Meren

Meren Energy Inc.

Report to Shareholders

For the Period Ended September 30, 2026

Q3 26

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"	means the Amalgamation transaction 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.
	"Applicable law"	means all laws and regulations issued by authorities that have appropriate jurisdiction over the Company.
	"Azinam"	means Azinam Limited, a wholly owned subsidiary of Eco.
B	"Bcf"	means billion cubic feet.
	"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"	means concessions, PSAs, PSCs 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.
D	"DD&A"	means Depreciation, Depletion and Amortization.
E	"EBITDAX"	means Earnings Before Interest, Taxes, Depreciation & Impairment, Amortization and Exploration Expenses.
	"Eco"	means Eco (Atlantic) Oil & Gas Ltd.
	"Entitlement production"	means production that is calculated using the economic interest methodology and includes cost oil, profit oil and royalty oil.
	"ESIA"	means Environmental and Social Impact Assessment.
F	"FDP"	means Field Development Plan.
	"FEED"	means Front End Engineering and Design.
	"FID"	means Final Investment Decision.
	"FPSO"	means Floating Production Storage and Offloading.
G	"GHG"	means Greenhouse Gas.
	"GTCs"	means Gas Turbine Compressors.
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	"LTIP"	means Long Term Incentive Plan.

M	"Mcf"	means thousand 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 52"	means Meren Nigeria 52 Limited (previously named Prime 127 Nigeria Limited).
	"Meren 234"	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	"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 2003"	means the Petroleum Prospecting License containing the Ikija field.
	"PPL 261"	means the Petroleum Prospecting License containing the Egina South discovery.
	"PPT"	means Petroleum Profits Tax.
	"PRMS"	means Petroleum Resources Management System.
	"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	"SOFR"	means Secured Overnight Financing Rate.
	"spud" or "spudded"	means the initial drilling for an oil well.
T	"TAM"	means planned turnaround maintenance.
	"TotalEnergies"	means TotalEnergies SE and subsidiaries.
	"TSX"	means Toronto Stock Exchange.
U	"UPU"	means Upstream Petroleum Unit.
	"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 nine months ended September 30, 2026, 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 nine months ended September 30, 2026, and 2025, and also should be read in conjunction with the audited consolidated financial statements for the years ended December 31, 2025, and 2024, and related notes thereto.

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

This MD&A was reviewed and approved by the Board of Directors. The effective date of this MD&A is November 10, 2026.

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.ca.

PROFILE AND STRATEGY

Meren is a Canadian full-cycle independent upstream oil and gas company with interests offshore Nigeria, Namibia, South Africa and Equatorial Guinea.

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'.

The Company's common shares also trade on the OTCQX Best Market ("OTCQX") in the U.S. under the ticker 'MRNFF'.

Meren's strategy is anchored in maintaining a resilient balance sheet through the cycle, prioritizing high-return organic investment in its core assets, and delivering sustainable shareholder returns from surplus free cash flow. 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 and appraisal 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 further prospectivity.

HIGHLIGHTS AND OUTLOOK

Q3 2026, NINE MONTHS 2026 AND POST PERIOD HIGHLIGHTS

FINANCIAL

- Recorded EBITDAX of $112.8 million in Q3 2026 and $332.3 million in the first nine months, with cash flow from operations before working capital of $73.6 million and $213.0 million respectively, demonstrating continued cash generation and supporting a revised full-year guidance for each, which is substantially above the Company's original guidance.
- Net debt reduced by $27.1 million in Q3 to $185.2 million, with free cash flow of $59.1 million. Net Debt/EBITDAX of 0.5x, comfortably below the Company's internal 1.0x through-the-cycle leverage target, further enhancing balance sheet strength ahead of near-term capital investment.
- Total liquidity of $327.9 million at period-end, comprising cash and available RBL headroom following the March 2026 RBL refinancing, which upsized the facility to $600 million (with an accordion to $1 billion) and extended final maturity to March 2032.
- Declared the fourth 2026 quarterly dividend of $25.1 million ($0.0371/share), bringing 2026 declared distributions to $100.3 million.
- Recorded a loss on commodity risk management contracts of $35.3 million in Q3 2026, of which $13.1 million was realized, with the balance a non-cash mark-to-market revaluation.
- Recorded capital investments of $38.0 million in the first nine months of 2026, mostly in Nigeria. Full-year capital investments are now expected to be within the updated guidance range of $70.0 - $90.0 million, reflecting the expected timing of the drilling campaigns.

OPERATIONAL

- In the first nine months of 2026, average daily WI production of 26,900 boepd and entitlement production of 29,800 boepd, on track to be within the updated guidance ranges of 25,000 – 27,000 boepd and 29,000 – 31,000 boepd respectively, with WI production towards the upper end of original guidance and Akpo and Egina both producing above plan by September.
- In the first nine months of 2026, unit operating costs of $15.8/boe on an entitlement basis, supporting continued cash generation.
- Nigeria drilling preparations progressed, with the rig now on location for the Akpo and Egina drilling campaign, set to begin in November. A vessel-led campaign of subsea well interventions at both fields remains on track in Q4 to add short-term, low cost, incremental production that complements the drilling activity.
- Post-period, the South African Minister of Forestry, Fisheries and Environment dismissed appeals against the Block 3B/4B Environmental Authorization on October 13, 2026, advancing the project towards the first exploration well on the Nayla prospect, subject to any judicial review proceedings.

COMMERCIAL

- In Q3 2026, sold two cargoes (approximately 2 MMbbl) at an average all-in realized sales price of $92.4/bbl, compared with an average Bloomberg Dated Brent price of $86.9/bbl during July and August, when the cargoes were lifted.

HIGHLIGHTS AND OUTLOOK - CONTINUED

FINANCIAL SUMMARY

The comparative period numbers as included in this financial summary are no longer presented on a constructed financial information basis. The comparative period numbers are derived from the interim condensed consolidated financial statements for the three and nine months ended September 30, 2025, and from the consolidated financial statements for the year ended December 31, 2025. Comparative period numbers will therefore be different compared to those presented in the Management's Discussion and Analysis for the nine months ended September 30, 2025, and for the year ended December 31, 2025.

		Three months ended		Nine months ended		Year ended
	Unit	September 30, 2026	September 30, 2025	September 30, 2026	September 30, 2025	December 31, 2025
Meren Highlights						
Net income/ (loss)	$'m	1.3	5.2	(9.1)	59.2	(31.6)
Net income/ (loss) per share - basic [1]	*$/ share*	*0.00*	*0.01*	*(0.01)*	*0.10*	*(0.05)*
Net debt position [2]	$'m	185.2	183.3	185.2	183.3	155.3
WI production	boepd	25,300	31,100	26,900	31,300	30,200
Entitlement production	boepd	28,300	35,600	29,800	35,900	34,500
Cash flow from operations [2][3]	$'m	73.6	65.6	213.0	159.9	272.6
EBITDAX (2)	$'m	112.8	119.8	332.3	238.5	311.6
Capital investments	$'m	14.4	21.8	38.0	55.8	75.6

(1) Based on the weighted average number of shares outstanding for the respective period.

(2) The table includes non-GAAP measures. Definitions and reconciliations to these non-GAAP measures are provided on pages 13 - 16. EBITDAX no longer includes Meren's share of result from investments in associates and joint venture and related impairment reversals.

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

HIGHLIGHTS AND OUTLOOK - CONTINUED

OUTLOOK

Nigeria

Meren expects to enter a sustained period of investment across its Nigerian deepwater portfolio, starting in late 2026 and running into the early 2030s. The programme is designed to add reserves and production from existing hubs, offset natural decline and progress the Company's discovered resources towards development. It is supported by long-dated licenses (PMLs 2, 3 and 4 to 2043; PML 52 to 2044) and an improving deepwater investment framework in Nigeria.

In PMLs 2 and 3, the drilling rig has arrived at Akpo for a multi-well programme across Akpo and Egina. The operator is preparing to commence drilling in November 2026, starting with the Akpo Far East exploration well (AFE-1X). In the success case, a low-cost tie-back to the Akpo infrastructure is planned. It would add reserves and production and support the case for extending Akpo's life. Subsurface work and maturation of further infill opportunities continue across both fields. Well interventions on Akpo and Egina remain on track for completion in 2026, supporting production ahead of the drilling campaign.

For Agbami ("PML 52") and Ikija ("PPL 2003"), preparations for the upcoming drilling programme continued during the quarter, with the drilling rig now expected to arrive in Q1 2027. Following optimisation, the programme is currently expected to comprise a three-well Agbami infill campaign, which is designed to deliver a high level of oil recovery at a lower capital cost, together with the Ikija appraisal well, with the sequencing currently being finalised. A successful Ikija well would underpin the field development plan, with development through a tie-back to the Agbami FPSO.

For PML 4 (Preowei), the operator continues to optimise the development concept and costs and has started preliminary engagement with potential contractors. Meren and its partners continue to move towards a final investment decision, subject to completion of FEED and the requisite partner and regulatory approvals. The operator has publicly identified Preowei among the projects it plans to sanction in the next few years. The Deep Offshore Oil and Gas Projects Incentives Order, signed in August 2026, provides production tax credits for qualifying projects that reach FID by the end of 2029. Preowei is the type of greenfield development the Order is designed to support. It is expected to be a subsea tie-back to the Egina FPSO.

In PPL 261 (Egina South), the operator of the adjacent OPL 257 plans appraisal drilling in 2027. The results will help define the resource range across both licenses and the optimal potential development plan for tieback to the Egina FPSO.

The operators of Agbami and Akpo are progressing asset integrity and life-extension programmes for the FPSOs which are expected to support the continued development of future drilling and tie-back opportunities. They are expected to become a more significant part of the Company's investment over the coming years.

The Company expects to fund this programme from operating cash flow and available liquidity, while keeping a robust balance sheet. This growth phase is the context in which capital allocation decisions, including shareholder distributions, will be made.

NAMIBIA ORANGE BASIN DEVELOPMENT AND EXPLORATION, BLOCKS 2912 AND 2913B

TotalEnergies, the operator, continues to advance the Venus development in Block 2913B (PEL 56), offshore Namibia, in which the Company holds an effective interest of approximately 3.8% through its shareholding in Impact Oil & Gas Limited ("Impact"). Venus remains the most advanced deepwater project in the Orange Basin: front-end engineering and design (FEED) has been completed, the main contractors have been selected and the operator has stated that the project is moving towards sanction.

In July 2026, Namibia's Ministry of Industries, Mines and Energy approved TotalEnergies' asset swap with Galp Energia, under which TotalEnergies assumes operatorship of the neighbouring Mopane discovery (PEL 83) and Galp acquires a 10% interest in Venus (PEL 56). The transaction consolidates operatorship of Namibia's two largest offshore discoveries under TotalEnergies and supports the operator's stated strategy of pursuing a coordinated development approach across the Orange Basin.

The Company believes this alignment has the potential to create longer-term operational and infrastructure synergies across the basin while further reinforcing the strategic importance of the Venus development. Venus continues to be advanced as a standalone development on its own timeline, schedule and path to sanction. Longer-term basin synergies will be complementary to Venus.

TotalEnergies has also indicated that it is working towards sanction of the project in the coming months, with discussions with the Government of Namibia on the fiscal terms progressing and continues to present Venus among its expected 2026 FID.

The Company continues to regard its Namibian interests as a source of long-dated, low-cost production growth that diversifies its portfolio and strengthens its position in the Orange Basin, without upfront capital investment on the part of the Company.

SOUTH AFRICA ORANGE BASIN, BLOCK 3B/4B

On September 16, 2024, the Department of Mineral Resources and Energy for the Republic of South Africa granted an Environmental Authorization for exploration activities (drilling of up to 5 exploration wells) on the block. Following that decision, the legislative notification and appeals process in South Africa was suspended pending a Supreme Court of Appeal judgement in respect of Block 5/6/7. The suspension was lifted in March 2026 and on October 13, 2026, the Minister of Forestry, Fisheries and Environment delivered his decision to dismiss all appeals against the grant of the Environmental Authorization. Following the Minister's decision, interested parties have a period within which judicial review proceedings may be instituted. The operator has stated it currently plans to target the Nayla prospect for the first exploration well in Block 3B/4B, a prospect that lies in the northwest of the license area.

HIGHLIGHTS AND OUTLOOK - CONTINUED

EQUATORIAL GUINEA, BLOCKS EG-18 AND EG-31

The Company continues farm-down discussions on both blocks and remains focused on securing transactions that appropriately recognise the quality and strategic value of the assets while supporting its broader portfolio objectives. While engagement with potential counterparties continues, there can be no assurance that a transaction will be concluded.

In parallel, the Company continues to engage with the Ministry of Hydrocarbons, Mines and Electricity, GEPetrol and midstream stakeholders to advance negotiations on the regulatory terms and commercial framework required to support the future monetization of natural gas resources on Block EG-31.

SHAREHOLDER RETURNS

The Company is pleased to announce that its Board has declared the distribution of the Company's fourth quarterly cash dividend in 2026 of approximately $25.1 million or $0.0371 per share. This dividend will be payable to shareholders of record at the close of business on November 19, 2026.

Distributions continue to be set within the Company's capital allocation framework, balancing shareholder returns with investment in organic growth and maintaining a robust balance sheet. Future dividend declarations will be subject to customary Board approval and consents.

2026 MANAGEMENT GUIDANCE AND ACTUALS

The Company has revised full-year 2026 guidance, as summarised below and compared to the original guidance. The Company is on track to meet original production guidance with revised mid-points for EBITDAX and cash flow from operations that are above the upper end of the original guidance mid-points. The Company now expects full-year 2026 capital expenditure to be below the lower end of the original guidance of $100.0 million as some drilling activities are deferred into 2027.

	Original 2026 Guidance	Revised 2026 Guidance	9M 2026 Actuals
WI production (kboepd) [(1)]	23.0 - 28.0	25.0 - 27.0	26.9
Entitlement production (kboepd) [(2)]	28.0 - 33.0	29.0 - 31.0	29.8
EBITDAX ($ million) [(3)]	270.0 - 360.0	390.0 - 440.0	332.3
Cash flow from operations ($ million) [(3)]	185.0 - 255.0	250.0 - 280.0	213.0
Capital investments ($ million)	100.0 - 140.0	70.0 - 90.0	38.0

(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 September 30, 2026, are summarized in the following table:

Meren's Direct Working Interests [1]

Country	Concession	License renewal	Working Interests	
Nigeria	PML 52 [2]	November 24, 2044	Meren	8%
			Chevron (Operator)	32%
	PPL 2003 [2]	February 14, 2028	Famfa Oil	60% (carried)
	PML 2, 3, 4 [3]	May 24, 2043	Meren	32%
			TotalEnergies (Operator)	48%
	PPL 261 – PSA [3]	May 24, 2028	SAPETRO	20% (carried)
South Africa	Block 3B/4B	October 26, 2024 [4]	Meren	18%
			TotalEnergies (Operator)	33%
			QatarEnergy	24%
			Azinam	5.25%
			Ricocure (Pty) Ltd	19.75%
Equatorial Guinea	EG-18	March 1, 2027 [5]	Meren (Operator)	80%
			GEPetrol	20%
	EG-31	February 29, 2028	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 [6]	Impact	9.5%
			TotalEnergies	35.25%
			Galp	10%
			QatarEnergy	35.25%
			NAMCOR	10% (carried)
	PEL 91 (Block 2912)	October 1, 2027	Impact	9.5%
			TotalEnergies	33.09%
			Galp	9.39%
			QatarEnergy	33.02%
			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) 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.

(3) 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%.

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

(5) The Company has the option to extend the term of the first exploration sub-period of Block EG-18 by a further twelve months from March 1, 2027, to February 28, 2028 (inclusive), at its sole discretion.

(6) The Operator has submitted an application which extends the validity of the Exploration License. This is currently awaiting Government acknowledgement.

Information on the Company's equity interests in Africa Energy and Impact is included in "Equity Investments in Associates" on pages 18 - 19.

BUSINESS UPDATE

SHAREHOLDER RETURNS

The Company is pleased to announce that its Board has declared the distribution of the Company's fourth quarterly cash dividend of approximately $25.1 million or $0.0371 per share. This dividend will be payable to shareholders of record at the close of business on November 19, 2026.

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 December 4, 2026; 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 at the earliest on December 9, 2026.

To execute the payment of the dividend, a temporary administrative cross border transfer closure will be applied by Euroclear from November 17, 2026, up to and including November 19, 2026, 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/.

Notwithstanding the foregoing, the decision to declare any dividend or other shareholder distribution and the amount of future cash dividends declared and paid by Meren or shareholder distributions made by Meren, if any, will be subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time. These may include, without limitation, business performance, operating environment where Meren's assets are located, financial condition, growth plans, fluctuations in commodity prices, production levels, expected capital expenditure requirements, operating costs, royalties, foreign exchange rates, interest rates, compliance with any restrictions on the declaration and payment of dividends contained in any agreements to which Meren or any of its subsidiaries is a party from time to time (including, without limitation, financing agreements governing the RBL), and the satisfaction of liquidity and solvency tests imposed by the BC BCA for the declaration and payment of dividends. The actual amount, the record date and the payment date of any dividend are subject to the discretion of the Board. There can be no assurance that dividends will be paid at the current rate or at any rate in the future.

Pursuant to the Company's current Normal Course Issuer Bid ("NCIB") share repurchase program that was launched on December 8, 2025, 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 21,636,913 Common Shares of the Company for a total maximum amount of $35.0 million, which represented 5% of its "public float" of 432,738,277 Common Shares as at November 24, 2025. As of the same date, Meren had 675,725,593 Common Shares issued and outstanding.

Purchases of Common Shares may occur over a period of up to twelve months commencing December 8, 2025, and ending on the earlier of December 7, 2026, 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. Meren has not repurchased any shares since the renewal of its current NCIB program in December 2025.

GROUP OPERATIONS

PRODUCTION AND OPERATIONS

The comparative period production numbers as included in this section are no longer presented on a constructed financial information basis to be consistent with the comparative period financials as included in this Management's Discussion and Analysis that are derived from the interim condensed consolidated financial statements for the three and nine months ended September 30, 2025, and from the consolidated financial statements for the year ended December 31, 2025. Comparative period production numbers will therefore relate to the period since March 19, 2025, when the Company completed the transaction with BTG Oil & Gas to consolidate its interest in Meren Coop (the "Amalgamation") and will therefore be different compared to those presented in the Management's Discussion and Analysis for the nine months ended September 30, 2025, and for the year ended December 31, 2025.

Production Metrics – rounded

		Three months ended		Nine months ended		Year ended
	Unit	September 30, 2026	September 30, 2025	September 30, 2026	September 30, 2025	December 31, 2025
Total gross field production	boepd	207,200	250,100	214,900	250,800	237,000
Average daily WI production [1]	boepd	25,300	31,100	26,900	31,300	30,200
Average daily entitlement production	boepd	28,300	35,600	29,800	35,900	34,500
Oil volumes sold	MMbbl	2.0	3.0	5.0	5.0	8.0
Gas volumes sold	bcf	4.8	4.9	15.1	10.4	15.7
Oil/gas percentage split [2]	%	66%/34%	71%/29%	66%/34%	72%/28%	70%/30%

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

(2) Calculated on a working interest basis.

BUSINESS UPDATE - CONTINUED

Total gross field production in Q3 2026 was influenced by brief operational constraints at Akpo in early July and ongoing remedial work at Agbami in September, alongside natural reservoir decline. Performance strengthened as the quarter progressed, with both Akpo and Egina producing above plan by September.

At Akpo, production increased steadily through the quarter, supported by high plant reliability, exceeding plan by quarter end. Egina production remained stable, with strong uptime complemented by ongoing active reservoir management.

At Agbami, production remained at its highest levels of the year through July and August, building on the recovery following the late 2025 turnaround. In September, production was curtailed due to gas turbine compressor constraints, reducing gas injection. Work is being carried out to address these constraints, and the operator continues to advance its asset integrity programme, with the aim of improving gas compressor reliability.

In Q3 2026, two oil liftings were allocated to the Company with all-in realized oil prices of $90.2/bbl and $94.6/bbl respectively compared to a Dated Brent average of $86.9/bbl during July and August, when the cargoes were lifted.

In the first nine months of 2026, five oil liftings were allocated to the Company, with an average all-in realized oil price of $86.7/bbl, compared to a Dated Brent average of $93.9/bbl.

FINANCIAL

The comparative period numbers as included in this section are no longer presented on a constructed financial information basis. The comparative period numbers are derived from the interim condensed consolidated financial statements for the three and nine months ended September 30, 2025, and from the consolidated financial statements for the year ended December 31, 2025, as presented below. Comparative period numbers will therefore be different compared to those presented in the Management's Discussion and Analysis for the nine months ended September 30, 2025, and for the year ended December 31, 2025.

		Three months ended		Nine months ended		Year ended
	Unit	September 30, 2026	September 30, 2025	September 30, 2026	September 30, 2025	December 31, 2025
Revenue	$'m	192.4	216.7	503.4	362.4	559.9
Commodity risk management contracts	$'m	(35.3)	-	(62.6)	-	2.2
Movements on overlift/ underlift balances [1]	$'m	8.9	(37.3)	63.7	17.1	(46.3)
Production costs	$'m	(69.9)	(50.7)	(192.2)	(110.3)	(166.6)
Depletion costs	$'m	(43.1)	(73.0)	(137.6)	(155.0)	(207.9)
Impairment charges	$'m	-	-	-	-	(105.3)
Gross profit	$'m	53.0	55.7	174.7	114.2	36.0

(1) Given the nature of the Company's operations in terms of oil cargo liftings and the variability in their frequency from one quarter to the 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.

Revenues

		Three months ended		Nine months ended		Year ended
	Unit	September 30, 2026	September 30, 2025	September 30, 2026	September 30, 2025	December 31, 2025
Oil revenue	$'m	180.6	212.2	430.6	352.3	545.5
Gas revenue	$'m	11.8	4.5	72.8	10.1	14.4
Total revenue	**$'m**	**192.4**	**216.7**	**503.4**	**362.4**	**559.9**
Realized oil prices [1]	$/bbl	92.4	70.8	86.7	70.4	68.2
Oil volumes sold	MMbbl	2.0	3.0	5.0	5.0	8.0
Realized gas prices	$'m/bcf	2.5	1.0	2.1	1.0	0.9
Gas volumes sold	Bcf	4.8	4.9	15.1	10.4	15.7

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

BUSINESS UPDATE - CONTINUED

Oil revenue decreased in Q3 2026 compared with Q3 2025, mainly because there was one fewer cargo lifting despite a higher realized oil price of $92.4/bbl compared with $70.8/bbl in Q3 2025.

Oil revenue increased in the first nine months of 2026 compared with the same period in 2025, driven by a higher realized oil price of $86.7/bbl compared with $70.4/bbl in 2025.

During Q1 2025 prior to March 19 when the Company completed the Amalgamation, an additional 4 cargo liftings occurred with an average realized oil price of $80.5/bbl. See Management's Discussion and Analysis as per December 31, 2025, for more information.

The increase in gas revenue in the first nine months of 2026 compared to the first nine months of 2025 was primarily driven by the successful execution of an amendment to the gas sale agreement during Q1 2026 by the Company and its JV partners in PML 2/3. The amendment introduced a revised pricing index that better reflects prevailing LNG market economics than the pricing mechanism established when the contract was originally signed in 2018, thereby enhancing the long-term value of gas sales from the asset. The amendment also established a mechanism for the sellers to recover the historical difference between the interim gas price adjustment and the new pricing index from 2020, when the previous index ceased to be published. This historical amount will be recovered through an upward adjustment to future pricing, including the handling fee for the gas sold. As a result of the amendment, gas pricing was revised retrospectively from June 2025 and the Company recognized gas revenues of $13.7 million in the first nine months of 2026, primarily relating to the period from June 2025 onwards. In addition, the Company recognized a receivable of $27.1 million, representing the fair value of future recoveries relating to the period from 2020 to June 2025. The fair value was determined using a discount rate that reflects the credit risk of the counterparties to the agreement. In total, gas revenues recognized in the first nine months of 2026 in respect of the recovery mechanism under the amended gas sales agreement amounted to $40.8 million.

Excluding historical amounts recognized under the amended gas sale agreement, gas revenue for the first nine months of 2026 was $32.0 million, reflecting an increase from the first nine months of 2025 driven primarily by higher realized gas prices.

During Q1 2025, prior to the completion of the Amalgamation on March 19, 2025, the Company also recognized $4.7 million of gas revenue. See Management's Discussion and Analysis as per December 31, 2025, for more information.

Commodity risk management contracts

The Company has a direct interest in three producing fields within PMLs 2, 3 and 52, all with significant levels of production. Its strategy is to hedge between approximately 30-50% of its net entitlement production for the next 12 months. The derivatives held by the Company under its hedging strategy have been classified as a financial liability at fair value through profit or loss. As such, any gains or losses arising from changes in the fair value of these derivatives are taken directly to profit or loss which has resulted in primarily a non-cash charge to the income statement during Q3 2026 and the first nine months of 2026 of $35.3 million and $62.6 million, respectively, as a result of changing oil prices during the periods.

Movements on overlift/ underlift balances

During Q3 2026 Meren lifted two oil cargoes. As lifted oil volumes were lower than Meren's net entitlement oil production, this resulted in a net underlift movement compared to a net overlift movement in Q3 2025. During the first nine months of 2026 Meren lifted five oil cargoes. As lifted oil volumes were lower than Meren's net entitlement oil production, this resulted in a net underlift movement as was the case in the first nine months of 2025. During Q1 2025, prior to the completion of the Amalgamation on March 19, 2025, an additional 4 cargo liftings occurred resulting in a further overlift position for that quarter. See Management's Discussion and Analysis as per December 31, 2025, for more information.

Production costs

	Three months ended		Nine months ended		Year ended
$'m	September 30, 2026	September 30, 2025	September 30, 2026	September 30, 2025	December 31, 2025
Cost of operations	48.1	35.3	127.9	79.6	114.3
Royalties – oil and gas	16.2	10.6	47.4	22.1	29.4
Others	5.6	4.8	16.9	8.6	22.9
Total production costs	**69.9**	**50.7**	**192.2**	**110.3**	**166.6**

Production costs in Q3 2026 were higher compared to Q3 2025 primarily due to higher oil and gas prices resulting in higher royalty expenses and higher cost of operations mainly due to timing of routine maintenance and non-recurring operator personnel related costs.

Production costs reported in the table above were higher in the first nine months of 2026 compared to the first nine months of 2025, as the comparative period only includes production costs from March 19, 2025, following completion of the Amalgamation. Production costs incurred prior to the Amalgamation during Q1 2025, amounted to $52.3 million, resulting in total production costs for the first nine months of 2025 of $162.6 million. See Management's Discussion and Analysis as per December 31, 2025, for more information. Adjusting for this, production costs increased by $29.6 million, from $162.6 million in the first nine months of 2025 to $192.2 million in the first nine months of 2026, primarily reflecting higher royalty expenses associated with increased revenues and commodity prices and timing of routine maintenance and non-recurring operator personnel related costs.

Other costs of sales mainly relate to the NDDC Levy, which concerns the Niger Delta Development Commission Levy imposed to fund the sustainable development of the Niger Delta region, the HCDF Levy, which concerns the Host Communities Development Fund and other costs incurred in Nigeria.

BUSINESS UPDATE - CONTINUED

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		Nine months ended		Year ended
	Unit	September 30, 2026	September 30, 2025	September 30, 2026	September 30, 2025	December 31, 2025
Cost of operations	$'m	48.1	35.3	127.9	79.6	114.3
Entitlement production	MMboe	2.6	3.3	8.1	7.0	9.9
Opex/boe	**$/boe**	**18.5**	**10.7**	**15.8**	**11.4**	**11.5**

Opex/boe was $18.5/boe in Q3 2026, compared to $10.7/boe in Q3 2025 as a result of higher cost of operations, reflecting the timing of routine maintenance and non-recurring operator personnel related costs, and lower entitlement production volumes.

See Management's Discussion and Analysis as per December 31, 2025, for more information about opex/boe for the first nine months of 2025 including the period prior to March 19, 2025, when the Company completed the Amalgamation. Including the pre-Amalgamation period, opex/boe amounted to $11.8/boe in the first nine months of 2025. The increase from $11.8/boe in the first nine months of 2025 to $15.8/boe during the first nine months of 2026 was also driven by the higher cost of operations and lower entitlement production volumes.

Entitlement production is used as the denominator for this metric as cost of operations include carried costs that are recovered through entitlement production.

Cash flow from operations

Cash flow from operations before working capital is a non-GAAP measure. This represents cash generated by removing the impact of 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. When viewed in combination with the Company's results it 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		Nine months ended		Year ended
$'m	September 30, 2026	September 30, 2025	September 30, 2026	September 30, 2025	December 31, 2025
Cash flow from operations	72.7	146.7	112.6	193.5	178.6
Excluding working capital adjustments included in cash flow from operations	0.9	(81.1)	100.4	(33.6)	94.0
Cash flow from operations before working capital	**73.6**	**65.6**	**213.0**	**159.9**	**272.6**

Cash flow from operations before working capital in Q3 2026 was $73.6 million compared to $65.6 million in Q3 2025 as a result of lower taxes.

Prior to the completion of the Amalgamation on March 19, 2025, the Company generated additional cash flow from operations of $75.0 million during Q1 2025, resulting in total cash flow from operations of $268.5 million for the first nine months of 2025. In addition, cash flow from operations before working capital generated prior to the Amalgamation amounted to $100.7 million, resulting in total cash flow from operations before working capital of $260.6 million for the first nine months of 2025, compared to $213.0 million in the first nine months of 2026. The decrease in cash flow was primarily driven by lower entitlement revenues. See Management's Discussion and Analysis as per December 31, 2025, for more information.

BUSINESS UPDATE - CONTINUED

Free cash flow

Free cash flow is a non-GAAP measure. This measure represents cash flow from operating activities less net cash used in investing activities, before financing costs and shareholder distributions. It is a measure commonly used to assess the Company's cash generation.

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

		Three months ended		Nine months ended		Year ended
	Unit	September 30, 2026	September 30, 2025	September 30, 2026	September 30, 2025	December 31, 2025
Total cash flow	$'m	67.9	(89.9)	(29.1)	115.3	113.3
Add back dividends paid to shareholders	$'m	25.0	25.1	75.2	75.2	100.2
Add back repurchase of share capital	$'m	-	-	-	8.3	8.3
Add back debt service costs including drawdowns [1]	$'m	(33.8)	190.8	30.5	418.6	455.5
Free cash flow	**$'m**	**59.1**	**126.0**	**76.6**	**617.4**	**677.3**

(1) Debt service costs including drawdowns comprise interest payments, loan modification fees, repayments and drawdowns of third-party borrowings.

Free cash flow in Q3 2026 was $59.1 million compared to $126.0 million in Q3 2025. This was mainly driven by positive working capital movements in Q3 2025.

Free cash flow in the first nine months of 2025 included cash acquired as part of the Amalgamation of $380.4 million, $60.0 million in distributions received from Meren Coop prior to the completion of the Amalgamation on March 19, 2025, and distributions received from associated companies of $31.6 million. See Management's Discussion and Analysis as per December 31, 2025, for more information.

Tax

The tax expense is made up of the following items:

		Three months ended		Nine months ended		Year ended
	Unit	September 30, 2026	September 30, 2025	September 30, 2026	September 30, 2025	December 31, 2025
Current tax expense	$'m	41.8	56.1	101.6	80.5	135.9
Deferred tax expense/ (income)	$'m	(5.9)	(29.0)	9.7	(32.2)	(92.5)
Total tax	**$'m**	**35.9**	**27.1**	**111.3**	**48.3**	**43.4**

Current tax expense primarily comprises corporate income tax in Nigeria at a rate of 30.0% of assessable profits in Nigeria, the Development Levy (introduced in 2026) which is imposed on every Nigerian company at a rate of 4.0% of assessable profits and withholding tax on dividends. The Development Levy replaced the Education Tax and the NASENI Levy, which applied to every Nigerian company at a rate of 3.0% and 0.25% respectively, until December 31, 2025.

The tax charge exceeds income before tax for the first nine months of 2026 primarily because Nigerian taxes are levied at the Nigerian subsidiary level, while losses on commodity risk management contracts, the share of loss from investments in associates and the loss on RBL modification (Q3 2026 and first nine months of 2026 - $35.3 million and $85.7 million, respectively) do not attract tax relief.

BUSINESS UPDATE - CONTINUED

Capital expenditure

Capital expenditure is made up of the following items:

	Three months ended		Nine months ended		Year ended
$'m	September 30, 2026	September 30, 2025	September 30, 2026	September 30, 2025	December 31, 2025
Nigeria	11.6	20.6	32.7	51.9	69.2
Equatorial Guinea	2.8	1.2	5.1	3.8	6.6
South Africa	-	-	0.2	0.1	(0.2)
Total capex	**14.4**	**21.8**	**38.0**	**55.8**	**75.6**

Capital expenditure in Q3 2026 was $14.4 million compared to $21.8 million in Q3 2025, with the decrease reflecting the infill drilling programmes on Egina and Akpo undertaken during 2025.

Prior to the completion of the Amalgamation on March 19, 2025, the Company incurred additional capital expenditure of $24.6 million during Q1 2025, resulting in total capex for the first nine months of 2025 of $80.4 million. See Management's Discussion and Analysis as per December 31, 2025, for more information. Capital expenditure decreased from $80.4 million in the first nine months of 2025 to $38.0 million in the first nine months of 2026, primarily reflecting the significant investment made in the Egina and Akpo infill drilling programme during 2025.

Net Debt

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

	Nine months ended		Year ended
As at/ $'m	September 30, 2026	September 30, 2025	December 31, 2025
Loans and borrowings	330.8	360.0	330.0
Cash and cash equivalents	(145.6)	(176.7)	(174.7)
Net Debt	**185.2**	**183.3**	**155.3**

As at September 30, 2026, the Company had $145.6 million of cash and cash equivalents and $330.8 million of debt (as at December 31, 2025 - $174.7 million of cash and cash equivalents and $330.0 million of debt). During the first nine months of 2026, the Company refinanced its RBL facility and made net drawdowns of $0.8 million increasing outstanding debt to $330.8 million. The March 2026 RBL refinancing at improved terms, and the cancellation of the legacy corporate facility has resulted in the lowering of the Company's cost of debt.

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, impairment expenses, unrealized results on commodity risk management contracts and by adding back realized results on commodity risk management contracts. 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 leverage.

	Three months ended		Nine months ended		Twelve months ended	
$'m	September 30, 2026	September 30, 2025	September 30, 2026	September 30, 2025	September 30, 2026	December 31, 2025
Total profit/ (loss)	1.3	5.2	(9.1)	59.2	(99.9)	(31.6)
Add back:						
Tax	35.9	27.1	111.3	48.3	106.4	43.4
Share of result from investments in associates and joint venture	-	0.4	12.7	(0.5)	13.2	-
Finance costs	12.3	15.0	46.1	35.3	58.6	47.8
Finance income	(2.2)	(1.2)	(5.5)	(3.6)	(6.0)	(4.1)
Impairment charges/ (reversals)	-	-	-	(55.9)	105.3	49.4
Depletion, depreciation and amortization costs	43.3	73.3	138.5	155.7	191.8	208.9
Commodity risk management contracts	35.3	-	62.6	-	60.4	(2.2)
Realized result on commodity risk management contracts	(13.1)	-	(24.3)	-	(24.3)	-
EBITDAX	**112.8**	**119.8**	**332.3**	**238.5**	**405.5**	**311.6**
Net Debt					185.2	
Net Debt/ EBITDAX					**0.5**	

Net debt/ EBITDAX has been calculated on a rolling basis comprising Q4 2025 until Q3 2026 and is therefore not impacted by the first nine months of 2025 when the Company completed the Amalgamation on March 19, 2025.

Prior to the completion of the Amalgamation on March 19, 2025, the Company generated additional EBITDAX of $73.2 million during Q1 2025, resulting in total EBITDAX of $384.8 million for 2025.

EBITDAX no longer includes Meren's share of result from investments in associates and joint venture and related impairment reversals.

Crude Oil Marketing

The timing and frequency of cargo liftings may vary depending on a number of factors, including reservoir performance, realized oil prices, capex, opex, underlift/overlift positions and marine logistics. Reported revenues include cost oil, profit oil and, where applicable, royalty oil for each field.

For spot cargoes, the Dated Brent component of the sales price is not fixed in advance and is typically determined on or around the lifting date using mechanisms such as monthly average pricing, 5-days after the bill of lading date or other market-based mechanisms. The average cargo size is approximately one million barrels of oil.

Oil sales were comprised of the following:

		Three months ended		Nine months ended		Year ended
Oil Sales	Unit	September 30, 2026	September 30, 2025	September 30, 2026	September 30, 2025	December 31, 2025
Gross crude oil sales						
Quantity in Mboe	Mboe	1,956.0	3,000.5	4,963.0	5,004.7	8,007.0
Average sales price	$/bbl	92.4	70.8	86.7	70.4	68.2
Average Bloomberg Dated Brent for the period	$/bbl	97.0	69.1	93.9	70.9	69.1

BUSINESS UPDATE - CONTINUED

The Company sold 2 cargoes during Q3 2026 with an all-in price of $90.2/bbl and $94.6/bbl respectively.

During Q1 2025 prior to March 19, 2025, when the Company completed the Amalgamation, an additional 4 cargo liftings occurred with an average realized oil price of $80.5/bbl. See Management's Discussion and Analysis as per December 31, 2025, for more information.

Hedging

The Group's cash flow is exposed to fluctuations in the oil price. A decrease in oil price will lead to a reduction in oil revenue, and vice versa, but this is offset by an opposite movement in sales entitlement, royalties and taxes. The post-tax net entitlement production represents sales in respect of which the Group has physical price exposure.

The Group uses financial derivatives to manage its commodity price risk and ensure stability in cash flows, as outlined in the table below (as at the effective date of the MD&A). Its strategy is to hedge between approximately 30-50% of its net entitlement production for the next 12 months. A Q3 2026 derivative that was cash settled in early October is not included in the table below.

	Mbbl	Sold put $/bbl	Bought put $/bbl	Sold call $/bbl	Sold swap $/bbl
Q4 2026					
Swap	150	-	-	-	64.7
Three way put spread	450	45.0	60.0	65.8	-
Collar	150	-	60.0	74.0	-
Total	**750**				
H1 2027					
Swap	150	-	-	-	106.2
Collar	1,350	-	69.8	92.2	-
Total	**1,500**				
H2 2027					
Collar	750	-	69.5	94.0	-
Total	**750**				

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

The Company has direct interests in three producing fields, three undeveloped discoveries, and a 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 17 - 18 of the Company's Annual Information Form ("AIF") for the Year Ended December 31, 2025, for the detailed commercial information, and pages 39 - 48 of the same document for the detailed technical information on these assets. The AIF is available on SEDAR+ at www.sedarplus.ca or on the Company's website at www.mereninc.com.

BUSINESS UPDATE - CONTINUED

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. The Block 3B/4B legislative notification and appeals process, which had been suspended pending a Supreme Court of Appeal judgment in respect of Block 5/6/7, resumed in March 2026 and on October 13, 2026, the Minister of Forestry, Fisheries and Environment delivered his decision to dismiss all appeals against the grant of the Block 3B/4B Environmental Authorization. Following the Minister's decision, interested parties have a period within which judicial review proceedings may be instituted. The operator has stated it currently plans to target the Nayla prospect for the first exploration well in Block 3B/4B, a prospect that lies in the northwest of the license area.

Please refer to the Company's AIF for the year-ended December 31, 2025, 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.

On December 17, 2025, the Company received notification from the Ministry of Hydrocarbons and Mining Development in Equatorial Guinea approving extensions of up to two years to the first exploration sub period on each block.

The Company remains in active discussions with potential partners and continues to progress forward planning for both blocks.

Please refer to the Company's AIF for the year ended December 31, 2025, for further details on Blocks EG-18 and EG-31.

EQUITY INVESTMENTS IN ASSOCIATES

As at September 30, 2026, the Company held equity investments in two oil and gas companies, providing exposure to high-impact exploration opportunities in Namibia, together with additional exploration assets in South Africa.

The Company held the following equity investments in associates as of September 30, 2026:

	Africa Energy	Impact [1]
Issued and Outstanding	526,162,450	1,139,147,442
Shares held by Meren at December 31, 2025	55,396,483	449,464,396
Shares disposed in the period	(5,000,000)	-
Shares held by Meren at September 30, 2026	50,396,483	449,464,396
Meren's holding (%) – September 30, 2026	9.58%	39.46%
Meren's holding (%) – December 31, 2025	11.56%	39.46%
Share price (CAD) on September 30, 2026	0.21	
Exchange rate to USD on September 30, 2026	0.70	

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

Impact

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, 2025, for further details on the Company's shareholding in Impact and the supplementary technical and commercial information.

The Company, through its 39.5% shareholding in Impact Oil and 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's interest in these blocks (9.5%) is fully carried for all JV costs through an arrangement with TotalEnergies, through to first commercial production, without any financial cap.

On May 26, 2026, Impact announced a corporate restructuring to make Impact a pure-play Namibia focused development and exploration business. On completion of the restructuring, Impact's South African exploration interests will be separated out of Impact, removing the exposure to the costs of managing and maintaining the South African exploration assets, which are non-core to the Company. The restructuring is another step in the Company's strategy to simplify its business and high-grade its portfolio, whilst enhancing alignment with its core areas of value creation in the Orange Basin.

BUSINESS UPDATE - CONTINUED

Africa Energy

Following the sale of 5 million Africa Energy common shares on June 30, 2026, and Africa Energy's subsequent private placement of 47 million common shares, the Company held 50,396,483 common shares, representing approximately 9.6% of Africa Energy's outstanding common shares. The Company consequently ceased to be subject to early warning reporting requirements in respect of Africa Energy.

ENVIRONMENTAL, SOCIAL AND GOVERNANCE

The Company's Sustainability Strategy supports the Company's goal of the creation of long-term stakeholder value through aligning with or surpassing applicable regulatory requirements; building effective and adaptive risk management approaches; being a trusted partner for our stakeholders and a good neighbour to our local communities.

During Q3 2026 there were no reported material HSEC incidents.

GHG emissions during the reporting period were in line with operational forecasts. Flaring at the Agbami FPSO in Nigeria was in line with the interim flaring targets developed to take account of the process to re-establish stable production and flaring following the earlier turn-around maintenance. The Company undertook an assurance visit to the Agbami FPSO in September 2026 to facilitate ongoing engagement with the Operator.

Activities on the Company's development assets continued during the quarter, with no material developments requiring disclosure. In South Africa, all appeals against the Block 3B/4B Environmental Authorization were dismissed on October 13, 2026. Following that decision, interested parties have a period within which judicial review proceedings may be instituted. In Namibia, activities associated with the Venus development continued following submission of the Environmental and Social Impact Assessment (ESIA) to the relevant regulatory authorities, and the application for an Environmental Clearance Certificate remains under consideration.

The Company's 2025 Sustainability Report, published in May 2026, remains available on the Company's website and provides additional information on the Company's sustainability performance, management approach and strategic priorities.

SUMMARY OF QUARTERLY INFORMATION

All financial information included in the narrative discussion below is based on the Consolidated Statement of Net Income or Loss and Other Comprehensive Income or Loss and takes into account the Amalgamation closing on March 19, 2025.

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

For the three months ended	30-Sep 2026	30-Jun 2026	31-Mar 2026	31-Dec 2025	30-Sep 2025	30-Jun 2025	31-Mar 2025	31-Dec 2024
Revenue	192.4	196.7	114.3	197.5	216.7	69.3	76.4	-
Net income/ (loss) attributable to common shareholders ($'m)	1.3	31.8	(42.2)	(90.8)	5.2	3.1	50.9	6.2
Weighted average shares – Basic '000	676,115	676,115	675,944	675,686	675,513	675,012	468,472	442,690
Weighted average shares – Diluted '000	688,568	688,294	675,944	675,686	682,770	682,039	476,836	449,667
Basic income/ (loss) per share ($)	0.00	0.05	(0.06)	(0.13)	0.01	0.00	0.11	0.02
Diluted income/ (loss) per share ($)	0.00	0.05	(0.06)	(0.13)	0.01	0.00	0.11	0.02

SUMMARY OF KEY ITEMS OF FINANCIAL PERFORMANCE IN THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2026, AND SEPTEMBER 30, 2025

	Three months ended		Nine months ended	
	September 30, 2026	September 30, 2025	September 30, 2026	September 30, 2025
Revenue	192.4	216.7	503.4	362.4
Gross profit	53.0	55.7	174.7	114.2
General and administrative expenses	(5.7)	(9.2)	(19.2)	(31.4)
Net income/ (loss)	1.3	5.2	(9.1)	59.2

Revenue

Revenue in Q3 2026 and the first nine months of 2026 was $192.4 million and $503.4 million, respectively (Q3 2025 and the first nine months of 2025 – $216.7 million and $362.4 million, respectively).

Revenue in Q3 2026 was primarily generated from the sale of two cargoes at an average realized price of $92.4/bbl. The first nine months of 2026 also included the sale of two cargoes in Q2 2026 at an average realized price of $92.8/bbl and the sale of one cargo in Q1 2026 at a realized price of $63.7/bbl. Revenue in Q3 2025 was primarily generated from the sale of 3 cargoes at a realized price of $70.8/bbl. The first nine months of 2025 included the sale of two additional cargoes in H1 2025 at a realized price of $69.9/bbl.

Revenue from the sale of gas of $11.8 million and $72.8 million for Q3 2026 and the first nine months of 2026, respectively, (Q3 2025 and the first nine months of 2025 – $4.5 million and $10.1 million, respectively), reflected higher realized gas prices in both periods. Revenue for the first nine months of 2026 also included $40.8 million of gas revenue recognized under the recovery mechanism in the amended gas sales agreement.

Gross profit

Gross profit reported in Q3 2026 and the first nine months of 2026 was $53.0 million and $174.7 million, respectively (Q3 2025 and the first nine months of 2025 – $55.7 million and $114.2 million, respectively). Gross profit was impacted by changes in the fair value of oil derivative contracts resulting in primarily a non-cash charge to the income statement during Q3 2026 and during the first nine months of 2026 of $35.3 million and $62.6 million, respectively. Gross profit was also impacted by lower depletion costs in Q3 2026 and the first nine months of 2026 of $43.1 million and $137.6 million, respectively (Q3 2025 and the first nine months of 2025 - $73.0 million and $155.0 million, respectively) from lower production volumes, net underlift movements of $8.9 million and $63.7 million in Q3 2026 and the first nine months of 2026, respectively (Q3 2025 and the first nine months of 2025 – net overlift movement of $37.3 million and net underlift movement of $17.1 million, respectively) and higher production costs of $69.9 million and $192.2 million, respectively (Q3 2025 and first nine months of 2025 - $50.7 million and $110.3 million, respectively).

SUMMARY OF QUARTERLY INFORMATION - CONTINUED

General and administrative costs

On March 19, 2025, the Company announced the completion of the Amalgamation. 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 (a non-GAAP measure) by excluding the Amalgamation related expenses and is meant to improve comparability between periods. The Amalgamation related expenses also include certain LTIP charges for fully vested LTIP units as a result of the closing of the Amalgamation.

	Three months ended		Nine months ended	
	September 30, 2026	September 30, 2025	September 30, 2026	September 30, 2025
General and administrative expenses	5.7	9.2	19.2	31.4
Amalgamation related expenses	-	-	-	(9.0)
Adjusted general and administrative expenses	**5.7**	**9.2**	**19.2**	**22.4**

Adjusted general and administrative expenses in Q3 2026 and the first nine months of 2026 were $5.7 million and $19.2 million, respectively (Q3 2025 and the first nine months of 2025 - $9.2 million and $22.4 million, respectively). Share-based compensation charges in Q3 2026 and the first nine months of 2026 amounted to $2.2 million and $5.4 million, respectively (share based compensation not impacted by the closing of the amalgamation in Q3 2025 and the first nine months of 2025 – $1.3 million and $2.3 million, respectively). Share-based compensation expenses are impacted by movements in the share price of the Company and performance conditions.

Excluding share-based compensation charges, adjusted general and administrative expenses amounted to $3.5 million in Q3 2026, compared to $7.9 million in Q3 2025. The decrease was primarily attributable to lower personnel costs and cost allocations.

For the first nine months of 2026, adjusted general and administrative expenses, excluding share-based compensation charges, were $13.8 million, compared to $20.1 million in the first nine months of 2025. The decrease was also driven by lower personnel costs and cost allocations.

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

Net income/ (loss) as reported by the Company in its interim condensed consolidated financial statements can be impacted by items that are not reflective of the Company's underlying performance for the period. This may affect the comparability of the results of the Company between periods.

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

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

SUMMARY OF QUARTERLY INFORMATION - CONTINUED

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

		Three months ended		Nine months ended		Year ended
	Unit	September 30, 2026	September 30, 2025	September 30, 2026	September 30, 2025	December 31, 2025
Net income/ (loss)	**$'m**	**1.3**	**5.2**	**(9.1)**	**59.2**	**(31.6)**
Adjusted for:						
Impact of amended gas sales agreement [1]	$'m	1.7	-	(35.2)	-	-
Impairment charges	$'m	-	-	-	-	105.3
Commodity risk management contracts	$'m	35.3	-	62.6	-	(2.2)
Realized results on commodity risk management contracts	$'m	(13.1)	-	(24.3)	-	-
Result on RBL modification	$'m	-	-	10.4	-	-
Reversal of impairment investment in Meren Coop	$'m	-	-	-	(55.9)	(55.9)
Share of loss from investments in associates	$'m	-	0.4	12.7	2.4	2.9
Tax effects on adjustments	$'m	(0.5)	-	12.0	-	(31.6)
Adjusted net income/ (loss)	**$'m**	**24.7**	**5.6**	**29.1**	**5.7**	**(13.1)**
Adjusted net income/ (loss) attributable to common shareholders per share						
Basic		0.03	0.01	0.04	0.01	(0.02)
Diluted		0.03	0.01	0.04	0.01	(0.02)
Weighted average number of shares outstanding for the purpose of calculating adjusted net income/ (loss) per share						
Basic		676,115,307	675,512,565	676,058,682	607,202,542	624,464,015
Diluted		688,568,209	682,769,598	688,511,584	614,475,354	624,464,015

(1) In the first nine months of 2026, total gas revenues recognized under the amended gas sales agreement of $40.8 million offset against recovery of gas receivable of $5.6 million.

SUMMARY OF QUARTERLY INFORMATION - CONTINUED

SUMMARY OF KEY ITEMS OF FINANCIAL POSITION AS AT SEPTEMBER 30, 2026, AND DECEMBER 31, 2025

As at	September 30, 2026	December 31, 2025
Assets		
Oil and gas properties	1,308.6	1,413.5
Intangible exploration assets	49.0	43.7
Equity investments in associates	129.0	142.2
Cash and cash equivalents	145.6	174.7
Outstanding bank debt	330.8	330.0

Oil and gas properties

As at September 30, 2026, oil and gas properties amounted to $1,308.6 million (as at December 31, 2025 – $1,413.5 million) and related to the licenses PML 52 (covering part of the Agbami field), PML 2 (Akpo field), PML 3 (Egina field) and PML 4 (Preowei Field) in Nigeria. The portfolio continues to represent a substantial producing asset base, with the decrease primarily reflecting depletion associated with ongoing production, partially offset by capital expenditure in the assets.

Intangible exploration assets:

As at September 30, 2026, the carrying amount of the Company's intangible exploration assets in Equatorial Guinea was $29.6 million (as at December 31, 2025 – $24.5 million) and related to its 80% interest in Blocks EG-18 and EG-31.

As at September 30, 2026, the carrying amount of the Company's intangible exploration assets in South Africa was $19.4 million (as at December 31, 2025 - $19.2 million) and related to its 18.0% participating interest in the Block 3B/4B Exploration Right.

Equity investments in associates

As at September 30, 2026, the Company's investment in associates was $129.0 million (as at December 31, 2025 - $142.2 million), of which $128.0 million related to its investment in Impact and its interests in Blocks 2913B and 2912 in Namibia's Orange Basin. The decrease during the period primarily reflected the Company's share of the associates losses of $13.1 million, including approximately $10.5 million arising from an impairment recognized by Impact in certain non-Namibian oil and gas interests.

Cash and cash equivalents

As at September 30, 2026, the Company had $145.6 million cash and cash equivalents on hand, compared to a cash balance of $174.7 million as at December 31, 2025. The Company drew down $0.8 million on the RBL facility, paid $10.4 million of fees on the refinancing of the RBL, incurred capital and operational expenditure in respect of the licenses in Nigeria, Equatorial Guinea and South Africa, settled working capital balances, paid dividends to shareholders and incurred general and administrative costs.

Outstanding bank debt

Outstanding bank debt increased following drawdowns of $0.8 million under the refinanced RBL facility, increasing outstanding bank debt to $330.8 million as at September 30, 2026. The Company's headroom under the RBL facility at the end of Q3 2026 was $182.3 million.

LIQUIDITY AND CAPITAL RESOURCES

As at September 30, 2026, the Company had cash balances of $145.6 million and net working capital balances (including cash balances) of $82.2 million. Net working capital is calculated as current assets less current liabilities as presented in the consolidated balance sheet as per September 30, 2026. The Company's primary source of liquidity is operating income in Nigeria and the remaining undrawn amounts on the RBL.

RESERVES BASED LENDING FACILITY

On March 27, 2026, the Company successfully amended its Reserves Based Lending ("RBL") Facility, significantly increasing its debt capacity and extending its debt maturity profile. The RBL facility has a total commitment of $600.0 million with an accordion feature permitting an increase in the total facility size up to $1 billion. The total amount that can be drawn under the RBL facility 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 September 30, 2026, the BBA was $513.1 million (December 31, 2025 - $468.4 million), which will amortize as the RBL facility moves towards final maturity.

The amended RBL facility will accrue interest at the applicable SOFR rate plus 4.00% until March 27, 2029, increasing to 4.25% until final maturity on March 27, 2032. This represents a loan-life average margin reduction of 0.125% compared to the previous RBL facility terms. In addition, commitment fees of 40% of the margin are payable on the undrawn but available portion of the RBL facility, and commitment fees of 20% of the margin are payable on the unavailable portion of the RBL facility.

The RBL facility 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 facility lenders have security over cash and cash equivalents held in project accounts, receivables against cargoes sold and all relevant insurance policies of the three entities.

All financial and liquidity covenants covered by the RBL facility 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, 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 and nine months ended September 30, 2026.

In the event that the BBA reduces to an amount below the outstanding RBL facility balance, the Company would be required to repay the difference immediately.

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	676,115,307
Outstanding restricted share units	1,405,728
Outstanding performance share units	10,214,391
Full dilution impact on Common Shares outstanding	687,735,426

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 this increased to $43.4 million by December 31, 2025.

On June 25, 2021, Meren Nigeria 52 Limited (previously named Prime 127 Nigeria Limited) ("Meren 52"), a subsidiary of Meren Coop, signed a securitization agreement with two of the unit parties, Equinor and Chevron (the "Securitization Agreement"), whereby Equinor agreed to pay a security deposit to the two other JV parties to secure future payments due under that Securitization Agreement, pending a comprehensive resolution being reached among all unit parties in respect of the tract participation in the Agbami field by December 27, 2024. In accordance with the Securitization Agreement, on June 29, 2021, Meren 52 received from Equinor its portion of the security deposit in the form of a cash payment of $305.3 million. Meren 52 received an additional payment of $24.4 million on January 31, 2025, pursuant to the Securitization Agreement. Given no comprehensive resolution was reached by December 27, 2024, Meren 52 has recognized its portion of the security deposit and the additional receivable under the Securitization Agreement as other operating income on December 27, 2024. The process of implementing a new tract participation by the parties is ongoing and is subject to government approval. The parties will continue discussions to seek final resolution of the formal redetermination of the Agbami tract participation in respect of the period after December 27, 2024, however there is no certainty that such ongoing discussions will result in a final resolution.

Under the amended joint sale agreement between (among others) BTG Holding and the seller dated October 31, 2018, the seller could potentially claim that, given an additional payment has been received under the Securitization Agreement, this triggers a payment obligation of $54.6 million, exclusive of interest, capital taxes and certain deductions, contingent upon various criteria, with the outcome of this potential claim uncertain. Management considers the likelihood of any interest being payable to be unlikely. The Company has recorded an indemnity asset of $21.6 million under the deed of indemnity entered into between a subsidiary of the Company and BTG Oil & Gas on February 19, 2025, for any costs suffered or incurred above $33.0 million post completion of the Amalgamation, with the deed of indemnity backed by a $22.0 million letter of credit granted in favour of a subsidiary of the Company. The letter of credit will remain in place for an initial period of two years and if a claim is not resolved in two years or is made after the two year period BTG Oil & Gas has undertaken to extend or reinstate the letter of credit.

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 was received on September 18, 2025, and the Company subsequently transferred all of its rights and future obligations under Blocks 10BB, 13T and 10BA to its remaining joint venture party with effect on and from June 30, 2023. 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 September 30, 2026.

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 $126.5 million as at September 30, 2026, that are held within the project accounts in Nigeria and The Netherlands, proceeds from the oil cargoes 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.

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, contingent consideration arising from the acquisition of Meren Coop, oil and gas reserves used for depletion and impairment testing, decommissioning provisions, deferred tax and the valuation of overlift/underlift balances.

The Company's material accounting policies can be found in the Company's audited consolidated financial statements for the year ended December 31, 2025. There have been no changes to the critical accounting estimates since December 31, 2025.

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.

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 September 30, 2026, 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 September 30, 2026, 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 in the AIF could have a material adverse effect on the Company's business, financial condition, reserves and results of operations, such list being non-exhaustive.

Financial risks that can materially affect the figures presented and disclosed in the Financial Statements and MD&A are described in Note 26 to the interim condensed consolidated financial statements for the three and nine months ended September 30, 2026. All other risks that the Company is exposed to are described in the Company's Annual Information Form for the year ended December 31, 2025 ("AIF") available on SEDAR+ at www.sedarplus.ca or on Meren's website at www.mereninc.com/investor-summary/financial-reports-meetings-filings/.

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 these 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 addresses future conditions and events, it could involve risks and uncertainties including, but 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 shareholder distribution framework, distribution of special dividends and/or the implementation of share buy-backs;
- Planned exploration, appraisal and development activity including both expected drilling, and geological and geophysical related activities;
- Proposed development plans;
- Future development costs and the funding thereof;
- Expected funding and development costs;
- Asset integrity and life-extension programmes;
- 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;
- The Company's ability to successfully identify, complete and integrate potential acquisition opportunities;
- 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;
- The Company's plans and targets to reduce the Company's net emissions;
- Dates by which certain areas will be explored or developed or will come on stream or reach expected operating capacity;
- The Company's ability to comply with future legislation or regulations;

FORWARD-LOOKING STATEMENTS - CONTINUED

- Future staffing level requirements; and
- Changes to 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;
- Availability of financing;
- Uninsured risks;
- Changes in interest rates and foreign-currency exchange rates;
- Regulatory changes;
- Changes in the political or 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, the imposition of tariffs or changes in environmental or 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;
- Internal conflicts within states or regions;
- Dates by which certain areas will be explored or developed or will come onstream or reach expected operating capacity;
- The Company's ability to comply with future legislation or regulations;
- Future staffing level requirements; and
- Changes to any of the foregoing.

The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these factors are interdependent, and management's future course of action would depend on its assessment of all available information at that time. Although management believes that the expectations conveyed by the forward-looking statements are reasonable based on the information available to it on the date such forward-looking statements were made, no assurances can be given that such expectations will prove to be correct, and such forward-looking statements included in, or incorporated by reference into, this document should not be unduly relied upon.

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

INTERIM CONDENSED CONSOLIDATED STATEMENT OF NET INCOME OR LOSS AND OTHER COMPREHENSIVE INCOME OR LOSS

(Expressed in millions of United States dollars)

	Note	Three months ended		Nine months ended	
		September 30, 2026	September 30, 2025	September 30, 2026	September 30, 2025
Revenue	**4**	**192.4**	**216.7**	**503.4**	**362.4**
Commodity risk management contracts	26	(35.3)	-	(62.6)	-
Movements on overlift/underlift balances	5	8.9	(37.3)	63.7	17.1
Production costs	6	(69.9)	(50.7)	(192.2)	(110.3)
Depletion costs	12	(43.1)	(73.0)	(137.6)	(155.0)
Gross profit		**53.0**	**55.7**	**174.7**	**114.2**
General and administrative expenses		(5.7)	(9.2)	(19.2)	(31.4)
Operating income		**47.3**	**46.5**	**155.5**	**82.8**
Finance income	7	2.2	1.2	5.5	3.6
Finance expense	8	(12.3)	(15.0)	(46.1)	(35.3)
Net financial items		**(10.1)**	**(13.8)**	**(40.6)**	**(31.7)**
Share of profit from investment in joint venture		-	-	-	2.9
Share of loss from investments in associates	14	-	(0.4)	(12.7)	(2.4)
Reversal of impairment of investment in joint venture	9	-	-	-	55.9
Income before tax		**37.2**	**32.3**	**102.2**	**107.5**
Income tax	10	(35.9)	(27.1)	(111.3)	(48.3)
Net income/ (loss) attributable to common shareholders		**1.3**	**5.2**	**(9.1)**	**59.2**
Total comprehensive income/ (loss)		**1.3**	**5.2**	**(9.1)**	**59.2**
Net income/ (loss) attributable to common shareholders per share					
Basic	11	0.00	0.01	(0.01)	0.10
Diluted	11	0.00	0.01	(0.01)	0.10
Weighted average number of shares outstanding for the purpose of calculating earnings per share					
Basic	11	676,115,307	675,512,565	676,058,682	607,202,542
Diluted	11	688,568,209	682,769,598	676,058,682	614,475,354

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

INTERIM CONDENSED CONSOLIDATED BALANCE SHEET

(Expressed in millions of United States dollars)

As at	Note	September 30, 2026	December 31, 2025
ASSETS			
Non-current assets			
Oil and gas properties	12	1,308.6	1,413.5
Intangible exploration assets	13	49.0	43.7
Other tangible fixed assets		2.7	3.7
Equity investments in associates	14	129.0	142.2
Other long-term receivables	15	18.9	-
		1,508.2	**1,603.1**
Current assets			
Inventories	16	102.3	94.2
Trade and other receivables	15/17	122.6	77.7
Derivative financial instruments	26	-	2.2
Cash and cash equivalents	18	145.6	174.7
		370.5	**348.8**
Total assets		**1,878.7**	**1,951.9**
LIABILITIES AND EQUITY			
Equity attributable to common shareholders			
Share capital	19	1,536.6	1,536.2
Contributed surplus		95.5	95.5
Treasury share account		-	-
Deficit		(950.1)	(865.8)
Total equity attributable to common shareholders		**682.0**	**765.9**
Non-current liabilities			
Financial liabilities	20	332.8	265.2
Provisions	21	284.1	271.3
Deferred tax liabilities		291.5	281.8
		908.4	**818.3**
Current liabilities			
Financial liabilities	20	1.1	68.6
Trade and other payables	22	116.1	150.8
Derivative financial liability	26	39.2	-
Current tax liabilities		30.5	48.5
Provisions	21	101.4	99.8
		288.3	**367.7**
Total liabilities		**1,196.7**	**1,186.0**
Total liabilities and equity attributable to common shareholders		**1,878.7**	**1,951.9**

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

Approved on behalf of the Board:

"MICHAEL EBSARY"

MICHAEL EBSARY, DIRECTOR

"OLIVER QUINN"

OLIVER QUINN, DIRECTOR

INTERIM CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(Expressed in millions of United States dollars)

For the nine months ended	Note	September 30, 2026	September 30, 2025
Share capital:	19 (A)		
Balance, beginning of the period		1,536.2	1,195.8
Share issuance to BTG Oil & Gas under Amalgamation Agreement	19	-	353.2
Settlement of Restricted Share Units	19	0.1	1.1
Settlement of Performance Share Units	19	0.3	2.5
Weighted average value of shares cancelled	19	-	(16.8)
Balance, end of the period		**1,536.6**	**1,535.8**
Contributed surplus:			
Balance, beginning of the period		95.5	87.4
Excess of weighted value of shares cancelled	19	-	8.1
Balance, end of the period		**95.5**	**95.5**
Treasury share account:			
Balance, beginning of the period		-	(0.4)
Shares purchased	19	-	(8.3)
Shares cancelled	19	-	8.7
Balance, end of the period		**-**	**-**
Deficit:			
Balance, beginning of the period		(865.8)	(734.0)
Dividends	19	(75.2)	(75.2)
Net (loss)/ income attributable to common shareholders		(9.1)	59.2
Balance, end of the period		**(950.1)**	**(750.0)**
Total equity attributable to common shareholders			
Balance, end of the period		**682.0**	**881.3**

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

INTERIM CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS

(Expressed in millions of United States dollars)

	Note	Three months ended		Nine months ended	
		September 30, 2026	September 30, 2025	September 30, 2026	September 30, 2025
Cash flows generated by/ (used in):					
Operations:					
Profit before tax		37.2	32.3	102.2	107.5
Adjustments for:					
Reversal of impairment of investment in joint venture	9	-	-	-	(55.9)
Share of loss from investments in associates	14	-	0.4	12.7	2.4
Share of profit from investment in joint venture		-	-	-	(2.9)
Result on commodity risk management contracts	26	35.3	-	62.6	-
Settlement of commodity risk management contracts	26	(13.1)	-	(21.3)	-
Net financial items	7/8	10.1	13.8	40.6	31.7
Depletion, depreciation and amortisation	12	43.3	73.3	138.5	155.7
Share-based compensation		2.2	1.3	5.4	4.8
Recognized gas receivable	15	-	-	(27.1)	-
Taxes	10	(41.8)	(56.1)	(101.6)	(80.5)
Other		0.4	0.6	1.0	(2.9)
Net cash generated in operating activities before working capital		**73.6**	**65.6**	**213.0**	**159.9**
Changes in working capital		(0.9)	81.1	(100.4)	33.6
Net cash generated in operating activities		**72.7**	**146.7**	**112.6**	**193.5**
Investing:					
Investments in oil and gas properties and intangible exploration assets	12/13	(14.4)	(21.8)	(38.0)	(55.8)
Proceeds from disposal of shares in associates	14	-	-	0.5	-
Investments in other fixed assets		-	-	-	(0.4)
Distribution received from joint venture		-	-	-	60.0
Distribution received from associates	14	-	-	-	31.6
Loan repaid by / (provided to) associated company		-	-	-	4.5
Interest income received		0.8	1.1	1.5	3.6
Cash acquired from Meren Coop consolidation		-	-	-	380.4
Net cash (used)/ generated in investing activities		**(13.6)**	**(20.7)**	**(36.0)**	**423.9**
Financing:					
Drawdown/ (repayment) RBL Facility		40.8	(180.0)	0.8	(390.0)
RBL modification fees		-	-	(10.4)	-
Repayment of principal portion of lease commitments	20	(0.2)	(0.2)	(0.7)	(0.5)
Dividends paid		(25.0)	(25.1)	(75.2)	(75.2)
Repurchase of share capital	19	-	-	-	(8.3)
Interest expense paid		(6.8)	(10.6)	(20.2)	(28.1)
Net cash generated/ (used) in financing activities		**8.8**	**(215.9)**	**(105.7)**	**(502.1)**
Increase/ (decrease) in cash and cash equivalents		**67.9**	**(89.9)**	**(29.1)**	**115.3**
Cash and cash equivalents, beginning of the period	18	**77.7**	**266.6**	**174.7**	**61.4**
Cash and cash equivalents, end of the period	18	**145.6**	**176.7**	**145.6**	**176.7**

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

NOTES TO INTERIM CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

For the three and nine months ended September 30, 2026, and September 30, 2025
(Expressed in millions of United States dollars unless otherwise indicated)

1. Incorporation and nature of business:

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

2. Basis of preparation:

A. Statement of compliance:

The Company prepares its interim condensed consolidated financial statements in accordance with Canadian generally accepted accounting principles for interim periods, specifically International Accounting Standard ("IAS") 34 Interim Financial Reporting as issued by the International Accounting Standards Board. They are condensed as they do not include all the information required for full annual financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS Accounting Standards") and they should be read in conjunction with the consolidated financial statements for the year ended December 31, 2025.

The policies applied in these interim condensed consolidated financial statements are based on IFRS Accounting Standards and IAS 34.

These interim condensed consolidated financial statements were approved for issuance by the Company's Board of Directors on November 10, 2026.

B. Basis of measurement:

The interim condensed consolidated financial statements have been prepared on the historical cost basis. Where there are assets and liabilities calculated on a different basis, this fact is disclosed in the material accounting policy.

C. Functional and presentation currency:

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

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

D. Use of estimates and judgements:

The preparation of financial statements in conformity with IFRS requires management to make judgements, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates. Items subject to estimates and judgement have been described in the Company's audited consolidated financial statements for the year ended December 31, 2025.

E. Going concern

These interim condensed consolidated financial statements for the three and nine months ended September 30, 2026, have been prepared on a going concern basis, which assumes that the Company will be able to realize its assets and discharge its liabilities in the normal course of business as they become due.

3. Material accounting policies:

Material accounting policies used in the preparation of these interim condensed consolidated financial statements are described in the Company's consolidated financial statements for the year ended December 31, 2025.

On January 1, 2026, the Company adopted amendments to the Classification and Measurement of Financial Instruments – Amendments to IFRS 9 and IFRS 7. The amendments clarify that a financial liability is derecognized on the 'settlement date' and introduce an accounting policy choice to derecognize financial liabilities settled using an electronic payment system before the settlement date. Other clarifications include the classification of financial assets with ESG linked features via additional guidance on the assessment of contingent features. Clarifications have been made to non-recourse loans and contractually linked instruments. There was no material impact to the Company's financial statements.

On January 1, 2026, the Company adopted annual improvements to IFRSs: Volume 11. The amendments in Volume 11 focus on five key IFRS Accounting Standards. There was no material impact to the Company's financial statements.

Other new accounting standards and amendments to accounting standards have been published that are not mandatory for September 30, 2026, reporting periods and have not been early adopted by the Company. These are as follows:

- IFRS 18 Presentation and Disclosure in Financial Statements - on April 9, 2024, the International Accounting Standards Board (IASB) issued IFRS 18 Presentation and Disclosure in Financial Statements, which aims to improve how companies communicate their financial statements, with a focus on information about financial performance in the statement of profit or loss.

  The standard adds new subtotals, categories for income and expenses, and mandates disclosure of management performance measures. It also enhances rules around aggregation and disaggregation. Adoption is retrospective, and the Company is currently assessing system changes, preparing draft disclosures, and planning comparative restatements ahead of the January 1, 2027, effective date;

Apart from IFRS 18, these amendments are not expected to have a material impact on the Company in the current or future reporting periods and on foreseeable future transactions.

4. Revenue:

Revenue for the three and nine months ended September 30, 2026, and September 30, 2025, is comprised of the following:

	Three months ended		Nine months ended	
	September 30, 2026	September 30, 2025	September 30, 2026	September 30, 2025
Oil revenue	180.6	212.2	430.6	352.3
Gas revenue	11.8	4.5	72.8	10.1
Total revenue	**192.4**	**216.7**	**503.4**	**362.4**

In January 2026, the Company and its JV Parties in PML 2/3 successfully executed an amendment to the gas sales agreement that includes a revised index for gas pricing, locking a long-term gas price that is more reflective of the current LNG economics compared to 2018 when the contract was initially signed, resulting in the recognition of gas revenues of $40.8 million (see Note 15).

On March 19, 2025, the Company completed the transaction with BTG Oil & Gas to consolidate its interest in Meren Coop resulting in the comparative nine months period reflecting revenues since this date only.

5. Movements in overlift/ underlift balances:

The movement in overlift/ underlift balances for the three and nine months ended September 30, 2026, amounted to a profit of $8.9 million and $63.7 million respectively (three and nine months ended September 30, 2025 - loss of $37.3 million and profit of $17.1 million respectively) and related to the Group's excess of its entitlement production for the period over its crude oil sales during the period. Also refer to notes 17 and 22.

6. Production costs:

Production costs for the three and nine months ended September 30, 2026, and September 30, 2025, are comprised of the following:

	Three months ended		Nine months ended	
	September 30, 2026	September 30, 2025	September 30, 2026	September 30, 2025
Cost of operations	48.1	35.3	127.9	79.6
Royalties	16.2	10.6	47.4	22.1
Others	5.6	4.8	16.9	8.6
Total production costs	**69.9**	**50.7**	**192.2**	**110.3**

Cost of operations mainly relates to lifting costs from personnel, material and services from third parties.

On March 19, 2025, the Company completed the transaction with BTG Oil & Gas to consolidate its interest in Meren Coop resulting in the comparative nine months period reflecting production costs since this date only.

7. Finance income:

	Three months ended		Nine months ended	
	September 30, 2026	September 30, 2025	September 30, 2026	September 30, 2025
Interest income on cash and cash equivalents	0.6	1.2	1.5	3.4
Interest income from associated companies	-	-	-	0.2
Unwinding of loan modification result	0.9	-	1.7	-
Unwinding of receivables (see Note 15)	0.7	-	2.3	-
Total finance income	**2.2**	**1.2**	**5.5**	**3.6**

On March 19, 2025, the Company completed the transaction with BTG Oil & Gas to consolidate its interest in Meren Coop resulting in the comparative nine months period reflecting finance income since this date only.

8. Finance expense:

	Three months ended		Nine months ended	
	September 30, 2026	September 30, 2025	September 30, 2026	September 30, 2025
Interest expense on RBL	6.8	9.8	20.4	23.2
Commitment fees	0.8	1.2	2.9	3.0
Result on RBL modification	-	-	10.4	-
Amortisation of loan modification fees	0.9	-	1.7	-
Unwinding of site restoration provision	3.2	3.0	9.4	6.3
Others	0.6	1.0	1.3	2.8
Total finance expense	**12.3**	**15.0**	**46.1**	**35.3**

On March 19, 2025, the Company completed the transaction with BTG Oil & Gas to consolidate its interest in Meren Coop resulting in the comparative nine months period reflecting finance expenses since this date only.

9. Reversal of impairment of investment in joint venture:

On March 19, 2025, the Company completed the transaction with BTG Oil & Gas to consolidate its interest in Meren Coop. The transaction was originally announced on June 24, 2024. 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.

As at March 19, 2025, management determined there was objective evidence of impairment reversal based on the Meren share price when the Company announced the completion of the amalgamation. The fair value of the 50% shareholding in Meren Coop was calculated to be $327.8 million, resulting in a non-cash impairment reversal on the investment in Meren Coop of $55.9 million for the three months ended March 31, 2025.

10. Income tax:

	Three months ended		Nine months ended	
	September 30, 2026	September 30, 2025	September 30, 2026	September 30, 2025
Current tax expense	41.8	56.1	101.6	80.5
Deferred tax (income)/ expense	(5.9)	(29.0)	9.7	(32.2)
Total income tax	**35.9**	**27.1**	**111.3**	**48.3**

Current tax expense primarily comprises corporate income tax in Nigeria at a rate of 30.0% of assessable profits in Nigeria, the Development Levy (introduced in 2026) which is imposed on every Nigerian company at a rate of 4.0% of assessable profits and withholding tax on dividends. The tax charge exceeds income before tax for the nine months ended September 30, 2026, primarily because Nigerian taxes are levied at the Nigerian subsidiary level, while losses on commodity risk management contracts, the share of loss from investments in associates and the loss on RBL modification (the three months and nine months ended September 30, 2026 - $35.3 million and $85.7 million, respectively) do not attract tax relief.

On March 19, 2025, the Company completed the transaction with BTG Oil & Gas to consolidate its interest in Meren Coop resulting in the comparative nine months period reflecting taxes since this date only.

11. Net result per share:

For the three months ended	September 30, 2026			September 30, 2025		
		Weighted Average			Weighted Average	
	Net income	Number of shares	Per share amounts	Net income	Number of shares	Per share amounts
Basic income per share						
Net income attributable to common shareholders	1.3	676,115,307	0.00	5.2	675,512,565	0.01
Effect of dilutive securities	-	12,452,902	-	-	7,257,033	-
Dilutive income per share	**1.3**	**688,568,209**	**0.00**	**5.2**	**682,769,598**	**0.01**

For the nine months ended	September 30, 2026			September 30, 2025		
		Weighted Average			Weighted Average	
	Net loss	Number of shares	Per share amounts	Net income	Number of shares	Per share amounts
Basic (loss)/ income per share						
Net (loss)/ income attributable to common shareholders	(9.1)	676,058,682	(0.01)	59.2	607,202,542	0.10
Effect of dilutive securities	-	-	-	-	7,272,812	-
Dilutive (loss)/ income per share	**(9.1)**	**676,058,682**	**(0.01)**	**59.2**	**614,475,354**	**0.10**

In the three months ended September 30, 2026, no securities were anti-dilutive and in the nine months ended September 30, 2026, the Company made a loss and therefore all potential dilutive shares are considered antidilutive (three and nine months ended September 30, 2025, 320,387 options and 304,607 options, were anti-dilutive and not included in the calculation of dilutive income per share). Dilutive securities include share purchase options, RSUs and PSUs as the inclusion of these reduces the net income per share.

PSUs are awarded a performance multiple ranging from nil to 200% which leads to an increase in the dilutive and anti-dilutive potential of these instruments.

12. Oil and gas properties:

	Nigeria
Cost	
At January 1, 2025	-
Acquired under amalgamation	1,538.1
Remeasurement of site restoration provisions	119.4
Additions	69.2
At December 31, 2025	**1,726.7**
Additions	32.7
At September 30, 2026	**1,759.4**
Depletion and impairments	
At January 1, 2025	-
Depletion	(207.9)
Impairment charges	(105.3)
At December 31, 2025	**(313.2)**
Depletion	(137.6)
At September 30, 2026	**(450.8)**
Oil and gas properties as at September 30, 2026	**1,308.6**

As at September 30, 2026, oil and gas properties amounted to $1,308.6 million and related to the licenses PML 52 (covering part of the Agbami field), PML 2 (Akpo field), PML 3 (Egina field) and PML 4 (Preowei field) in Nigeria (as at December 31, 2025 - $1,413.5 million).

In the year ended December 31, 2025, the Company recognized a change in estimate of $119.4 million in oil and gas properties which related for $122.9 million to the remeasurement of the site restoration provisions acquired under the amalgamation in accordance with IAS 37 and for $3.5 million negative to the periodic re-assessment of variables such as projected decommissioning cost per well, discount rates and economic lives of the fields (see note 21).

The Company carries out impairment tests of individual cash-generating units when impairment triggers are identified.

As at December 31, 2025, the Company determined that there was an indicator of impairment in respect of its oil and gas properties related to the Agbami field CGU, reflecting a more conservative oil price and cost outlook compared to prior assumptions. This assessment was driven by oil price volatility at that time and updated cost forecasts. A significant portion of the revised cost outlook relates to planned long-term life-extension activities required to enable the Agbami FPSO to continue operating reliably and safely through the end of the current license period. The impairment does not reflect any adverse change in reservoir performance, reserves classification or the operational integrity of the Agbami field.

The Company calculated the recoverable amount of the CGU using a fair value less costs to dispose discounted cash flow model. The recoverable amount was determined using discounted future after tax net cash flows of proved and probable oil and gas reserves using forecast prices and costs prepared by management's expert at December 31, 2025. It was determined that the carrying value exceeded the recoverable value and non-cash impairment charges of $105.3 million were recognized on the Group's oil and gas properties related to the CGU.

As at September 30, 2026, the Company determined that there were no indicators of impairment or impairment reversal for its oil and gas properties.

13. Intangible exploration assets:

	Intangible exploration assets		
	Equatorial Guinea	South Africa	Total
At January 1, 2025	17.9	11.4	29.3
Additions	6.6	7.8	14.4
At December 31, 2025	**24.5**	**19.2**	**43.7**
Additions	5.1	0.2	5.3
At September 30, 2026	**29.6**	**19.4**	**49.0**

As at September 30, 2026, the carrying amount of the Company's intangible exploration assets in Equatorial Guinea was $29.6 million and related to its 80% interest in Blocks EG-18 and EG-31 (as at December 31, 2025 – $24.5 million).

As at September 30, 2026, the carrying amount of the Company's intangible exploration assets in South Africa was $19.4 million for its 18.0% (as at December 31, 2025 – 18.0%) participating interest in the Block 3B/4B Exploration Right (as at December 31, 2025 - $19.2 million).

As at September 30, 2026, the Company determined that there were no indicators of impairment for its intangible exploration assets.

14. Equity investments in associates:

The Company holds the following equity investments in associates:

	Africa Energy Corp.	Impact Oil and Gas Ltd	Total
Shares held at September 30, 2026	50,396,483	449,464,396	
Ownership at September 30, 2026	9.6%	39.5%	
At January 1, 2025	2.8	174.8	177.6
Share of loss from equity investments	(0.4)	(2.5)	(2.9)
Loss on dilution of equity investments	(0.9)	-	(0.9)
Distribution received	-	(31.6)	(31.6)
At December 31, 2025	**1.5**	**140.7**	**142.2**
Share of loss from equity investments	(0.4)	(12.7)	(13.1)
Disposal	(0.1)	-	(0.1)
At September 30, 2026	**1.0**	**128.0**	**129.0**

In the nine months ended September 30, 2026, the Company recognized a loss of $13.1 million (nine months ended September 30, 2025 – loss of $2.4 million). The Company also recognized a gain of $0.4 million in the nine months ended September 30, 2026, on shares in Africa Energy Corp. that were sold, resulting in a total loss from investments in associates of $12.7 million in the nine months ended September 30, 2026.

As at September 30, 2026, the Company determined that there were no indicators of impairment for its investments in Africa Energy Corp. or Impact Oil and Gas Ltd.

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

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

In the nine months ended September 30, 2026, the Company sold 5 million shares in Africa Energy at a share price of CAD 0.135.

As at September 30, 2026, the market value of the Company's investment in Africa Energy was $7.5 million based on the share price of CAD 0.21 (as at December 31, 2025 - $4.5 million). The carrying value is less than the market value as a result of significant impairments recognized by Africa Energy.

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

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

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

Impact recognized an impairment to its non-Namibia oil and gas interests of approximately $26.6 million with the Company's share of the loss being approximately $10.5 million which is included in share of loss from equity investments recognized of $12.7 million in the nine months ended September 30, 2026.

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

15. Other long-term receivables:

	Gas receivable
At January 1, 2026	-
Recognition of gas receivable	27.1
Recovery	(5.6)
Unwinding of discount	2.3
At September 30, 2026	**23.8**

Non-current	18.6
Current	5.2
At September 30, 2026	**23.8**

In January 2026, the Company and its JV Parties in PML 2/3 successfully executed an amendment to the gas sales agreement that includes a revised index for gas pricing, locking in a long-term gas price that is more reflective of the current LNG economics compared to 2018 when the contract was initially signed. The amendment also includes a mechanism for the sellers to recover the historical difference between the interim gas price adjustment and the new index, starting from 2020 when the previous index ceased to be published. This historical amount will be recovered through an upward adjustment to the pricing that includes the handling fee for the gas sold. The amendment to the gas sales agreement resulted in the immediate revision of the gas pricing retrospectively as from June 2025 with the Company recognizing gas revenues of $13.7 million primarily covering the period from June 2025. In addition, the Company calculated the fair value of the future upward adjustments to the net back pricing to cover the period from 2020 to June 2025 using a discount rate that considers the credit risk of the counterparties in the agreement resulting in the recognition of a receivable of $27.1 million. Total gas revenues recognized under the amended gas sales agreement therefore amounted to $40.8 million.

Other long term receivables also include $0.3 million in relation to other items.

16. Inventories:

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

17. Trade and other receivables:

	September 30, 2026	December 31, 2025
Trade receivables	9.2	5.6
Underlift position	56.9	12.2
Short-term receivables with partners	23.3	32.7
Prepaid expenses and accrued income	2.3	2.5
Gas receivable (see Note 15)	5.2	-
Other receivables	25.7	24.7
Total accounts receivable and prepaid expenses	**122.6**	**77.7**

The excess of entitlement production during the period over the volumes it has lifted is recognized by the Group as an underlift asset with a corresponding credit to movements on overlift/underlift balances. An underlift receivable is the right to receive oil out of the Group's equity share of future production.

The short-term receivables with partners mainly relate to the Group's share in the receivables of its joint operations in Nigeria.

Other receivables include an indemnity asset of $21.6 million recognized under the deed of indemnity entered into between the Company and BTG Oil & Gas (see Note 21).

18. Cash and cash equivalents:

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

19. Share capital and reserves:

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

B. Issued:

	September 30, 2026		December 31, 2025	
	Shares	Amount	Shares	Amount
Balance, January 1	675,909,193	1,536.2	439,078,170	1,195.8
Share issuance to BTG Oil & Gas under Amalgamation Agreement	-	-	239,828,655	353.2
Exercise of Share Options	-	-	367,600	0.4
Settlement of Restricted Share Units	26,332	0.1	836,323	1.1
Settlement of Performance Share Units	179,782	0.3	1,974,498	2.5
Cancellation of shares repurchased	-	-	(6,176,053)	(16.8)
Balance, end of the period	**676,115,307**	**1,536.6**	**675,909,193**	**1,536.2**

The Company launched a share buyback program on December 6, 2024, that ended on December 5, 2025. In the year ended December 31, 2025, a total of 5.9 million Meren common shares were repurchased and 6.2 million Meren common shares were cancelled. The Company launched a new share buyback program on December 8, 2025, under which no Meren common shares have been repurchased during the three and nine months ended September 30, 2026, and the year ended December 31, 2025.

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

In the three months ended March 31, 2026, the Board of Directors approved a dividend of $0.0371 per share which was declared in February 2026 and paid in April 2026 for a total amount of approximately $25.1 million.

In the three months ended June 30, 2026, the Board of Directors approved a dividend of $0.0371 per share which was declared in May 2026 and paid in June 2026 for a total amount of approximately $25.1 million.

In the three months ended September 30, 2026, the Board of Directors approved a dividend of $0.0371 per share which was declared in August 2026 and paid in September 2026 for a total amount of approximately $25.1 million.

20. Financial liabilities:

	Reserves Based Lending Facility	Lease Liability	Total
At January 1, 2025	-	3.3	3.3
Acquired under amalgamation	750.0	-	750.0
Initial recognition of IFRS 16 lease liability	-	1.1	1.1
Repayments	(420.0)	(0.6)	(420.6)
At December 31, 2025	**330.0**	**3.8**	**333.8**
Result on RBL modification	10.4	-	10.4
RBL modification fees	(10.4)	-	(10.4)
Unwinding of loan modification result	(1.7)	-	(1.7)
Amortisation of loan modification fees	1.7	-	1.7
Drawdowns/ (Repayments)	0.8	(0.7)	0.1
At September 30, 2026	**330.8**	**3.1**	**333.9**

Non-current	262.3	2.9	265.2
Current	67.7	0.9	68.6
At December 31, 2025	**330.0**	**3.8**	**333.8**

Non-current	330.8	2.0	332.8
Current	-	1.1	1.1
At September 30, 2026	**330.8**	**3.1**	**333.9**

A. Reserves Based Lending Facility

On March 27, 2026, the Company successfully amended its Reserves Based Lending ("RBL") facility, significantly increasing its debt capacity and extending its debt maturity profile. The RBL facility has a total commitment of $600.0 million with an accordion feature permitting an increase in the total facility size up to $1 billion. 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 at September 30, 2026, the BBA was $513.1 million, which will amortize as the RBL moves towards the final maturity date (as at December 31, 2025 - $468.4 million).

The amended RBL facility accrues interest at the applicable SOFR rate plus 4.00% until March 27, 2029, when it increases to 4.25% until final maturity on March 27, 2032. This represents a loan-life average margin reduction of 0.125% compared to the previous facility terms. 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 facility 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 cargoes sold and all relevant insurance policies of the three entities.

All financial and liquidity covenants covered by the RBL facility 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, 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 and nine months ended September 30, 2026.

In the event that the BBA reduces to an amount below the outstanding RBL facility balance, the Company will be required to repay the difference immediately.

As the amendment to the RBL facility did not result in a substantially different financial liability under IFRS 9, the modification was accounted for by adjusting the carrying amount of the RBL facility to reflect the net present value of the modified future cash flows, discounted at the original effective interest rate, with the resulting difference recognized as a modification loss of $10.4 million in finance expense.

The modification loss is primarily attributable to the transaction fees incurred on the amended RBL facility. When the Company acquired its interest in Meren Coop through the amalgamation with BTG Oil & Gas in March 2025, the RBL facility was recognized at fair value in accordance with IFRS 3, which resulted in no deferred transaction costs being carried on the balance sheet at the date of the refinancing. As a result, the full value of the new transaction fees is reflected in the modification loss. Fees incurred in connection with the refinancing have been capitalized and will be amortized over the remaining term of the RBL facility using the effective interest rate method.

21. Provisions:

	Site restoration	Contingent consideration	Share-based compensation	Others	Total
At January 1, 2025	5.7	40.4	7.3	-	53.4
Acquired under amalgamation	129.4	54.6	-	2.8	186.8
Changes in estimates	119.4	-	-	-	119.4
Charges	-	-	6.3	1.4	7.7
Unwinding of discount	9.2	2.9	-	-	12.1
Settlements	-	-	(8.3)	-	(8.3)
At December 31, 2025	**263.7**	**97.9**	**5.3**	**4.2**	**371.1**
Charges	-	-	5.4	0.6	6.0
Unwinding of discount	9.4	-	-	-	9.4
Settlements	-	-	(1.0)	-	(1.0)
At September 30, 2026	**273.1**	**97.9**	**9.7**	**4.8**	**385.5**

Non-current	263.7	-	3.4	4.2	271.3
Current	-	97.9	1.9	-	99.8
At December 31, 2025	**263.7**	**97.9**	**5.3**	**4.2**	**371.1**

Non-current	273.1	-	6.2	4.8	284.1
Current	-	97.9	3.5	-	101.4
At September 30, 2026	**273.1**	**97.9**	**9.7**	**4.8**	**385.5**

A. Site restoration

The provision for site restoration amounted to $273.1 million as at September 30, 2026 (as at December 31, 2025 - $263.7 million). The fair value of the provision for site restoration mainly relates to Nigeria and is based on the estimated future cash flows to decommission the oil and gas properties at the end of their useful life. The discount rate used to determine the net present value of the decommissioning obligation was 4.8% (as at December 31, 2025 – 4.8%) based on a risk-free rate with a similar maturity to that of the timing of the expected cash flows and a long-term inflation rate of 2.3% (as at December 31, 2025 – 2.3%).

In the year ended December 31, 2025, the site restoration provisions acquired under the amalgamation represented the present value of decommissioning costs relating to the acquired oil and gas properties, which are expected to be incurred up to the economic cut-off dates of the Agbami, Akpo and Egina fields. These provisions have been calculated based on the cash flow estimates as provided by the operators of the fields. The fair value of the site restoration provisions acquired on amalgamation totaling $129.4 million have been calculated using a credit-adjusted discount rate in accordance with IFRS 3, which has subsequently been re-measured using a risk-free rate in accordance with IAS 37 resulting in a change in estimate of $122.9 million. In addition, the Group revised its provision for decommissioning liabilities downwards by $3.5 million resulting from periodic re-assessment of projected decommissioning cost per well, discount rates and economic lives of the fields.

B. Contingent consideration

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 this increased to $43.4 million by December 31, 2025.

On June 25, 2021, Meren Nigeria 52 Limited (previously named Prime 127 Nigeria Limited) ("Meren 52"), a subsidiary of Meren Coop, signed a securitization agreement with two of the unit parties, Equinor and Chevron (the "Securitization Agreement"), whereby Equinor agreed to pay a security deposit to the two other JV parties to secure future payments due under that Securitization Agreement, pending a comprehensive resolution being reached among all unit parties in respect of the tract participation in the Agbami field by December 27, 2024. In accordance with the Securitization Agreement, on June 29, 2021, Meren 52 received from Equinor its portion of the security deposit in the form of a cash payment of $305.3 million. Meren 52 received an additional payment of $24.4 million on January 31, 2025, pursuant to the Securitization Agreement. Given no comprehensive resolution was reached by December 27, 2024, Meren 52 has recognized its portion of the security deposit and the additional receivable under the Securitization Agreement as other operating income on December 27, 2024. The process of implementing a new tract participation by the parties is ongoing and is subject to government approval. The parties will continue discussions to seek final resolution of the formal redetermination of the Agbami tract participation in respect of the period after December 27, 2024, however there is no certainty that such ongoing discussions will result in a final resolution.

Under the amended joint sale agreement between (among others) BTG Holding and the seller dated October 31, 2018, the seller could potentially claim that, given an additional payment has been received under the securitization agreement, this triggers a payment obligation of $54.6 million, exclusive of interest, capital taxes and certain deductions, contingent upon various criteria, with the outcome of this potential claim uncertain. Management considers the likelihood of any interest being payable to be unlikely. The Company has recorded an indemnity asset of $21.6 million under the deed of indemnity entered into between a subsidiary of the Company and BTG Oil & Gas on February 19, 2025, for any costs suffered or incurred above $33.0 million post completion of the amalgamation, with the deed of indemnity backed by a $22.0 million letter of credit granted in favour of a subsidiary of the Company. The letter of credit will remain in place for an initial period of two years and if a claim is not resolved in two years or is made after the two year period BTG Oil & Gas has undertaken to extend or reinstate the letter of credit.

22. Trade and other payables:

	September 30, 2026	December 31, 2025
Short-term payables with partners	84.2	97.9
Crude oil overlift payable	7.1	26.1
Accruals	22.8	24.0
Other payables	2.0	2.8
Total trade and other payables	**116.1**	**150.8**

The short-term payables with partners mainly relate to the Group's share in the payables of its joint operations in Nigeria.

The Group's excess of crude oil lifted during the period over its entitlement share of production, is recognized as a crude oil overlift payable balance with a corresponding charge to movements on overlift/underlift balances. An overlift liability is the obligation to deliver oil out of the Group's equity share of future production.

23. Commitments and contingencies:

A. Contingent consideration:

For information on the contingent consideration in relation to the historical acquisition of Meren Coop, refer to Note 21B.

B. Withdrawal from Kenya:

On May 23, 2023, the Kenya entities along with TotalEnergies submitted withdrawal notices to the remaining joint venture party on Blocks 10BB, 13T and 10BA in Kenya, to unconditionally and irrevocably, withdraw from the entirety of the JOAs and PSCs for these concessions. The Company concurrently submitted notices to Ministry of Energy and Petroleum, requesting the government's consent to transfer all of its rights and future obligations under the PSCs to its remaining joint venture party. Government consent to the transfer was received on September 18, 2025, and the Company subsequently transferred all of its rights and future obligations under Blocks 10BB, 13T and 10BA to its remaining joint venture party with effect on and from June 30, 2023. 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 September 30, 2026.

C. Securities and guarantees

Under the conditions of the RBL facility, the main security package is comprised of security over the shares, production assets, contracts and rights of the Nigerian entities Meren 52 and Meren 234, cash and cash equivalents in the amount of $126.5 million as at September 30, 2026, that are held within the project accounts in Nigeria and The Netherlands, proceeds from the oil cargoes 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.

24. Segment information:

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

For segment information about oil and gas properties and intangible exploration assets, see note 12 and 13.

25. Related party transactions:

There are no material related party transactions to report for the three and nine months ended September 30, 2026.

26. Financial risk management:

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

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

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

A. Credit risk:

Credit risk is the risk of loss if counterparties do not fulfill their contractual obligations. The majority of the Company's credit exposure relates to amounts due from the Company's joint ventures and amounts receivable from the sale of crude oil. Approximately 90% of the Company's crude oil is sold to customers rated A+/Aa2 by S&P/Moody's. All other oil sales are made to companies that are either investment grade, are a subsidiary of an investment grade entity, or have its payment obligations supported by a letter of credit or guarantee issued by an investment grade entity. The risk of the Company's joint venture parties defaulting on their obligations per their respective joint operating and farmout agreements is mitigated as there are contractual provisions allowing the Company to default joint venture parties who are non-performing and reacquire any previous farmed out working interests. The maximum exposure for the Company is equal to the sum of its cash and accounts receivable. As at September 30, 2026, the Company held $6.7 million (as at December 31, 2025 - $15.9 million) of cash in financial institutions outside of Canada, the Netherlands and the UK.

B. Liquidity risk:

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

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

At September 30, 2026, the Company had $145.6 million of cash and cash equivalents and $182.3 million of the RBL facility available which provides the liquidity to fund operations and allows for increased liquidity if required for operations and acquisitions. The RBL facility matures on March 27, 2032, but amortizes each quarter as per the lower of commitments and the BBA.

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

In relation to the amounts drawn under the RBL facility as at September 30, 2026, the Company has no liabilities that mature on September 30, 2027, based on the currently approved BBA profile, subject to the results of the next redetermination. An amount of $73.3 million will mature between one year and two years, with the remaining balance of $257.5 million due between two and five years.

C. Market risk:

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

i. Foreign currency exchange rate risk:

The Company is exposed to changes in foreign exchange rates as expenses in international subsidiaries, oil and gas expenditures, or financial instruments may fluctuate due to changes in rates. The Company's exposure to foreign currency exchange risk is mitigated by the fact that the Company sources the majority of its capital projects and expenditures in US dollars. The Company has not entered into any instruments to manage foreign exchange risk.

ii. Interest rate risk:

The RBL facility has a variable interest rate, that is referenced to Secured Overnight Financing Rate ("SOFR") and exposes the Company to interest rate risk when drawn.

Management considers the Group's exposure to interest rate risk to be related to the RBL facility principal amount of $330.8 million. As such, the Group has substantial floating-rate borrowings which are partially offset by cash held at variable rates. Therefore, a change in interest rates at the reporting date is likely to affect profit and loss of the Group. The Group's financing agreements make reference to SOFR. Also refer to note 20 to these interim condensed consolidated financial statements.

iii. Commodity price risk:

The Company has a direct interest in three producing fields within PMLs 2, 3 and 52, all with significant levels of production. Its strategy is to hedge between approximately 30-50% of its net entitlement production for the next 12 months. The counterparties are part of groups with investment grade credit ratings.

As at September 30, 2026, the Company holds derivatives, as outlined in the table below, that are classified as a financial liability at fair value through profit or loss. The derivatives are valued using Level 2 inputs. As such, any gains or losses arising from changes in the fair value of these derivatives are recognized directly in profit or loss. The fair value of these derivatives as per September 30, 2026, amounted to $39.2 million negative and included $3.0 million negative for a Q3 2026 derivative that was cash settled early October and that is not included in the table below.

	Mbbl	Sold put $/bbl	Bought put $/bbl	Sold call $/bbl	Sold swap $/bbl
Q4 2026					
Swap	150	-	-	-	64.7
Three way put spread	450	45.0	60.0	65.8	-
Collar	150	-	60.0	74.0	-
Total	**750**				
H1 2027					
Collar	1,200	-	67.8	90.9	-
Total	**1,200**				
H2 2027					
Collar	600	-	68.1	92.8	-
Total	**600**				

27. Subsequent events:

On November 10, 2026, the Company's Board declared the fourth quarterly dividend in 2026 of approximately $25.1 million ($0.0371 per share) payable in December 2026 to shareholders of record at the close of business on November 19, 2026.

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