergies and QatarEnergy during Q3 2024 that provide it with exploration carry. 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.

Equatorial Guinea, Blocks EG-18 and EG-1

The Company continues to be in active dialogue with industry parties to attract farm in parties on both blocks, and the aspiration to complete the active data room part of the exercise by end Q3 2025 remains.

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 2027. However, there is no guarantee the Company can secure farminee partners on acceptable terms.

2025 MANAGEMENT GUIDANCE AND ACTUALS

The Company has revised its 2025 Management Guidance based on the H1 2025 actuals and the outlook for H2 2025, the changes are summarized in the table below. W.I. and entitlement production ranges have narrowed with mid-points for both ranges increasing marginally. EBITDAX and cash flow from operations guidance ranges are revised lower, mainly from a lower full-year average Dated Brent oil price estimate of $69/bbl, compared to the assumption of $75/bbl used for the original management guidance. The revised full-year oil price estimate of $69/bbl accounts for average Dated Brent price of $72/bbl for H1 2025 and an average Dated Brent price of $66/bbl for H2 2025.

	Original 2025 Guidance	Revised 2025 Guidance	H1 2025 Actuals
WI production (kboepd) (1)	28.0 - 33.0	30.0 - 33.0	32.1
Entitlement production (kboepd) (2)	32.0 - 37.0	34.5 - 37.5	36.7
EBITDAX ($ million) (3)	500 - 600	450 - 500	248.2
Cash flow from operations ($ million) (3)	320 - 370	260 - 310	177.5
Capital investments ($ million)	150 - 190	100 - 140	58.6

(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 June 30, 2025, are summarized in the following table:

Meren's Direct Working Interests (1,2)

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

Meren'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 Meren owns an 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 Meren owns a 32% WI. Meren'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 page 18.

BUSINESS UPDATE

SHAREHOLDER RETURNS

Pursuant to the Company's current Normal Course Issuer Bid ("NCIB") share repurchase program that was launched on December 6, 2024, Meren is authorized to repurchase through the facilities of the TSX, Nasdaq Stockholm and/or alternative Canadian trading systems, as and when considered advisable by Meren, 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 Meren. 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 Meren under the NCIB will be cancelled.

As detailed in the Highlights and Outlook section, the Company has declared the distribution of the Company's third quarterly cash dividend in 2025 of approximately $25.0 million or $0.0371 per share.

GROUP OPERATIONS

On March 19, 2025, the Company completed the transaction with BTG Oil & Gas to consolidate its interest in Meren Coöperatief U.A (Previously known as Prime Oil & Gas Coöperatief U.A) ("Meren Coop"). The acquisition was completed by way of amalgamation whereby BTG Oil & Gas exchanged its 50 percent interest in Meren Coop, 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 Meren Coop production numbers for all periods to have comparable production numbers for the purpose of this MD&A.

Production and Operations

Production Metrics – rounded

		Three months ended		Six months ended		Year ended
	Unit	June 30, 2025	June 30, 2024	June 30, 2025	June 30, 2024	December 31, 2024
Total gross field production	boepd	248,100	258,100	255,400	271,300	273,600
Average daily WI production (1)	boepd	30,900	31,600	32,100	33,400	34,000
Average daily entitlement production	boepd	35,700	36,600	36,700	38,600	38,800
Oil volumes sold	MMbbl	1.0	3.0	6.0	5.0	9.0
Gas volumes sold	bcf	5.0	3.6	10.0	7.8	17.4
Oil/gas percentage split (2)	%	72%/28%	83%/17%	72%/28%	83%/17%	77%/23%

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

(2) Calculated on a working interest basis.

The total gross field production in Q2 2025 decreased compared to Q2 2024, primarily from the events outlined below and natural reservoir decline across all assets. Production was actively managed during operational challenges, ensuring steady performance across fields.

Production from Akpo and Egina was temporarily adjusted in response to gas export restrictions linked to high liquid levels at the NLNG transmission system. Proactive maintenance measures were also taken on the Amenam gas export bypass line early in the quarter, reinforcing the integrity of the asset. In Agbami, production was adjusted due to flare management, and maintenance on the seawater injection system, ensuring continued operational safety.

These changes to production were partially offset by strong contributions from the two new Egina wells bought on stream in May, which are performing in line with expectations and strong well performance in Akpo, supporting Q2 targets. Production from these wells will continue to be optimised throughout Q3 2025. A successful well intervention was finalized in July and is restoring production levels from the G reservoir and will further strengthen Q3 performance. There will be no further drilling during 2025.

In Q2 2025, one oil lifting was allocated with a total sales volume of approximately 1.0 million barrels of oil at a realized oil price of $64.2/bbl. In Q2 2024, three oil liftings were allocated with total sales volume of approximately 3.0 million barrels at an average realized oil price of $89.0/bbl.

In H1 2025, 6 oil liftings were allocated with a total sales volume of approximately 6.0 million barrels at an average realised oil price of $77.0/bbl, compared to Dated Brent average of $71.8/bbl. In H1 2024 5 oil liftings were allocated with a total sales volume of approximately 5.0 million barrels at an average realised oil price of $87.6/bbl.

In 2024, nine oil liftings were allocated 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 Meren Coop 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 Meren 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 a constructed financial information basis.

Constructed financial information to explain performance is included in the following tables to present on a consolidated basis net income for H1 2025 and cash flow statement for H1 2025, whereby the Meren interim condensed consolidated statement of net income and comprehensive income and the Meren interim condensed consolidated statement of cash flows for H1 2025 are combined with the Meren Coop statement of net income and comprehensive income and the Meren Coop statement of cash flows for the period until March 19, 2025. The reported numbers for Meren Coop for the period up to and including March 19, 2025, includes some updates to the Meren Coop statement of net income and comprehensive income and to the Meren Coop statement of cash flows compared to the interim condensed consolidated financial statements for the period ended March 31, 2025. Adjustments in the constructed financial information are included to conform Meren Coop financial information with Meren accounting policies and for any transactions between Meren and Meren Coop prior to amalgamation for the purpose of presenting constructed financial information to explain performance.

Constructed financial information for purposes of explaining performance

Interim condensed consolidated statement of net income

(Expressed in millions of United States Dollars)

For the six months ended	Meren H1 2025 per Financial Statements	Meren Coop for period from January 1, 2025, to March 19, 2025	Adjustments (1)	June 30, 2025
Revenue	145.7	323.5	-	469.2
Cost of Sales				
Production costs	(5.2)	(187.4)	2.0	(190.6)
Depletion costs	(82.0)	(71.3)	-	(153.3)
	(87.2)	(258.7)	2.0	(343.9)
Gross profit	58.5	64.8	2.0	125.3
General and administrative expenses	(22.2)	(6.2)	-	(28.4)
Operating (loss)/ profit	36.3	58.6	2.0	96.9
Finance income	2.4	2.4	-	4.8
Finance expense	(20.3)	(21.3)	-	(41.6)
Net financial items	(17.9)	(18.9)	-	(36.8)
Share of profit from investment in joint venture	2.9	-	(2.9)	-
Share of loss from investments in associates	(2.0)	-	-	(2.0)
Reversal of impairment of investment in joint venture	55.9	-	(55.9)	-
Profit before tax	75,2	39.7	(56.8)	58.1
Income tax	(21.2)	(34.0)	-	(55.2)
Net income attributable to common shareholders	54.0	5.7	(56.8)	2.9

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

BUSINESS UPDATE - CONTINUED

Interim condensed consolidated statement of cash flows
(Expressed in millions of United States Dollars)

For the six months ended	Meren H1 2025 per Financial Statements	Meren Coop for period from January 1, 2025, to March 19, 2025	Adjustments [1]	June 30, 2025
Cash flows generated by/ (used in):				
Operations				
Profit before tax	75.2	39.7	(56.8)	58.1
Adjustments as per financial statements	19.1	41.5	58.8	119.4
Net cash generated in operating activities before working capital	94.3	81.2	2.0	177.5
Changes in working capital	(47.5)	(8.2)	-	(55.7)
Net cash generated in operating activities	46.8	73.0	2.0	121.8
Investing				
Investments in oil and gas properties and intangible exploration assets	(34.0)	(22.6)	(2.0)	(58.6)
Investments in other fixed assets	(0.4)	-	-	(0.4)
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	2.5	2.2	-	4.7
Cash acquired from Meren Coop consolidation [2]	380.4	-	(381.3)	(0.9)
Net cash generated/ (used) in investing activities	444.6	(20.4)	(443.3)	(19.1)
Financing				
Repayment RBL Facility	(210.0)	-	-	(210.0)
Repayment of principal portion of lease commitments	(0.3)	-	-	(0.3)
Dividends paid to shareholders	(50.1)	(120.0)	120.0	(50.1)
Repurchase of share capital	(8.3)	-	-	(8.3)
Interest expense paid	(17.5)	(10.8)	-	(28.3)
Net cash (used)/ generated in financing activities	(286.2)	(130.8)	120.0	(297.0)
Foreign exchange variation on cash and cash equivalents	-	-	-	-
Total cash flow	205.2	(78.2)	(321.3)	(194.3)
Cash and cash equivalents, beginning of the period	61.4	399.5	-	460.9
Cash and cash equivalents, end of the period	266.6	321.3	(321.3)	266.6

(1) Adjustments to remove items related to Meren Coop as Meren Coop 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 June 30, 2025	Three months ended June 30, 2024	Six months ended June 30, 2025	Six months ended June 30, 2024	Year ended December 31, 2024
Total revenues	$'m	69.3	268.7	469.2	445.3	782.7
Cost of Sales [2]	$'m	23.9	176.5	343.9	257.2	428.2
Gross profit	$'m	45.4	92.2	125.3	188.1	354.5
Opex/boe [3,4]	$/boe	11.5	10.5	12.5	10.4	10.3
Cash flow from operations before working capital	$'m	77.7	n/a	177.5	n/a	n/a
Cash flow from operations	$'m	10.4	n/a	121.8	n/a	n/a
Free cash flow	$'m	(18.9)	n/a	102.7	n/a	n/a
Free cash flow/boe [4]	$/boe	(5.9)	n/a	15.6	n/a	n/a
Tax	$'m	43.5	31.9	55.2	53.1	120.5
Capex	$'m	30.4	n/a	58.6	n/a	n/a
Net Debt	$'m	273.4	258.9	273.4	258.9	289.1
EBITDAX	$'m	106.6	n/a	248.2	n/a	n/a
Net Debt/EBITDAX [5]	ratio	0.6	n/a	0.6	n/a	n/a

(1) The table includes non-GAAP measures. Definitions and reconciliations to these non-GAAP measures are provided on pages 13-16.

(2) Given the nature of the Company'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 H1 2025 EBITDAX multiplied by 2.

Total revenues

	Unit	Three months ended June 30, 2025	Three months ended June 30, 2024	Six months ended June 30, 2025	Six months ended June 30, 2024	Year ended December 31, 2024
Oil revenue	$'m	64.4	264.0	458.9	435.0	762.2
Gas revenue	$'m	4.9	4.7	10.3	10.3	20.5
Total revenue	**$'m**	**69.3**	**268.7**	**469.2**	**445.3**	**782.7**
Realized oil prices [1]	$/bbl	64.2	89.0	77.0	87.6	84.6
Oil volumes sold	MMbbl	1.0	3.0	6.0	5.0	9.0
Realized gas prices	$'m/bcf	1.0	1.3	1.0	1.3	1.2
Gas volumes sold	Bcf	5.0	3.6	10.0	7.8	17.4

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

BUSINESS UPDATE - CONTINUED

The decrease in oil revenue in Q2 2025 was mainly driven by lower liftings compared to Q2 2024 and a lower realized price of $64.2/bbl in Q2 2025 compared to $89.0/bbl in Q2 2024.

The increase in oil revenue in H1 2025 was mainly driven by higher liftings compared to H1 2024 despite a lower realized oil price of $77.0/bbl in H1 2025 compared to $87.6/bbl in H1 2024.

Cost of sales

	Three months ended		Six months ended		Year ended
$'m	June 30, 2025	June 30, 2024	June 30, 2025	June 30, 2024	December 31, 2024
Depletion costs	69.9	94.3	153.3	191.0	372.0
Cost of operations	36.9	35.7	82.5	73.0	146.1
Movements on overlift/ underlift balances	(96.3)	23.8	78.7	(52.4)	(171.2)
Royalties – oil and gas	10.0	19.2	23.2	38.2	70.2
Others	3.4	3.5	6.2	7.4	11.1
Total cost of sales	**23.9**	**176.5**	**343.9**	**257.2**	**428.2**

Cost of sales decreased in Q2 2025 compared to Q2 2024. The decrease in costs of sales is mainly driven by a large underlift movement in Q2 2025 compared to an overlift movement in Q2 2024, lower depletion costs and lower royalties as a result of lower oil prices.

Cost of sales increased in H1 2025 compared to H1 2024. The increase in costs of sales is mainly driven by a large overlift movement in H1 2025 compared to an underlift movement in Q1 2024, this was offset against lower depletion costs and lower royalties as a result of lower oil prices.

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		Six months ended		Year ended
	Unit	June 30, 2025	June 30, 2024	June 30, 2025	June 30, 2024	December 31, 2024
Cost of operations	$'m	36.9	35.7	82.5	73.0	146.1
Entitlement production	MMboe	3.2	3.4	6.6	7.0	14.2
Opex/boe	**$/boe**	**11.5**	**10.5**	**12.5**	**10.4**	**10.3**

Opex/boe increased in Q2 2025 and H1 2025 compared to Q2 2024 and H1 2024 primarily from lower entitlement production.

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

BUSINESS UPDATE - CONTINUED

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		Six months ended		Year ended
$'m	June 30, 2025 (1)	June 30, 2024 (1)	June 30, 2025 (1)	June 30, 2024 (1)	December 31, 2024 (1)
Cash flow from operations	10.4	n/a	121.8	n/a	n/a
Working capital adjustments included in cash flow from operations	67.3	n/a	55.7	n/a	n/a
Cash flow from operations before working capital	**77.7**	**n/a**	**177.5**	**n/a**	**n/a**

(1) Cash flow from operations has been reported for the year 2025 only, on a constructed financial information basis.

Free cash flow and Free cash flow/boe

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		Six months ended		Year ended
	Unit	June 30, 2025 (1)	June 30, 2024 (1)	June 30, 2025 (1)	June 30, 2024 (1)	December 31, 2024 (1)
Total cash flow	$'m	(161.8)	n/a	(194.3)	n/a	n/a
Add back dividends paid to shareholders	$'m	50.1	n/a	50.1	n/a	n/a
Add back repurchase of share capital	$'m	-	n/a	8.3	n/a	n/a
Add back debt service costs (2)	$'m	92.8	n/a	238.6	n/a	n/a
Free cash flow	**$'m**	**(18.9)**	**n/a**	**102.7**	**n/a**	**n/a**
Entitlement production	MMboe	3.2	n/a	6.6	n/a	n/a
Free cash flow/boe	**$/boe**	**(5.9)**	**n/a**	**15.6**	**n/a**	**n/a**

(1) Free cash flow and Free cash flow/boe have been reported for the year 2025 only, on a constructed financial information basis.

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

BUSINESS UPDATE - CONTINUED

Tax

The tax expense is made up of the following items:

	Three months ended		Six months ended		Year ended
$'m	June 30, 2025	June 30, 2024	June 30, 2025	June 30, 2024	December 31, 2024
Deferred income tax	17.4	(13.4)	(16.9)	(29.4)	(80.9)
Education tax	4.3	3.5	5.8	7.0	14.2
Corporate income tax	21.8	36.6	48.3	67.9	130.1
Withholding tax on dividends	-	7.5	18.0	7.5	22.5
Capital gains tax	-	-	-	-	33.0
Petroleum Profit Tax	-	(2.3)	-	(2.3)	(2.3)
Other taxes	-	-	-	2.4	3.9
Total tax	**43.5**	**31.9**	**55.2**	**53.1**	**120.5**

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

Corporate income tax is imposed at a rate of 30.0% of the assessable profits in Nigeria 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 PIA 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.

Capital expenditure

Capital expenditure is made up of the following items:

	Three months ended		Six months ended		Year ended
$'m	June 30, 2025 (1)	June 30, 2024 (1)	June 30, 2025 (1)	June 30, 2024 (1)	December 31, 2024 (1)
Nigeria	29.5	n/a	55.9	n/a	n/a
Equatorial Guinea	0.9	n/a	2.6	n/a	n/a
South Africa	-	n/a	0.1	n/a	n/a
Total capex	**30.4**	**n/a**	**58.6**	**n/a**	**n/a**

(1) Capital expenditure has been reported for the year 2025 only, on a constructed financial information basis.

Capital expenditure in Q2 and H1 2025 in Nigeria mainly related to infill drilling on Egina and Akpo 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.

	Six months ended		Year ended
As at/ $'m	June 30, 2025	June 30, 2024	December 31, 2024
Loans and borrowings	540.0	750.0	750.0
Cash and cash equivalents	(266.6)	(491.1)	(460.9)
Net Debt	**273.4**	**258.9**	**289.1**

As at June 30, 2025, the Company has $266.6 million of cash and cash equivalents and $540.0 million of debt (as at December 31, 2024 - $460.9 million of cash and cash equivalents and $750.0 million of debt). During H1 2025, the Company pro-actively repaid $210.0 million under its RBL facility reducing outstanding debt to $540.0 million. RBL facility headroom of $94.1 million at the end of Q2 2025.

BUSINESS UPDATE - CONTINUED

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		Six months ended		Twelve months ended	
$'m	June 30, 2025 (1)	June 30, 2024 (1)	June 30, 2025 (1)	June 30, 2024 (1)	June 30, 2025 (1)	December 31, 2024 (1)
Total profit/ (loss)	(23.0)	n/a	2.9	n/a	n/a	n/a
Add back:						
Tax	43.5	n/a	55.2	n/a	n/a	n/a
Finance costs	17.5	n/a	41.6	n/a	n/a	n/a
Finance income	(1.3)	n/a	(4.8)	n/a	n/a	n/a
Depletion and decommissioning costs	69.9	n/a	153.3	n/a	n/a	n/a
EBITDAX	**106.6**	**n/a**	**248.2**	**n/a**	**n/a**	**n/a**
Net Debt	273.4		273.4			
Net Debt/EBITDAX (2)	**0.6**		**0.6**			

(1) EBITDAX and Net Debt/EBITDAX have been reported for the year 2025 only, on a constructed financial information basis.

(2) Net debt/EBITDAX has been calculated based on extrapolating H1 2025 EBITDAX to a full year EBITDAX number.

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 average cargo size lifted is one million barrels of oil.

Oil sales were comprised of the following:

		Three months ended		Six months ended		Year ended
Oil Sales	Unit	June 30, 2025	June 30, 2024	June 30, 2025	June 30, 2024	December 31, 2024
Number of cargo liftings		1	3	6	5	9
Of which:						
Sold forward with a fixed Dated Brent		1	-	3	-	2
Sold at spot		-	3	3	5	7
		1	**3**	**6**	**5**	**9**
Gross crude oil sales						
Quantity in Mboe	Mboe	1,002.7	2,964.6	5,962.8	4,965.2	9,012.8
Average sales price	$/bbl	64.2	89.0	77.0	87.6	84.6
Average Bloomberg Dated Brent for the period	$/bbl	67.9	84.9	71.8	84.0	82.7

BUSINESS UPDATE - CONTINUED

The Company sold 1 cargo during Q2 2025 at a price of $64.2/bbl. Of the 6 cargoes expected for the remainder of the year post Q2 2025, 3 cargos have the trigger price mechanism activated at an average price of $64.6/bbl. The remaining 3 cargoes are currently unhedged with no trigger price mechanism in place.

The combination of achieved sales prices in H1 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 Q3-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.

Please refer to pages 19 - 20 of the Company's Annual Information Form ("AIF") 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 on these assets. The AIF is available on available on SEDAR+ at www.sedarplus.ca or on the Company's website at www.mereninc.com.

During Q2 2025, activities across the Nigerian asset base continued to focus on optimising production performance across the three producing fields, while also progressing efforts to mature the remaining non-producing assets towards an investment decision.

At Egina, two new producer wells drilled during Q1 2025 were successfully brought on stream in Q2 2025, contributing towards field performance. There is no further Egina drilling activity planned for the remainder of this year.

During Q2 2025, drilling activity on the planned Akpo infill wells was paused to allow for the analysis and optimization of the drilling campaign. This measured step ensures future operations are informed by enhanced planning and learnings, as well as benefitting from the seismic results. The next campaign is targeted for 2026. This break will provide an opportunity to mature well candidates for the next campaign and efforts are currently underway to secure a rig for 2026.

Block 3B/4B – South Africa

Meren, through a wholly-owned subsidiary, holds an 18.0% interest in Block 3B/4B, which lies in the Orange Basin. During Q2 2025, the Company and its JV partners progressed the technical work ahead of the first exploration campaign on this block, which is expected during 2026 subject to satisfactory completion of regulatory and legal processes.

Please refer to the Company's AIF for the year-ended December 31, 2024, for further details on Block 3B/4B.

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.

During Q2 2025 the Company progressed the technical work in support of its farm down activities to attract industry partners to share exploration costs and risks. The data room for both blocks opened during Q2 2025 and dialogue with interested parties is ongoing.

Please refer to the Company's AIF for the year-ended December 31, 2024, for further details on Blocks EG-18 and EG-31.

EQUITY INVESTMENTS IN ASSOCIATES

As at June 30, 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 June 30, 2025:

	Africa Energy	Impact [1]
Issued and Outstanding	479,162,450	1,139,147,442
Shares held by Meren at December 31, 2024	55,396,483	449,464,396
Shares acquired in the period	-	-
Shares held by Meren at June 30, 2025	55,396,483	449,464,396
Meren's holding (%) – June 30, 2025	11.56%	39.46%
Meren's holding (%) – December 31 2024	19.67%	39.46%
Share price (CAD) on June 30, 2025	0.15	-
Exchange rate to USD on June 30, 2025	0.73	-

(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. Please refer to the Company's AIF for the year-ended December 31, 2024, for further details on the Company's shareholding in Impact and the supplementary technical and commercial information.

During Q2 2025, the JV partners progressed the technical work and development planning for the Venus project with the final investment decision expected during H1 2026.

During Q2 2025, Marula-1X exploration well on Block 2913B 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.

ENVIRONMENTAL, SOCIAL AND GOVERNANCE

Following the amalgamation, the Company reiterates its commitment to operating in a responsible manner that integrates sustainability considerations throughout its decision-making and operational management, to support Company commercial objectives.

Work is ongoing to integrate the health, safety, environment and communities (HSEC) policies and procedures of the two former businesses. Previous work undertaken to align the former Meren Coop policies and procedures with those of the former Africa Oil means that this is more an administrative reorganization than a material change in governance systems.

During H1 2025 there were no reported material HSEC incidents (in terms of fatalities or uncontrolled releases to the environment).

GHG emissions during the reporting period were in line with operational forecasts. Further details will be set out in the Company's annual Sustainability Report.

An independent HSEC monitoring review of Nigeria assets (to support an existing reserves-based lending facility established by Meren Coop) found that "as a non-operating partner with limited operational control over the JV assets, Meren Coop exercised commendable diligence in overseeing ESHS matters."

Activities continue on the Company's development assets with no material developments to be reported during the reporting period.

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

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	30-Jun 2025	31-Mar 2025	31-Dec 2024	30-Sep 2024	30-Jun 2024	31-Mar 2024	31-Dec 2023	30-Sep 2023
Revenue	69.3	76.4	-	-	-	-	-	-
Net income/ (loss) attributable to common shareholders ($'m)	3.1	50.9	6.2	(289.2)	0.4	3.5	(88.8)	47.1
Weighted average shares – Basic '000	675,012	468,472	442,690	442,960	451,231	460,991	462,231	462,340
Weighted average shares – Diluted '000	682,039	476,836	449,667	442,960	464,890	474,746	472,942	473,959
Basic income / (loss) per share ($)	0.00	0.11	0.02	(0.65)	0.00	0.01	(0.19)	0.10
Diluted income/ (loss) per share ($)	0.00	0.11	0.02	(0.65)	0.00	0.01	(0.19)	0.10

SUMMARY OF KEY ITEMS OF FINANCIAL PERFORMANCE IN THE THREE AND SIX MONTHS ENDED JUNE 30, 2025, AND JUNE 30, 2024

	Three months ended		Six months ended	
	June 30, 2025	June 30, 2024	June 30, 2025	June 30, 2024
Revenue	69.3	-	145.7	-
Gross Profit	45.4	-	58.5	-
General and administrative expenses	(8.7)	(10.4)	(22.2)	(15.5)
Net income/ (loss)	3.1	(0.7)	54.0	1.4

Revenue

Revenue generated in Q2 2025 and H1 2025 was $69.3 million and $145.7 million respectively (Q2 2024 and H1 2024 – nil) and relates to 1 cargo sold in Q1 2025 post amalgamation at a price of $74.2/bbl and another cargo in Q2 2025 at a price of $64.2/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 Q2 2025 and H1 2025 was $45.4 million and $58.5 million respectively (Q2 2024 and H1 2024 – nil). Gross profit was impacted by costs of sales in Q2 2025 and H1 2025 of $23.9 million and $87.2 million respectively (Q1 2024 – nil) and mainly comprised of depletion costs of $69.9 million and $82.0 million respectively, net underlift movements on overlift/underlift balances of $96.3 million and $54.4 million respectively and costs of operations of $36.9 million and $44.3 million respectively.

SUMMARY OF QUARTERLY INFORMATION - CONTINUED

General and administrative costs

On March 19, 2025, the Company announced the completion of the amalgamation to acquire the remaining 50% interest in Meren Coop in exchange for 239,828,655 newly issued common shares in Meren. 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		Six months ended	
	June 30, 2025	June 30, 2024	June 30, 2025	June 30, 2024
General and administrative expenses	8.7	10.4	22.2	15.5
BTG Oil & Gas transaction related expenses	(1.4)	(5.1)	(9.0)	(5.4)
Adjusted general and administrative expenses	**7.3**	**5.3**	**13.2**	**10.1**

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, in Q2 2025 and H1 2025 amounted to $7.3 million and $13.2 million respectively (Q2 2024 and H1 2024 - $5.3 million and $10.1 million respectively). Share-based compensation charges not impacted by the closing of the amalgamation in Q2 2025 and H1 2025 amounted to a credit of $0.2 million and a charge of $1.0 million respectively (Q2 2024 and H1 2025 – $1.3 million and $1.8 million respectively) are impacted by movements in the share price of the Company.

Adjusted general and administrative expenses excluding share-based compensation charges amounted to $7.5 million in Q2 2025 compared to $4.0 million in Q2 2024. The increase of $3.5 million is primarily driven by higher costs following the amalgamation and higher headcount.

Adjusted general and administrative expenses excluding share-based compensation charges amounted to $12.2 million in H1 2025 compared to $8.3 million in H1 2024. The increase of $3.9 million is also primarily driven by higher costs following the amalgamation and higher headcount.

SUMMARY OF KEY ITEMS OF FINANCIAL POSITION AS AT JUNE 30, 2025, AND DECEMBER 31, 2024

As at	June 30, 2025	December 31, 2024
Assets		
Oil and gas properties	1,610.3	-
Intangible exploration assets	39.9	29.3
Equity investments in associates	143.1	177.6
Trade receivables	69.0	-
Cash and cash equivalents	266.6	61.4
Outstanding bank debt	(540.0)	-

Oil and gas properties

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

As at June 30, 2025, oil and gas properties amounted to $1,610.3 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 June 30, 2025, the carrying amount of the Company's intangible exploration assets in Equatorial Guinea was $20.5 million (as at December 31, 2024 – $17.9 million) and related to its 80% interest in Blocks EG-18 and EG-31.

As at June 30, 2025, the carrying amount of the Company's intangible exploration assets in South Africa was $19.4 million (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 June 30, 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 H1 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 Meren Coop following which Meren Coop is fully consolidated by the Company. Trade receivables relates to one cargo sale during June.

Cash and cash equivalents

Cash and cash equivalents have increased following closing of the amalgamation to acquire the remaining 50% interest in Meren Coop following which Meren Coop is fully consolidated by the Company. As at June 30, 2025, the Company had $266.6 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 Meren Coop of $60.0 million prior to the closing of the amalgamation, repaid $210.0 million of the RBL facility, returned $58.4 million to shareholders by way of dividends and 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 Meren Coop following which Meren Coop is fully consolidated by the Company. Subsequent to closing of the amalgamation, the Company pro-actively repaid $210.0 million under the RBL facility, reducing outstanding bank debt to $540.0 million as at June 30, 2025. RBL facility headroom of $94.1 million at the end of Q2 2025.

LIQUIDITY AND CAPITAL RESOURCES

As at June 30, 2025, the Company had cash balances of $266.6 million and working capital balances (including cash balances) of $120.2 million, calculated as current assets less current liabilities as presented in the interim condensed consolidated balance sheet as per June 30, 2025. The Company's primary source of liquidity is operating income in Nigeria and the remaining undrawn amounts on the RBL.

Reserves Based Lending Facility

Meren has a Reserves Based Lending Facility ("RBL") in place. 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 June 30, 2025, the BBA was $634.0 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 Meren Coop level – Meren Coop is the borrower, and Meren 52 and Meren 234 are the guarantors. The main security package is comprised of security over the shares, production assets, contracts and rights of the Nigerian entities - Meren 52 and Meren 234. 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 entities.

All financial and liquidity covenants covered by the RBL are restricted to these three entities. The 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 June 30, 2025.

Corporate Facility

On May 22, 2025, the Company cancelled its $65.0 million Corporate Facility.

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	675,512,565
Outstanding share purchase options	457,616
Outstanding restricted share units	717,698
Outstanding performance share units	6,597,299
Full dilution impact on Common Shares outstanding	683,285,178

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 during 2025, and $0.2 million and $0.5 million was provided in the three and six months ended June 30, 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 and six months ended June 30, 2024 - $0.1 million and $0.1 million respectively).

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. Meren 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 14 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.

MEREN COÖPERATIEF U.A:

Under the Meren Coop 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 Meren Coop 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 Meren Coop 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 $41.7 million in the six months ended June 30, 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 June 30, 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 June 30, 2025.

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 Meren 52 and Meren 234, cash and cash equivalents in the amount of $208.0 million as per June 30, 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 June 30, 2025, three 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 three cargos covered by forward contracts have been triggered in April 2025 at an average of $64.6 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 Meren Coop.

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 and six months ended June 30, 2025

CRITICAL ACCOUNTING ESTIMATES - CONTINUED

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.

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 Meren Coop. 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.

CRITICAL ACCOUNTING ESTIMATES - CONTINUED

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.

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.

CRITICAL ACCOUNTING ESTIMATES - CONTINUED

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 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 Meren Coop. Results for Meren Coop, 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 June 30, 2025, include current assets of $515.0 million, non-current assets of $1,610.9 million, current liabilities of $366.6 million, non-current liabilities of $1,005.6 million as of June 30, 2025, and revenues of $145.7 million and profit before tax of $39.0 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 Meren Coop'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 June 30, 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 June 30, 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.

Risks that can materially affect the figures presented and disclosed in the Financial Statement and MD&A are described in the Company's Annual Information Form for the year ended December 31, 2024 ("AIF") available on SEDAR+ at www.sedarplus.ca or on Meren's website at www.mereninc.com/investor-summary/financial-reports-meetings-filings/.

The following additional risks that can materially affect the figures presented and disclosed in the Financial Statement and MD&A have been identified following completion of the transaction with BTG Oil & Gas to consolidate the interest in Meren Coop.

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.

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.

Meren

mereninc.com