Meren

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

Annual Information Form

For the Year Ended December 31, 2025

YE 25

February 24, 2026

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GLOSSARY

A	"Africa Energy"	means Africa Energy Corp.
	"AIF"	means this annual information form
	"Amalgamation Agreement"	means the definitive agreement between the Company, BTG Oil & Gas and BTG Holding, the entity which holds the interests of BTG Oil & Gas in Meren Coop (formerly known as Prime Coöperatief U.A.), to reorganize and consolidate their respective 50:50 shareholdings in Meren Coop
	"AOKBV"	means Africa Oil Kenya B.V.
	"Azinam"	means Azinam Limited, a wholly owned subsidiary of Eco
B	"BC BCA"	means the Business Corporations Act (British Columbia) S.B.C. 2002 c.57, as amended
	"Bcf"	means billion cubic feet
	"Board"	means the board of directors of the Company
	"bopd"	means barrels of oil per day
	"boepd"	means barrels of oil equivalent per day
	"BTG Holding"	means BTG Pactual Holding S.à.r.l.
	"BTG Oil & Gas"	means BTG Pactual Oil & Gas S.à.r.l.
	"BTG Pactual"	means Banco BTG Pactual S.A.
	"BTG Transaction"	means the transaction with BTG Oil & Gas and BTG Holding to consolidate its interest in Meren Coop (previously known as Prime Oil & Gas Coöperatief U.A)
C	"Carry Effective Date"	means January 1, 2024
	"Chevron"	means Chevron Corporation and subsidiaries
	"Concession"	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
	"Corporate Facility"	means the facility dated October 20, 2022 which was cancelled on May 22, 2025
E	"E&P"	means exploration and production
	"Eco "	means Eco (Atlantic) Oil & Gas Ltd.
	"Equinor"	means Equinor ASA
F	"Famfa Oil"	means Famfa Oil Ltd.
	"FEED"	means front-end engineering and design
	"FDP"	means field development plan
	"FPSO"	means floating production storage and offloading vessel
G	"GEPetrol"	means Guinea Equatorial De Petróleos, the National Oil Company of Equatorial Guinea
I	"Impact"	means Impact Oil and Gas Limited, a privately owned exploration company with an asset base across the offshore margins of Southern and West Africa
	"Investor Rights Agreement"	means the investor rights agreement between the Company and BTG Oil & Gas dated June 23, 2024
J	"JV Party" or "JV Parties"	means joint venture party or parties

M	"Mcf"	means million cubic feet
	"Meren", "MER", or the "Company"	means Meren Energy Inc. (previously known as Africa Oil Corp.)
	"Meren 52"	means Meren 52 Nigeria Limited (previously known as Prime 127 Nigeria Limited)
	"Meren Coop" or "Meren Coöperatief"	means Meren Coöperatief U.A., previously known as Prime Oil & Gas Coöperatief U.A., a company that holds interests in deepwater Nigeria production and development assets
N	"Nasdaq Stockholm"	means Nasdaq Stockholm exchange
	"NI 51-101"	means the 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 52-110"	means the National Instrument 52-110 - Audit Committees of the Canadian Securities Administrators and the companion policies and forms thereto, as amended from time to time
	"NNPC"	means NNPC Staff Cooperative Multipurpose Society Limited
O	"Offtake Agreement"	means the offtake agreement (as amended from time to time) between Meren Coop and SWST dated July 1, 2021
P	"petroleum operations"	means all exploration, gas marketing, development, production and decommissioning operations, as well as any other activities or operations directly or indirectly related to or connected with said operations (including health, safety and environmental operations and activities) and authorized or contemplated by, or performed in accordance with a Concession
	"PIA"	means Petroleum Industry Act
	"PML"	means petroleum mining lease
	"PML 2, 3, 4"	means the petroleum mining leases 2, 3, 4 and one petroleum prospecting license 261 which were converted under the new PIA regime in Q2 2023 from oil mining lease 130 and contain the Akpo, Egina and Preowei fields
	"PML 52"	means the petroleum mining lease 52 which was converted under the new PIA regime in Q3 2023 from oil mining lease 127 and contains the Agbami field
	"PPL"	means petroleum prospecting license
	"PPT"	means profit petroleum tax
	"PSA"	means petroleum sharing agreement
	"PSC"	means production sharing contract
	"PSU"	means performance share unit
R	"RBL"	means reserves based lending
	"RSU"	means restricted share unit
S	"SAPETRO"	means South Atlantic Petroleum
	"SWST"	means Shell Western Supply and Trading Limited
T	"TotalEnergies"	means TotalEnergies SE and subsidiaries
	"TSX"	means Toronto Stock Exchange
	"TUPNI"	means Total Upstream Nigeria Limited
U	"US"	means United States
V	"VAT"	means value-added tax
	"Venus First Oil Date"	means the date on which Impact receives the first sales proceeds from oil production on Blocks 2912 and 2913B, offshore Namibia
W	"WI"	means working interest

ABOUT THIS ANNUAL INFORMATION FORM

INTRODUCTION

All information contained in this AIF is as of December 31, 2025, unless otherwise indicated.

FINANCIAL INFORMATION

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

Meren's functional and reporting currency is the United States dollar. All currency amounts in this AIF are expressed in United States dollars, unless otherwise indicated.

PRESENTATION OF OIL AND GAS INFORMATION

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

CAUTIONARY STATEMENT ON FORWARD-LOOKING INFORMATION

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 continuation of the base dividend policy, 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;
- 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;

ABOUT THIS ANNUAL INFORMATION FORM - CONTINUED

- 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;
- 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 on stream 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 AIF 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 AIF, 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.

Cautionary Statements Regarding Oil and Gas Information

The terms boe (barrel of oil equivalent) and MMboe (millions of barrels of oil equivalent) are used throughout this AIF. 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 (1Bbl: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. The estimates of the reserves presented in this AIF have been evaluated by RISC (UK) Limited in accordance with NI 51-101 and the COGE Handbook and are effective December 31, 2025. The reserves presented herein have been categorized in accordance with the reserves and resource definitions as set out in the COGE Handbook. The estimates of reserves in this AIF may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation.

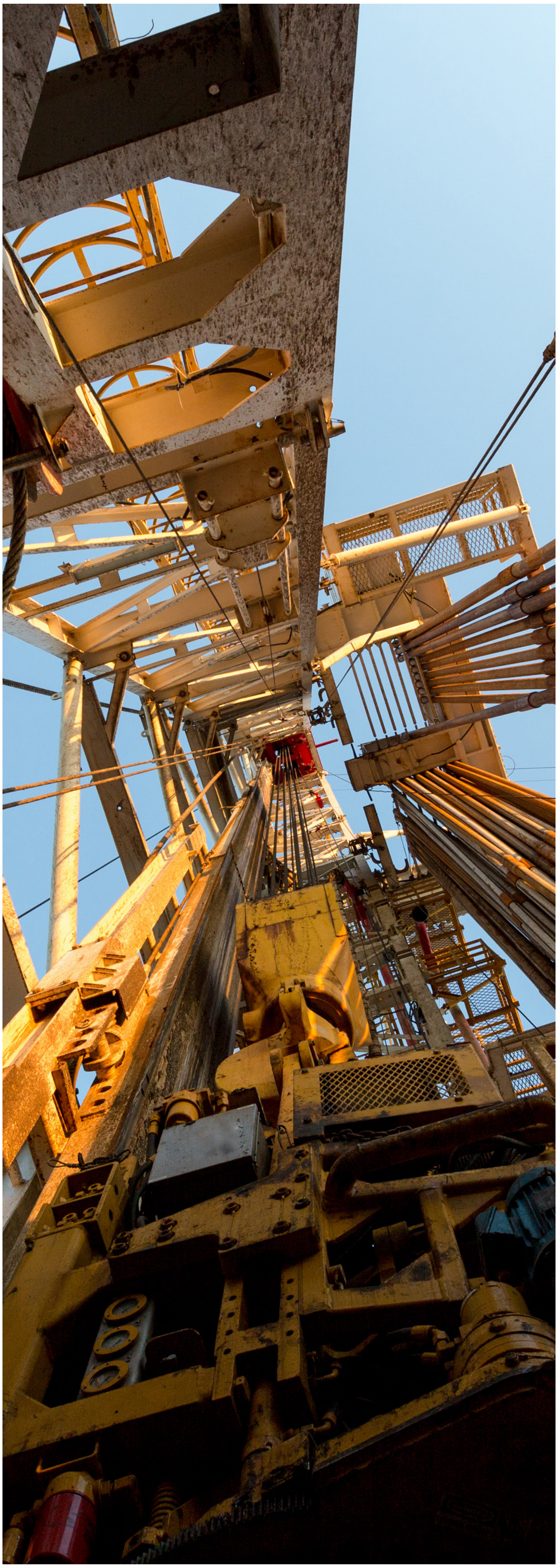
ABOUT THIS ANNUAL INFORMATION FORM - CONTINUED

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.

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technologies under development but are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include, but are not limited to, economic, contractual, environmental, technical, social and political factors, regulatory matters, a lack of markets, and a prolonged timetable for development. Contingent Resources are estimated using the same methods used for Reserves and require the same technical due diligence as Reserves, but they are generally estimated earlier in the life of a Resource when there may be little or no production data or limited analogue information. If this is the case, there may be significant uncertainty regarding key input parameters (such as porosity, hydrocarbon saturation, net pay thickness, and recovery factors) and a high range of uncertainty in the resulting estimated volumes. Contingent Resources have a Chance of Development that is less than certain. Contingent Resources are further categorized according to the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. The high confidence categories of Proved Reserves (1P) and low estimate Contingent Resources (1C) have the same levels of confidence with respect to the estimated volumes. Similarly, Proved + Probable Reserves (2P) and best estimate Contingent Resources (2C) are best case estimates that satisfy the same levels of confidence with respect to the estimated volumes. Likewise, the low confidence categories of high case estimates of Proved + Probable + Possible Reserves (3P) have the same levels of confidence as high estimate Contingent Resources (3C).

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by applying future development projects. Not all exploration projects will result in discoveries. Prospective Resources have both an associated Chance of Discovery and a Chance of Development. The Chance on Commerciality of a Prospective Resource is the product of the Chance of Discovery and the Chance of Development. Prospective Resources are typically estimated volumetrically using a combination of analogy, with geophysics and geology to estimate the Undiscovered Petroleum Initially in Place and reservoir engineering to identify a recovery process and a range of recoverable volumes. Probabilistic methods are typically employed to incorporate the uncertainty in all input parameters. Prospective Resources are further categorised according to the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub- classified based on project maturity to provide a low estimate, best case estimate and high case estimate of Prospective Resources.



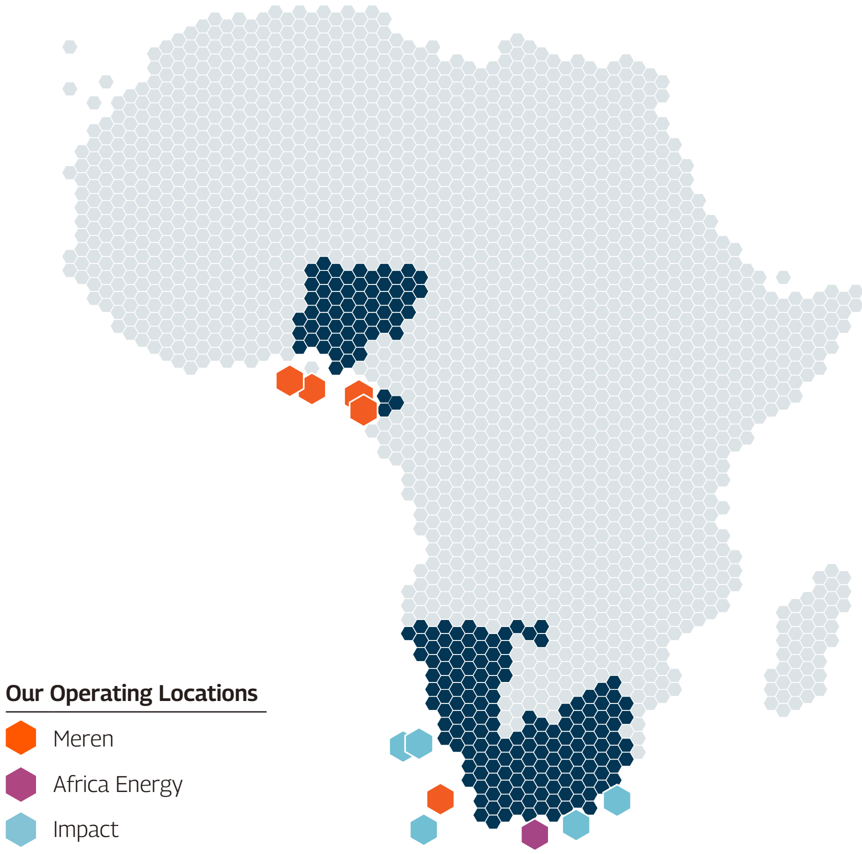
ABOUT MEREN

Focused on Long Term Value Creation and Sustainable Total Shareholder Returns

Meren is a full-cycle independent upstream oil and gas company with interests offshore Nigeria, Namibia, South Africa and Equatorial Guinea. Its main assets are producing and development assets in deepwater Nigeria. The Company holds a leading position in the Orange Basin including its effective interest in the Venus light oil project, offshore Namibia, and its direct interest in Block 3B/4B offshore South Africa.

Meren's long-term plan is to deliver growth and long-term value from its core assets to anchor sustainable total shareholder returns, whilst maintaining a strong balance sheet and minimum liquidity that provides for a resilient business through the cycle. This plan is supported by the Company's high netback production assets in Nigeria that are included in its interests in PMLs 2, 3 and PML 52. These PMLs provide the Company with a long-life cash flowing asset base, to support its business objectives over the long term, and together with Meren's interests in PML 4, PPLs 261 and 2003 present development opportunities for supporting future production.

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



ABOUT MEREN - CONTINUED

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 discovery offshore Namibia. The Venus discovery, understood to be the largest oil discovery globally in 2022, has partially de-risked a new petroleum province in the Orange Basin that has significant prospectivity.

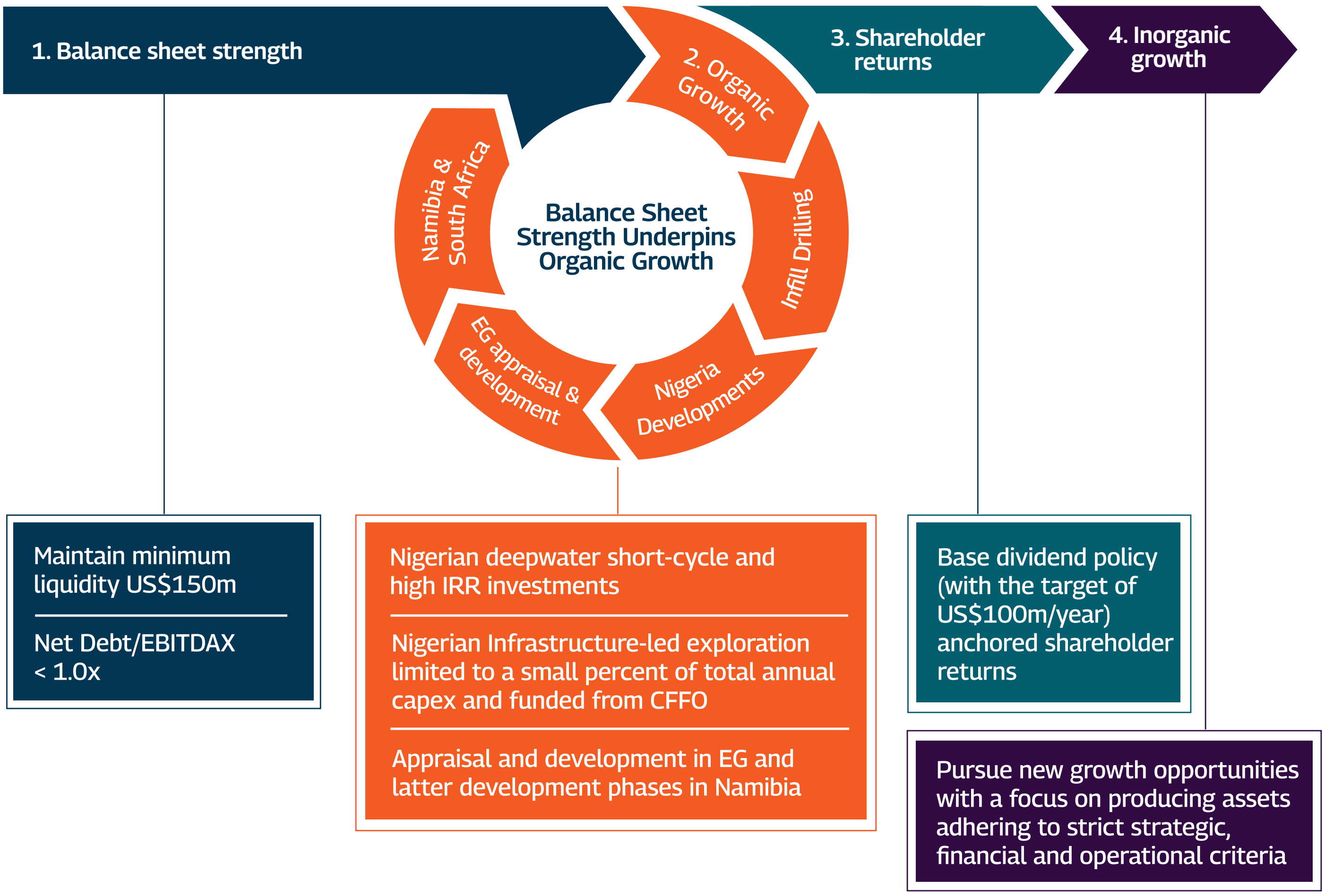
2025 HIGHLIGHTS

Closed the amalgamation transaction to take full control of Meren Coop, doubling Meren's reserves and production.

Returned approximately $108.6 million to shareholders through the base dividend policy and share buybacks.

Reduced the RBL debt balance by $420.0 million, reducing interest expenses and ending 2025 with a debt balance of $330.0 million and a Net Debt / EBITDAX of 0.4x.

Announced the new brand identity with a change of name from 'Africa Oil Corp.' to 'Meren Energy Inc.', marking the transformational Prime amalgamation deal.



CORPORATE STRUCTURE

INTRODUCTION

Meren is a Canadian oil and gas company with producing and development assets in deepwater Nigeria. The Company also has a portfolio of development and exploration assets in west and south of Africa. The Company holds its interests through direct ownership interests in Concessions and through its shareholdings in investee companies Impact Oil and Gas Ltd. and Africa Energy Corp. See 'Assets' on page 17 for more information on the Company's equity interests in Impact and Africa Energy. The Company's material interests, and material exploration interests as at December 31, 2025 are summarized in the following table:

Meren's Direct Working Interests [1]

Country	Concession	License renewal	Working Interests	
NIGERIA	PML 52 and PPL 2003 [2]	November 24, 2044	MER	8%
			Chevron (Operator)	32%
			Famfa Oil	60% (carried)
	PML 2, 3, 4 and PPL 261 - PSA [3]	May 24, 2043	MER	32%
			TotalEnergies (Operator)	48%
			SAPETRO	20% (carried)
SOUTH AFRICA	Block 3B/4B	October 26, 2024 [4]	MER	18%
			TotalEnergies (Operator)	33%
			QatarEnergy	24%
			Azinam	5.25%
			Ricocure (Pty) Ltd	19.75%
EQUATORIAL GUINEA	EG-18	March 1, 2027 [5]	MER (Operator)	80%
			GEPetrol	20%
	EG-31	February 29, 2028	MER (Operator)	80%
			GEPetrol	20%

Meren's Shareholding in Impact (39.5%)

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

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

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

INCORPORATION

Meren Energy Inc. was incorporated under the BC BCA on March 29, 1993, under the name 'Canmex Minerals Corporation' with an authorized capital of 100,000,000 common shares. On July 2, 1999, the issued and outstanding common shares of the Company were consolidated on a one-for-five basis and the authorized capital was increased, post-consolidation from 20,000,000 to 100,000,000 common shares. On August 20, 2007, the Company changed its name to 'Africa Oil Corp.' On June 19, 2009, the shareholders of the Company passed a special resolution increasing the Company's authorized share capital to an unlimited number of common shares. On June 3, 2013, the shareholders of Meren passed a special resolution authorizing an alteration of the Company's articles to include advance notice provisions for the nomination of directors. On May 14, 2025, the Company changed its name to 'Meren Energy Inc.'

THE COMPANY'S OFFICES AND TRANSFER AGENT

The common shares of the Company trade on the TSX and on the Nasdaq Stockholm under the trading symbol 'MER' and on the OTCQX Best Market ("OTCQX") in the U.S. under the ticker 'MRNFF'. The transfer agent and registrar of the Company's common shares in Canada is Computershare Investor Services Inc., 3rd Floor, 510 Burrard Street, Vancouver, British Columbia, V6C 3B9.

The registrar for the common shares of the Company in Sweden is Euroclear Sweden AB, 103 97 Stockholm, Sweden.

Meren's registered and records office is located at 25th Floor, 666 Burrard Street, Vancouver, B.C., V6C 2X8. The Company also has offices located at 50 Pall Mall, London SW1Y 5JH, England and at Weena 505, 3013AL, Rotterdam, The Netherlands.

EMPLOYEES

As of December 31, 2025, Meren had 1 employee located in Canada, 1 employee located in Kenya, 2 employees located in Equatorial Guinea, 7 employees located in the Netherlands, 10 employees located in Nigeria and 29 employees located in the UK, being a total of 50 employees.

INTERCORPORATE RELATIONSHIPS

The material subsidiaries owned by Meren, held either directly or indirectly, as at December 31, 2025, are shown below.

Subsidiary Name	Jurisdiction	Percentage Owned
Meren SA Energy Corp.	British Columbia, Canada	100%
Meren Nigeria Overseas Corp.	British Columbia, Canada	100%
Meren Services Limited	England & Wales	100%
Meren International Holdings B.V.	Netherlands	100%
Meren Holdings B.V.	Netherlands	100%
Meren Coöperatief U.A.	Netherlands	100%
Africa Oil Alpha B.V.	Netherlands	100%
Africa Oil Beta B.V.	Netherlands	100%
Meren Nigeria 52 Limited	Nigeria	100%
Meren Nigeria 234 Limited	Nigeria	100%

GENERAL DEVELOPMENT OF THE BUSINESS

THREE YEAR HISTORY

Over the three most recently completed financial years, the events below contributed to the development of the Company's business.

2023

In February 2023, the Company signed two production sharing contracts with the Republic of Equatorial Guinea for offshore Blocks EG-18 and EG-31, which were subsequently ratified on March 1, 2023. The Company holds an 80% operated interest in each Block with the balance held by GEPetrol, the national oil company of Equatorial Guinea. GEPetrol's 20% of joint venture costs are carried until approval of a development plan, at which point GEPetrol has 90 days to exercise its option to acquire an additional 15% participating interest in each Block.

In February 2023, the Company announced drilling operations, which commenced on the Venus-1A appraisal well in Block 2913B (PEL 56) located offshore Namibia and operated by TotalEnergies. A multi-well campaign on these Blocks commenced on March 4, 2023, targeting up to four wells (including the re-entry of the Venus-1X discovery well, in Block 2913B), to appraise the Venus discovery and to investigate a potential westerly extension of Venus, the Nara prospect on Block 2912. As at February 2023, the Company had an interest in this program through its 30.9% shareholding in Impact, which in turn had a 20.0% WI in PEL 56 and a 18.9% WI in PEL 91, giving Meren effective interests at that time of 6.2% and 5.8% in these licenses respectively.

In March 2023, the Company declared a semi-annual dividend of $0.025 per share (approximately $11.6 million) to be paid on March 31, 2023, to shareholders.

On April 27, 2023, the Company subscribed for 39,455,741 shares in Impact for $31.4 million, payable in two tranches, increasing the Company's shareholding in Impact to 31.1%. The first tranche of $14.9 million was paid on April 27, 2023, and the final tranche of $16.5 million was paid on July 21, 2023. On October 6, 2023, the Company subscribed for 16,524,058 shares in Impact for $13.0 million and directly following the transaction the Company increased its holding to approximately 31.1% of the enlarged share capital in Impact.

In May 2023, AOKBV, Meren along with TotalEnergies submitted withdrawal notices to the remaining JV 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 the Ministry of Energy and Petroleum, requesting the government's consent to transfer all of its rights and obligations under the PSCs to its remaining JV Party. In accordance with the JOA and PSC, the Company retains economic participation for activities prior to June 30, 2023.

In May 2023, OML 130, offshore Nigeria (which at the time was held indirectly by the Company through its 50% investment in Meren Coop) was renewed for a period of 20 years, securing the Company's long term production base and enabling the refinancing of Meren Coop's debt. The renewal was accompanied by a conversion of OML 130 to operate under Nigeria's new Petroleum Industry Act. Renewal of the rights under OML 130 also resulted in the award of three new petroleum mining leases and one petroleum prospecting license. These cover some of the areas previously covered by OML 130, with some of the areas also relinquished. These are PML 2 (Akpo field), PML 3 (Egina), PML 4 (Preowei) and PPL 261 (South Egina).

OML 127 was converted in Q3 2023, which also resulted in the new designation of PML 52 for the license area that contains part of the Agbami oil field. Both OML 130 and OML 127 are now subject to a 30% Corporate Income Tax regime compared to the previous 50% Petroleum Profit Tax regime.

During the three months ended June 30, 2023, the Company satisfied the conditions precedent to increase its existing Corporate Facility to $200.0 million from $100.0 million. $200.0 million of the Corporate Facility was available until October 20, 2023, and was not drawn. $175.0 million was available from October 20, 2023 until April 20, 2024.

On June 26, 2023, the Company announced the retirement of Mr. Keith Hill from his executive role at Meren and the appointment of Dr. Roger Tucker as the new President and Chief Executive Officer of the Company. Mr. Hill remained on the Board as a Director of the Company following his retirement with Dr. Tucker also joining the Board as a Director. The handover became effective on July 17, 2023.

On July 11, 2023, the Company entered into an agreement with Azinam to increase its operated working interest in Block 3B/4B in South Africa by 6.25% to 26.25%. Under the terms of the agreement, a wholly owned subsidiary of Eco, the Company agreed to acquire the 6.25% interest for a total cash consideration of $10.5 million. The first tranche of $2.5 million was paid during 2023. The transaction completed on January 22, 2024.

In October 2023, the Company announced the appointment of Dr. Oliver Quinn and Ms. Joanna Kay. Dr. Quinn was appointed as Chief Commercial Officer of the Company and Ms. Kay as Chief Legal Officer and Corporate Secretary of the Company.

On December 6, 2023, the Company launched a NCIB share buyback program. Pursuant to the NCIB, Meren was authorized to repurchase through the facilities of the TSX, Nasdaq Stockholm and/or alternative Canadian trading systems, up to 38,654,702 common shares of the Company, which represented 10% of its "public float" of 386,547,028 common shares as at November 27, 2023, over a period of up to twelve months, ending on the earlier of December 5, 2024, the date on which the Company purchased the maximum number of Common Shares permitted under the NCIB, and the date on which the NCIB was terminated by Meren.

During 2023, the Company received 3 dividend payments from its then 50% shareholding in Meren Coop totaling a net payment to the Company of $175.0 million.

2024

On January 10, 2024, the Company announced a strategic farm down agreement between its investee company, Impact, and TotalEnergies. Following the closing of this transaction, which was announced on November 1, 2024, Impact retained a 9.5% interest in Blocks 2912 and 2913B, offshore Namibia that is fully carried for all joint venture costs, with no cap, through to first commercial production. Impact also received a cash reimbursement of approximately $99.0 million for its share of the past costs incurred on the Blocks net to the farmout. The 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 ("Carry Effective Date"), until the date on which Impact receives the first sales proceeds from oil production on the Blocks ("Venus First Oil Date"). On and from the Venus First Oil Date, the carry is repayable to TotalEnergies in kind from 60% of Impact's after-tax cash flow net of all joint venture costs, including capital expenditures. During the repayment of the carry, Impact will pool its entitlement barrels with those of TotalEnergies for more regular off-takes and a more stable cashflow profile and will also benefit from TotalEnergies' marketing and sales capabilities.

On January 22, 2024, the Company announced the completion of the acquisition of a 6.25% working interest in Block 3B/4B South Africa from Azinam. A second tranche of $2.5 million was paid to Eco as consideration for the transfer following the completion of the acquisition. As a result, following completion the Company held an operated 26.25% interest in Block 3B/4B with Eco retaining a 20.00% interest and Ricocure (Pty) Ltd with a 53.75% interest.

In March 2024, the Company declared a semi-annual dividend of $0.025 per share (approximately $11.5 million) which was paid on March 28, 2024.

On March 6, 2024, the Company announced its wholly-owned subsidiary, Africa Oil SA Corp. had signed a strategic farm down agreement with TotalEnergies and QatarEnergy for Block 3B/4B, offshore South Africa. The completion of the transaction was announced on August 28, 2024. Meren retained a 17.00% interest and the operatorship of Block 3B/4B transferred to TotalEnergies for a total consideration of $46.8 million.

On March 18, 2024, the Company announced an offer to acquire up to 8.0% of the issued shares in Impact from its minority shareholders. On August 19, 2024, the Company announced the closing of the offer to purchase 25,652,039 shares in Impact from 42 accepting minority shareholders, increasing the Company's shareholding in Impact to approximately 32.4%.

In May 2024, the Company announced the appointment of Mr. Michael Ebsary as Director of the Company, in replacement of Mr. Ian Gibbs who stepped down from the Board.

On May 21, 2024, the Company amended its existing Corporate Facility, the availability under the Corporate Facility was $65.0 million until June 30, 2025, $43.0 million from July 1, 2025, until June 30, 2026, and $22.0 million from July 1, 2026, to May 21, 2027, i.e. its new final maturity date.

On June 23, 2024, the Company entered into the Amalgamation Agreement with BTG Oil & Gas and BTG Holding to consolidate its interest in Meren Coop (previously known as Prime Oil & Gas Coöperatief U.A) (the "BTG Transaction"). The BTG Transaction is described in more detail in 'Significant Acquisitions' on page 13.

On August 27, 2024, the Company signed a call and put option agreement with three shareholders in Impact to purchase an additional 80,160,198 shares in Impact ("Option Agreement"). Meren served the notice to exercise the call option on November 5, 2024, and announced the completion of the transaction on November 21, 2024. Following completion, the Company's shareholding in Impact increased to approximately 39.5%. The total cost for the purchase was approximately $68.8 million.

In September 2024, the Company declared a semi-annual dividend of $0.025 per share for a total amount of $11.1 million which was paid on September 27, 2024.

On November 1, 2024, the Company announced that the Nigerian Upstream Petroleum Regulatory Commission ("NUPRC") had renewed the term of PML 52, containing the Agbami field, for a period of 20 years, effective from November 24, 2024.

On December 4, 2024, the Company renewed its NCIB share buyback program. Pursuant to the NCIB, Meren was authorized to repurchase through the facilities of the TSX, Nasdaq Stockholm and/or alternative Canadian trading systems, up to 18,362,364 common shares of the Company for a total maximum amount of CAD 35 million, which represented 5% of its "public float" of 367,247,289 common shares as at November 22, 2024, over a period of up to twelve months, commencing on December 6, 2024 and ending on the earlier of December 5, 2025, the date on which the Company purchased the maximum number of Common Shares permitted under the NCIB, and the date on which the NCIB was terminated by Meren.

During December 2024, the Company received several approvals from the Ministry of Hydrocarbon and Mining Development (MHMD) in relation to the Blocks the Company holds in Equatorial Guinea. On December 2 and 5, the Company was granted a 1-year extension to the first exploration sub period on EG-31 and EG-18 respectively. The license periods for both Blocks, EG-18 and EG-31, are valid until March 1, 2026. On December 23, the Company received approval of the first amendment to the EG-31 PSC which extended the Block boundary to ensure the full extent of the two main prospects are located within the revised Block boundary.

During 2024, the Company received two dividend distributions from its then 50% shareholding in Meren Coop, totaling a net payment to the Company of $36.0 million.

2025

On January 13, 2025, the Company announced the completion of a transaction with Eco to acquire an additional 1.0% interest in Block 3B/4B from Azinam in exchange for all common shares and warrants over common shares held by the Company in Eco. Following this transaction, the Company's interest in Block 3B/4B increased by 1.0% to 18.0% and the Company ceased to be a shareholder in Eco.

On January 29, 2025, the Company received a dividend from its investee company, Impact of approximately $31.6 million. The dividend followed Impact's receipt of $99 million from TotalEnergies upon completion of the farm down transaction for Blocks 2912 and 2913B offshore Namibia in November 2024.

On March 19, 2025, the Company completed the BTG Transaction. The BTG Transaction is described in more detail in 'Significant Acquisitions' on page 13. On completion of the BTG Transaction, Messrs. Keith Hill, Andrew Bartlett and Gary Guidry and Ms. Erin Johnston, stepped down from the Board and Mr. Nicodeme stepped down as the Chief Financial Officer of the Company. Messrs. Huw Jenkins (new non-executive Chair), Edwyn Neves, Ahonsi Unuigbe and Richard Norris joined the Board and Mr. Aldo Perracini was appointed as Chief Financial Officer, pursuant to BTG Oil & Gas' nomination rights under the Investor Rights Agreement. Mr. Nicodeme assumed the role of director of the Board.

Also on March 19, 2025, the Company declared its first quarterly dividend of $0.0371 per share (approximately $25 million) which was paid on April 11, 2025. This dividend formed part of the Company's new base dividend policy targeting annual distributions of at least $100 million. Quarterly dividends were declared in each subsequent quarter of 2025, each of $0.0371 per share, resulting in total dividends of approximately $100.2 million.

On April 28, 2025, the Company provided an operational update on the Marula-1X drilling operation on Block 2913B (PEL 56), offshore Namibia. The Marula-1X well was drilled to a measured depth of 6,460 metres on Block 2913B, targeting Albian-aged sandstones within the Marula fan complex. No hydrocarbons were encountered, and no drill stem test was conducted.

On May 15, 2025, the Company announced its new brand identity with a change of name from 'Africa Oil Corp.' to 'Meren Energy Inc.'. Following the rebrand, the Company trades under the ticker **"MER"** on both the TSX and Nasdaq Stockholm. This rebrand followed the completion of the Prime consolidation and reflected the Company's evolution from exploration-led to a full-cycle E&P, bolstered by enhanced scale, cashflow, and shareholder returns.

On June 30, 2025, the Company announced that Mr. John Craig had stepped down from the Company's Board and was replaced by Ms. Cheryl Sandercock.

On September 2, 2025, the Company announced that Mr. Craig Knight stepped down as Chief Operating Officer. To streamline its organization, the Company combined the Chief Commercial Officer and Chief Operating Officer roles in a new role of Chief Commercial & Operating Officer, assumed by Dr. Oliver Quinn. The Company also appointed Mr. Thomas Haffenden as an officer of the Company in the role of Chief Human Resources Officer.

On November 7, 2025, the Company announced that its common shares had been qualified to trade on the OTCQX Best Market in the United States under the ticker **"MRNFF"**.

On December 4, 2025, the Company renewed its NCIB share buyback program. Pursuant to the NCIB, Meren was authorized to repurchase, through the facilities of the TSX, Nasdaq Stockholm and/or alternative Canadian trading systems, up to 21,636,913 common shares of the Company for a total maximum amount of CAD 35 million, which represented 5% of its "public float" of 432,738,277 common shares as at November 24, 2025, over a period of up to twelve months, commencing on 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.

RECENT DEVELOPMENTS

In January 2026, Meren 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 netback pricing that includes the handling fee for the gas sold.

On February 2, 2026, the Company announced the resignation of Dr. Roger Tucker as a director and as President and Chief Executive Officer of Meren. On the same date, Dr. Oliver Quinn was appointed as the new President and Chief Executive Officer of the Company and joined the Board as a director.

On February 24, 2026, the Company's Board has declared the first quarterly dividend in 2026 of approximately $25.1 million ($0.0371 per share) payable on April 7, 2026 to shareholders of record at the close of business on March 20, 2026.

SIGNIFICANT ACQUISITIONS

On June 23, 2024, the Company entered into the Amalgamation Agreement with BTG Oil & Gas and BTG Holding, a wholly-owned subsidiary of BTG Oil & Gas which held a 50% interest in Meren Coop (formerly known as Prime Oil & Gas Coöperatief U.A.), to reorganize and consolidate their respective 50:50 shareholdings in Meren Coop.

Pursuant to the Amalgamation Agreement, on March 19, 2025, BTG Holding amalgamated under Canadian corporate law with a subsidiary of the Company, and BTG Oil & Gas received an aggregate of 239,828,655 newly issued shares in the Company, representing approximately 35.5% of the outstanding share capital of the enlarged Company. Following completion of the transaction, the Company holds 100% of Meren Coop.

Concurrently with the Amalgamation Agreement, the Company and BTG Oil & Gas entered into an Investor Rights Agreement granting certain governance and consent rights to BTG Oil & Gas based on its shareholding in Meren. These include Board appointment rights (up to three non-executive directors, including the Chair, at 30% ownership, reducing proportionally at lower thresholds), committee representation, and customary information and registration rights. The agreement also imposes a two-year lockup and standstill on BTG Oil & Gas, provides the Company with a first-look right on BTG Oil & Gas' African upstream investment opportunities (subject to a 20% ownership threshold), and requires BTG Oil & Gas' consent for specified shareholder distributions, share issuances, and significant M&A transactions while its ownership remains above 20%. The Investor Rights Agreement will terminate if BTG Oil & Gas' ownership falls below 10%.

A Form 51-102F4 was filed in connection with the transaction on April 3, 2025, and is available on the Company's SEDAR+ profile at www.sedarplus.ca.

THE COMPANY'S BUSINESS

GENERAL

Meren's long-term plan is to deliver organic growth from its core assets to anchor sustainable total shareholder returns including a base dividend policy, whilst maintaining a strong balance sheet and minimum liquidity that provides for a resilient business through the cycle. This plan is supported by the Company's high netback production assets in Nigeria that are included in its interests in PMLs 2, 3 (previously part of OML 130) and PML 52 (previously part of OML 127). These PMLs provide the Company with a long-life cash flowing asset base, to support its business objectives over the long term, and together with PML 4, PPLs 261 and 2003 present development opportunities for supporting future production.

Meren, through a number of strategic transactions announced during 2024 and 2025, has secured its portfolio of funded organic growth opportunities. These include development and exploration assets in the Orange Basin, offshore Namibia and South Africa. It is also expected that the Company's growth opportunities in deepwater Nigeria, such as infill drilling on its producing fields and the appraisal and development of its discoveries will be funded from operating cash flow without any need for future equity injections.

The Company is in a strong and competitive position to deliver on its shareholder capital returns plans and to pursue inorganic growth opportunities focused on production assets.

The consolidation of all of the Meren Coop shareholdings in Meren, as well as doubling the Company's reserves and production, has also secured the Company a new strategic investor with substantial financial resources and an extensive network of relationships. The Company's management believe that BTG Oil & Gas, considering its strategic alignment for future investment in upstream oil and gas sector, will present the Company with a strong competitive advantage to pursue accretive business development opportunities in Africa and select other jurisdictions internationally.

SPECIALIZED SKILL AND KNOWLEDGE

The Company requires experienced professionals with specialized skills and knowledge to gather, interpret and process geological and geophysical data, design, drill and complete wells, and undertake numerous additional activities required to explore for, and produce, oil and gas. This includes experienced professionals with specialist data analytical skills, mathematical and computer skills, and a solid knowledge of engineering and geological information, such as reservoir simulation, seismic and electromagnetic methods, and rock properties to assist in determining which areas should be explored, appraised and developed, and which drilling methods will be most effective. In addition, the Company is dependent on senior management and directors of the Company in respect of corporate governance, environmental social governance and health and safety risks, and all matters pertaining to the Company. The Company has employed a strategy of attracting key members of management and directors, and contracting consultants and other service providers to supplement the skills and knowledge of its permanent staff in order to provide the specialized skills and knowledge to undertake its oil and gas operations and execute on its strategy efficiently and effectively. There is no assurance that the Company will continue to attract or retain all personnel necessary for the Company's business.

COMPETITIVE CONDITIONS

The petroleum industry is intensely competitive in all aspects, including the acquisition of oil and gas interests, the marketing of oil and gas, and acquiring or gaining access to necessary drilling and other equipment and supplies. Meren competes with numerous other companies in the search for and acquisition of such prospects and in attracting skilled personnel. Meren's competitors include oil companies that have greater financial resources, staff and facilities than those of Meren and its JV Parties. Meren's ability to increase its reserves in the future will depend on its ability to successfully explore, appraise and develop its current assets, as well as identify, select and acquire suitable producing assets. Meren must also respond in a cost-effective manner to external market factors that affect the distribution and marketing of oil and gas.

Meren's ability to bid successfully on and acquire additional oil and gas interests, to discover reserves, to participate in drilling opportunities, acquire producing assets and to identify and enter into commercial arrangements with customers will be dependent upon the development and maintenance of close working relationships with its future industry partners and joint operators and its ability to consummate transactions in a highly competitive environment. To achieve this, the Company strives to be cost efficient and remain competitive by maintaining a strong financial balance sheet.

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

Meren operates in a highly competitive environment, however, with a strong balance sheet, highly competent team, and the support of a new strategic shareholder the Company is positioned well to take advantage of potential opportunities in the near future.

CYCLICAL NATURE OF OPERATIONS

The Company's results and financial conditions are strongly linked to the prices of oil and gas. Such prices may be volatile as they are determined by certain factors, including weather, the demand for oil and gas, political changes and other global market factors.

ENVIRONMENTAL PROTECTION

Environmental legislation imposes certain restrictions, obligations, reporting requirements, disclosure and other potential duties on companies in the oil and gas industry. Activities related to the drilling, production, handling, transportation and disposal of oil, gas and petroleum by- products are subject to extensive regulation under international, national and local environmental laws, including those of the countries in which Meren currently operates. Environmental regulations may impose, among other things, restrictions, liabilities and obligations in connection with water management, air pollutants and other releases to the atmosphere, surface land, inland waterways and oceans, as well as the handling, storage, transportation, and disposal of waste.

Likewise, environmental regulations may impose restrictions on where and when oil and gas operations can occur, including additional permitting requirements and restrictions on operations in environmentally sensitive areas. These regulations may limit the potential routing of pipelines or location of production facilities.

Meren seeks to minimise the environmental impact of our oil and gas activities. We comply with applicable environmental laws and regulations of the countries in which the Company operates. Additionally, the Company maintains and updates its environment and emissions policy governing all staff and operated assets and manages its activities according to international industry good practice. Where Meren does not have operational control, it encourages, supports and works with its operating partners to the extent possible to act in a manner consistent with the Company's environmental policy and its performance expectations. Even where it is a non-operating shareholder, Meren seeks to ensure that activities are aligned with Company policies and performance expectations as far as practicable.

In addition to existing or prior activities on assets that are currently or were historically owned by the Company, the Company could potentially be liable for existing or new contamination on assets that it acquires in the future. The Company attempts to mitigate the risk of inheriting existing environmental liabilities on new assets by conducting appropriate due diligence on acquisition opportunities.

Environmental protection requirements have not, to date, had a significant effect on the Company's capital or operating expenditures, results of operations or competitive position. However, environmental regulations may become more stringent in the future and costs associated with compliance may increase. In addition, as the Company's exploration and operating activities evolve, new and more rigorously enforced environmental regulations may become relevant, which could impact those activities and the cost of compliance. Any penalties or other sanctions imposed on Meren (or its subsidiaries and JV Parties) for non-compliance with environmental regulations could have a materially adverse effect on Meren's business, prospects and results of operations, or could result in restrictions or cessation of operations and the imposition of fines and penalties.

More information regarding the Company's commitment to protecting the environment from the impact of its activities is available on the Company's website.

ENVIRONMENTAL AND SOCIAL POLICIES

In addition to the Company's current Environment & Emissions Policy, Meren maintains several other sustainability-related policies, including a Health & Safety Policy, a Community Relations & Human Rights Policy, and a Diversity, Equity and Inclusion Policy amongst others. These documents are publicly available on Meren's website.

To the extent possible given the Company's non-Operator role on assets, Meren endeavors to undertake activities in line with the International Finance Corporation's Performance Standards on Environmental and Social Sustainability and conduct regular independent assessments to evaluate compliance with IFC Performance Standards and other applicable standards. The independent assessment reports are publicly available on the Company's website.

Meren is committed to ensuring that its operational activities and, as far as it is able to influence them, those of its JV Parties and equity shareholdings, comply with applicable standards through its management systems and processes. Since 2020, the Company has had a Board-level committee, the Technical Committee (previously known as the Environmental, Social, Governance and Health and Safety Committee), responsible for overseeing environmental, social and health and safety matters. This committee provides the Board with regular updates on environmental and social performance and strategic initiatives, ensuring effective oversight of related risks. The Technical Committee meets at least once per quarter and comprises three members of the Board, all of whom are independent directors.

Meren's approach to sustainability matters aims to deliver value to its shareholders, while providing sustainable economic and social benefits to host communities and governments and minimizing its impact on the environment. Meren is committed to conducting its business responsibly, which it views as integral to its license to operate, enabling the Company to access and effectively manage existing and new business opportunities. Meren seeks to maintain its license to operate via regular engagement with key stakeholders. Where Meren operates, it interacts directly with government and community stakeholders in a spirit of transparency and good faith at all stages of Company activities. For non-operated assets, Meren engages with JV Parties and its equity shareholdings via operating and technical committee meetings and board meetings to guide activities and monitor adherence to corporate policies and good international practice.

The Company has contractual obligations and voluntary commitments to support community development initiatives under its licenses in Nigeria, South Africa and Equatorial Guinea. Through ongoing stakeholder engagement, it is the operators' responsibility to identify initiatives reflecting local priorities. In Nigeria, our partners provide support across key areas determined by the national government. In Equatorial Guinea, the Company has supported the renovation of a local school and the provision of community water wells on the mainland.

ECONOMIC DEPENDENCE

The Company is heavily dependent upon its counterparties, including host governments, JV Parties and other commercial third parties, under agreements including PSAs, joint venture agreements and farmout agreements that it has entered into for the exploration, appraisal, development and production of hydrocarbons. See 'Assets' on page 17 for more information on the Company's relationship with counterparties.

ASSETS

1. Nigeria: PML 52 and PPL 2003 (8.00% working interest at February 24, 2026) and PMLs 2, 3, 4 and PPL 261 (32% working interest at February 24, 2026)

The Company has interests in deepwater Nigeria production and development assets. The Nigerian assets include PML 52, which contains the producing Agbami field, as well as PPL 2003 and an interest in PMLs 2, 3 and 4 and PPL 261 which contain the producing Akpo and Egina fields as well as the Preowei and Egina South discoveries. Field production is in the deepwater area of the Niger Delta, the fields are produced through a subsea infrastructure of wells, manifolds and flowlines connected to three purpose built FPSOs. Water injection is used in all fields to maintain reservoir pressure and improve reservoir recoveries, and dedicated water injection wells are positioned to support the producing wells. The produced oil is sold to an international market directly from the offshore field location. The associated gas produced from the Egina and Akpo fields is sent via pipeline to shore and sold into the Nigerian liquified natural gas market. Gas from Agbami is currently reinjected into the reservoir to maintain reservoir pressure.

NIGERIA PRODUCTION SHARING AGREEMENTS OVERVIEW

Ownership structures for PML 52 and PPL 2003 and PMLs 2, 3, 4 and PPL 261 are summarized below in Figures 02a and 02b.

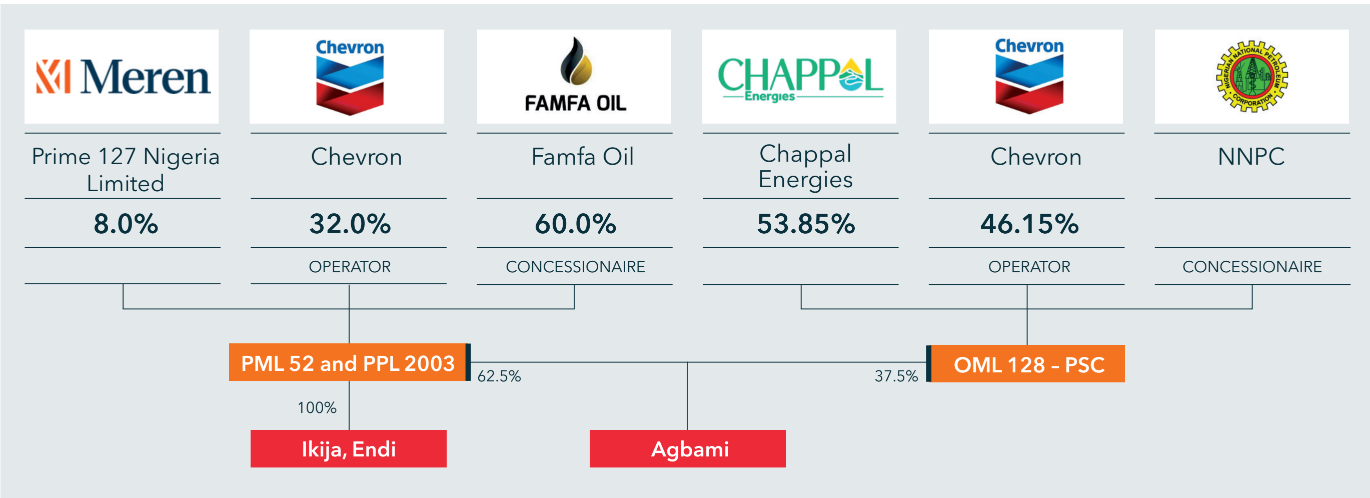


Figure 02a Tract participation PML 52 and PPL 2003 and OML 128

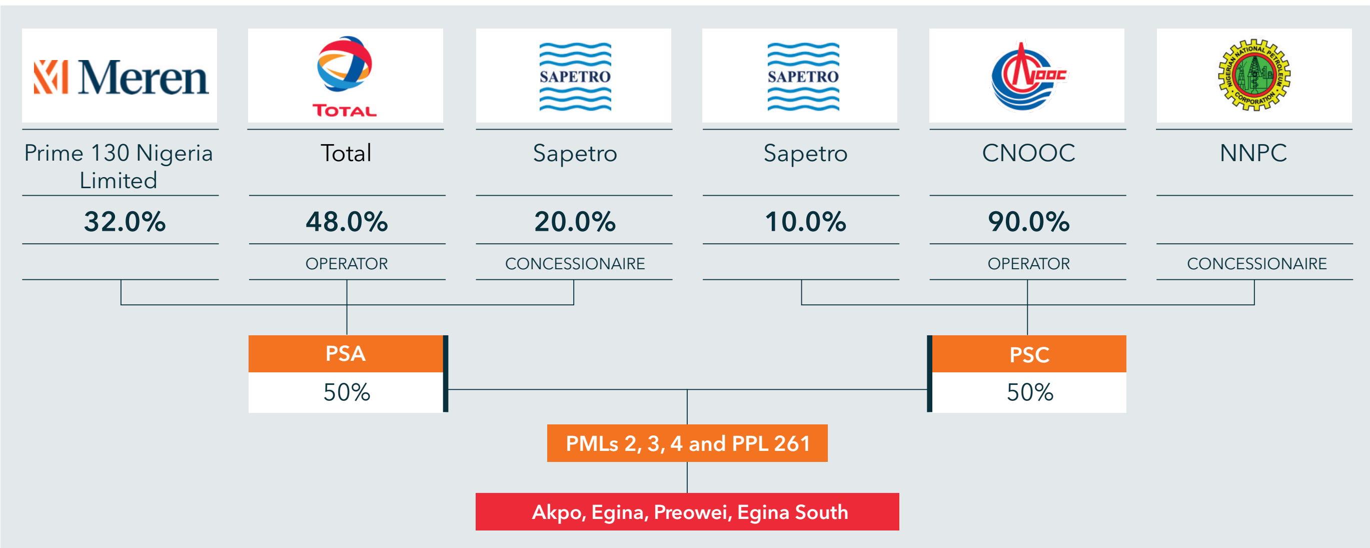


Figure 02b Tract participation PMLs 2, 3, 4 and PPL 261

ASSETS - CONTINUED

The Agbami field straddles PML 52 and OML 128. An Agbami unit agreement dated February 11, 2005 governs the rights and obligations of each block that constitutes the Agbami unit. The unit agreement makes provision for splitting of production from the unit between the two blocks in accordance with the agreed tract participation. The current PML 52 tract participation in the Agbami Unit, as at the date of this document, is 62.46%.

Meren also has an interest in a tract participation redetermination process for the Agbami field. The final technical procedure to adjust the tract participation of the PML 52 and OML 128 leases in the Agbami field was completed in October 2015. The process of implementing the new tract participation by the parties is ongoing and is subject to government approval.

On June 25, 2021, Meren 52, a subsidiary of Meren Coop, signed a securitization agreement with two of the unit parties, Equinor and Chevron, 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 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 Meren Coop sale and purchase agreement completed by Meren Holdings B.V. on January 14, 2020, a deferred payment of $118.0 million, subject to adjustment, may be due to the seller contingent upon the timing and 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, therefore does not trigger the payment of a contingent consideration under the sale and purchase agreement but, at the Company's discretion, could trigger discussions with the seller. The outcome of this process is uncertain. In 2021, the Company recorded $32.0 million as contingent consideration and increased this to $40.4 million as at December 31, 2024, and to $43.4 million in the year ended December 31, 2025.

OML 130 was renewed on May 28, 2023 extending the term of this Concession by 20 years to May 24, 2043 in accordance with the provisions of Nigeria's Petroleum Act and resulting in the award of three new petroleum mining leases and one petroleum prospecting license. These cover some of the areas previously covered by OML 130, with some of the areas also relinquished. These are PML 2 (Akpo field), PML 3 (Egina), PML 4 (Preowei) and PPL 261 (Egina South). PMLs 2, 3 and 4 and PPL 261 have operated under the terms of the new Petroleum Industry Act since June 1, 2023.

In February 2023, OML 127 was voluntarily converted under the new Petroleum Industry Act from March 1, 2023, which resulted in the new designation of PML 52 for the license area that contains part of the Agbami oil field. On October 29, 2024, PML 52 was renewed for a period of 20 years, effective November 24, 2024.

The following fiscal terms applied to both PML 52 and PMLs 2, 3, 4 and PPL 261 following their conversion to the PIA terms:

	Oil	**Gas**
Royalty	Deepwater production royalty of: 5% for production rates of less than 50,000 bopd; 7.5% for production rates of more than 50,000 bopd plus price royalty of: 0% for prices of less than $50/bbl, linear interpolation between $50/bbl and $100/bbl; 5% for prices at $100/bbl; linear interpolation between $100/bbl and $150/bbl; and 10% for prices of more than $150/bbl. Applicable to Agbami, Akpo and Egina fields 5% for exported Gas and 2.5% for Gas used inhouse (Nigeria)	5% for exported Gas and 2.5% for Gas used inhouse (Nigeria)
Education Tax	3%	3%
NDDC Levy	3%	-
Corporate Income Tax (CIT)	30%	30%
Capital Allowances	20% for 4 years; 19% per year thereafter	-
Ness Fee	0.12%	-
Host Community Development Funds	3% of previous year OPEX	3% of previous year OPEX
Naseni Levies	0.25% (of PBT)	0.25% (of PBT)
Police Force Levies	0.005% (of net profit)	0.005% (of net profit)

Notes

The PML 52 and PMLs 2, 3, 4 and PPL 261 PSAs have farm-in agreements with Famfa Oil and SAPETRO, respectively, as the concessionaires. Meren's current equity interest in the non-unitised part of PML 52 PSA is 8%, while its funding interest is 20%. Although privately held Nigerian company Famfa Oil is the official operator of the Block, the duties of the operator are delegated to a subsidiary of Chevron, which has an equity interest of 32% in PML 52 PSA and a funding interest of 80%. Famfa Oil holds the remaining equity interest of 60% in the license. However, cost oil and recovery oil remain 80% and 20% for Chevron and Meren, respectively, as Famfa Oil does not contribute to costs.

Meren's current equity interest in PMLs 2, 3, 4 and PPL 261 PSA is 32%, while its funding interest is 40% wherein it carries 40% of a 20% (i.e. 8%) share of the costs of privately held Nigerian company SAPETRO, the original owner of the Concession. Although SAPETRO is the official operator of the Block, the duties of the operator are delegated to TUPNI. TUPNI has an equity interest of 48% in PMLs 2, 3, 4 and PPL 261 PSA and a funding interest of 60%, wherein it carries 60% of a 20% (i.e. 12%) share of the costs of SAPETRO, which holds the remaining equity interest of 20% in the PMLs 2, 3, 4 and PPL 261 PSA.

2. Block 3B/4B South Africa (18.00%, working interest at February 24, 2026)

The Block 3B/4B was originally awarded on March 27, 2019, for an initial period of three years.

In July 2019, the Company through its wholly owned subsidiary, Meren SA Energy Corp. (formerly called Africa Oil SA Corp.), entered into a definitive farmout agreement with Azinam to acquire a 20% participating interest and operatorship in the Exploration Right for Block 3B/4B, offshore South Africa. The farmout was fully completed in February 2020 with Meren becoming the operator of the Block.

An application to extend the Block 3B/4B license and to move into the first extension period of two years was approved on October 27, 2022.

On July 11, 2023, the Company announced that it had entered into an agreement to increase its operated working interest in Block 3B/4B by 6.25% to 26.25%. The Company signed an agreement with Azinam, to acquire the 6.25% interest for a total cash consideration of $10.5 million. The first tranche of $2.5 million was paid during the three months period ended September 30, 2023. Completion occurred on January 19, 2024, increasing the Company's operated working interest to 26.25% and triggering payment by the Company of the second tranche of consideration for the transfer in an amount of $2.5 million. A third tranche of $4.0 million was paid to Eco upon the completion of a farmout deal to a third party on August 28, 2024, and a final tranche of $1.5 million will be payable upon spudding of the first exploration well on the Block.

On March 6, 2024, the Company announced the entry into of a strategic farm down agreement with TotalEnergies and QatarEnergy for the Block 3B/4B Exploration Right, located in South Africa. Following completion on August 28, 2024, the Company retained a 17.0% interest in Block 3B/4B and operatorship was transferred to TotalEnergies. The Company will receive, subject to achieving certain milestones as defined in the agreement, staged cash payments for a total amount of $10.0 million of which $3.3 million was received at closing of the transaction with the remaining balance to be received in two successive payments conditional upon achieving key operational and regulatory milestones. The Company will also receive a full carry of its retained share of all JV costs, up to a cap, that is repayable to TotalEnergies and QatarEnergy from production, and which is expected to be adequate to fund the Company's share of drilling for 1-2 wells on the license.

On July 26, 2024, the Company signed an agreement with Eco to acquire an additional 1.0% interest in Block 3B/4B from Azinam, in exchange for all common shares and warrants over common shares held by the Company in Eco. On completion of this transaction on January 10, 2025, the Company's interest in Block 3B/4B increased by 1.0% to 18.0% and the Company ceased to be a shareholder in Eco. Meren will benefit from the carry agreed between Eco, TotalEnergies and QatarEnergy for this incremental interest transferred from Eco to the Company.

On October 26, 2024, the Operator submitted an application to enter the second renewal period, the application is currently pending approval from the relevant authorities.

An Environmental Authorization for exploration activities (drilling of up to 5 exploration wells) was granted by the Department of Mineral Resources and Energy for the Republic of South Africa on September 16, 2024. Following that decision, the legislative notification and appeals process in South Africa was suspended pending a Supreme Court of Appeal judgment in respect of Block 5/6/7. The operator of Block 3B/4B has stated that the current plan is to drill the first exploration well as soon as the Environmental Authorization is confirmed and has identified Nayla, a prospect that lies in the northwest of the license area, as the potential drilling target.

3. Blocks EG-18 and EG-31 Republic of Equatorial Guinea (80% working interest at February 24, 2026)

In February 2023, the Company, through its wholly owned subsidiaries Africa Oil Alpha B.V and Africa Oil Beta B.V., entered into two new production sharing contracts for offshore Blocks EG-18 and EG-31 in the Republic of Equatorial Guinea. The Company holds an eighty per cent (80%) operated interest in each Block with the balance held by GEPetrol, the national oil company of Equatorial Guinea. GEPetrol has the option of acquiring an additional fifteen percent participating interest in each Block within 90 days of the approval of a field development plan on any potential discovery.

GEPetrol is carried during the exploration phase. Both Blocks have an initial 4-year term, divided into two 2-year sub periods. In December 2024, the Company was granted a 1-year extension to the first exploration sub period of both Blocks. In late 2025 the Company submitted requests for a further extension to the exploration license terms for both Blocks. 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.

In Block EG-31 the work commitments include purchasing 2D and 3D seismic data, reprocessing selected 3D seismic data, evaluated AVO response, preparing an inventory of and ranking exploration prospects, and providing recommendations for potential future drilling. From the existing data, the Company has already identified several potential gas-prone prospects in shallow water depths of less than 90 meters and close to existing infrastructure, including the offshore Alba gas field and the onshore Punta Europa Liquefied Natural Gas Terminal. On December 23, 2024, the Company received approval of the first amendment to the PSC to expand the Block boundary to include the full extent of the two main prospects on the Block.

In Block EG-18 the work commitments include purchasing 2D and 3D seismic data, reprocessing of selected 3D seismic data, conducting subsurface evaluation, AVO modelling, preparing estimates of prospective resource volumes and providing recommendations for potential future drilling. From the existing data set the Company has already identified three potentially large and highly prospective basin floor fan prospects of Cretaceous age that are similar to those within the Company's exploration portfolio in Namibia and South Africa and will continue to work these prospects as part of the initial exploration phase.

During the course of 2025, the Company has completed a number of data room exercises across the two Blocks and remains actively engaged in advancing potential partnership discussions. Following industry interest during the data room phase, the Company is now transitioning into the next stage of activity, focused on advancing discussions with prospective partners. In parallel, the Company continues to coordinate with government and representatives from GEPetrol to define the forward plan for both Blocks.

Should the Company successfully attract farm-in partner(s) on acceptable terms for these Blocks, subject to customary consents and approvals including governmental and regulatory permissions, the Company anticipates that newly formed JVs could be positioned to plan for appraisal and development as well as exploration drilling in late 2026 or 2027. While there can be no assurance of securing partners on acceptable terms, the Company remains encouraged by the level of industry interest and continues to advance partnership discussions with confidence.

4. Blocks 10BB, 13T and 10BA Kenya

On May 23, 2023, the Company submitted withdrawal notices to the remaining JV Party on Blocks 10BB, 13T and 10BA, to unconditionally and irrevocably withdraw from the entirety of the JOAs and PSCs for these Concessions. Government consent to the transfer was received on September 18, 2025, and the Company subsequently transferred all of its rights and future obligations on Blocks 10BB, 13T and 10BA to its remaining JV 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 December 31, 2025.

5. Equity Interest in Impact Oil & Gas Ltd. (39.46% equity interest at February 24, 2026)

Impact is a private UK oil and gas exploration company with assets located offshore Namibia and South Africa.

On February 24, 2022, Impact announced that the Venus-1X exploration well in Block 2913B, offshore Namibia, had discovered hydrocarbons. 4 subsequent wells, Venus-1X side track, Venus-1A, Venus-2A and Mangetti-1X have been drilled and tested to appraise the Venus discovery. The joint venture is continuing to progress the proposed development of the Venus field, with development studies ongoing. The Venus field is expected to be the first development in Block 2913B, producing 150 kbopd (gross field) of ~45° API oil, with final investment decision targeted for 2026.

On November 1, 2024, the Company announced the completion of a strategic farm down agreement between its investee company, Impact, and TotalEnergies. Following the closing of this deal, Impact retains a 9.5% interest in the Blocks that is fully carried for all joint venture costs, with no cap, through to first commercial production. Impact also received a cash reimbursement of approximately $99.0 million for its share of the past costs incurred on the Blocks net to the farmout interests.

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 the Carry Effective Date, until the Venus First Oil Date.

On and from the Venus 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.

The latest exploration drilling campaign on the Blocks was completed on April 25, 2025, with the drilling rig demobilized. Several further prospects are in the process of evaluation for drilling utilizing recently acquired 3D seismic data. The Environmental and Social Impact Assessment (ESIA) for the proposed Venus development has been completed and published, and the associated Environmental Clearance Certificate (ECC) application has been submitted to the relevant Namibian authorities. Completion of the ESIA represents a key regulatory milestone, further de-risking the project. FEED work is proceeding on the base-case concept of up to 40 subsea wells tied back to a single FPSO with a nameplate capacity of approximately 160,000 barrels per day of oil, with reinjection of associated gas offshore. Contractor bids have been received and are within expectation. The project schedule remains consistent with the current planning framework, with FID targeted for 2026 and first oil in 2030.

As at December 31, 2025, the Company held an indirect effective interest of approximately 3.8% in PEL 56 and in PEL 91 through its 39.46% shareholding in Impact.

6. Equity Interest in Africa Energy Corp. (11.56% equity interest at February 24, 2026)

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

In July 2024, Africa Energy announced that TotalEnergies EP South Africa B.V. had provided a notification to resign as operator of Block 11B/12B. In addition, TotalEnergies EP South Africa B.V., QatarEnergy International E&P LLC and CNR International (South Africa) Limited provided notice to the joint venture partners that they will withdraw from their 45%, 25% and 20% interest, respectively. Under the joint operating agreement, the withdrawing parties assigned their interests free of charge to each of the non-withdrawing partners in proportion to the interest of non-withdrawing partners. The withdrawal of the joint venture partners from Block 11B/12B is subject to all relevant regulatory approvals by South African authorities. Main Street 1549 took over as operator of Block 11B/12B on November 25, 2024, and is currently finalizing the handover of all important information from the previous operator.

On May 28, 2025, Africa Energy signed definitive agreements with Arostyle Investments (RF) (Proprietary) Limited ("Arostyle") to restructure their joint investment in Main Street 1549 Proprietary Ltd. ("Main Street 1549"), which holds the participating interest in Block 11B/12B. The restructuring will result in Africa Energy owning 100% of the common shares and 100% of the Class B shares of Main Street 1549. In addition, all loan claims between the Company and Arostyle will be settled in full. Finally, the 90% participating interest in Block 11B/12B to be assigned by the withdrawing parties will be assigned 65% to Main Street 1549 and 25% to Arostyle, resulting in Africa Energy (through Main Street 1549) holding a 75% participating interest in Block 11B/12B with Arostyle holding the remaining 25%. The definitive agreements are subject to all relevant regulatory approvals being obtained and remain subject to the fulfilment of certain conditions, including the finalization of the assignment agreements between Africa Energy, Arostyle and the withdrawing parties, which will require regulatory transfer approval under section 11 of the Mineral Petroleum Development Resources Act, 2002. Satisfaction of the conditions of the agreements is subject to a long stop date of September 30, 2026.

7. Other Material Contracts

Meren has contracts that are material to the Company and that were entered into between January 1, 2025, to the date of this AIF or that were entered into before that period but are still in effect, other than those entered into in the ordinary course of business, filed on the SEDAR website. The particulars of the Company's material agreements, as they relate to the Company's current operations, are provided below.

Agreement	Parties	Date of Agreement	Particulars
Investor Rights Agreement	Meren, BTG Oil & Gas	June 23, 2024	See 'General Development of the Business' for more information on this agreement.
Secured Revolving Reserve Based Lending Facility Agreement	Meren Coöperatief, Meren Nigeria 234 Limited, Meren Nigeria 52 Limited, The Standard Bank of South Africa Limited, Standard Chartered Bank, Africa Finance Corporation, ING Bank NV, Crédit Agricole Corporate Investment Bank, Societe Generale, London Branch, FirstRand Bank Limited (London Branch), and the other parties named therein as Original Lenders	July 18, 2014 (as amended from time to time and last amended on August 10, 2023)	Revolving facility agreement of up to US$1,050,000, with maturity on June 20, 2029 (6 year term), semi-annual scheduled repayment dates, interest periods of either one, three or six months and interest comprised of a reference rate based on the secured overnight financing rate - SOFR plus margin of between 4-4.5% per annum.
Deed of Amendment of the Sale and Purchase Agreement dated 31/10/2018, as amended on 31/10/2019	Meren, Petrobras International Braspetro B.V., Meren Holdings B.V., and Petróleo Brasileiro S.A. - Petrobras	January 11, 2020	Amendment documenting the extension of the longstop date of the Sale and Purchase Agreement.
Deed of Amendment of the Sale and Purchase Agreement dated 31/10/2018	Meren, Petrobras International Braspetro B.V., Meren Holdings B.V., Vitol Holding B.V., Delonex Energy Limited, and Petróleo Brasileiro S.A. - Petrobras	October 31, 2019	Amendment documenting the withdrawal of Delonex Energy Limited and Vitol Holding B.V. from the acquisition of 50% of Meren Coop.
Investors' Agreement	Meren, Impact, Deepkloof Limited, Helios Natural Resources 2 Limited	February 7, 2018	Investor agreement entitling Meren to certain decision-making controls over Impact
Sale and Purchase Agreement	Meren, Delonex Energy Limited, Vitol Holding B.V., Petrobras International Braspetro B.V., Meren Holdings B.V., and Petroleo Brasileiro S.A. – Petrobras	October 31, 2018	Sale and purchase agreement to acquire a 50% ownership interest in Meren Coop for an upfront cash payment of $519.4 million and a deferred payment of up to $118.0 million, subject to adjustment – see 'Assets' for more information on this agreement.

8. Disclosure of Reserves Data and Other Oil and Gas Information

For further information, please refer to Meren's Statement of Reserves Data and Other Oil and Gas Information for fiscal year ended December 31, 2025 (Form NI 51-101F1) and the Report of Management and Directors on Oil and Gas Disclosure (Form NI 51- 101F3), filed under the Company's profile on the SEDAR website at www.sedar.com, copies of which are attached hereto as Schedules A and C, respectively.

RISK FACTORS

The Company's operations are subject to various risks and uncertainties, including, but not limited to, those listed below. Where relevant, this section cross-references the Company's Management's Discussion and Analysis - December 31, 2025 ("MD&A") and the Notes to the Consolidated Financial Statements - December 31, 2025 for quantitative information, consistent with Canadian continuous-disclosure practice.

PRICES, MARKETS AND MARKETING OF CRUDE OIL AND NATURAL GAS

Crude oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, all of which are beyond the control of the Company. World prices for oil and gas have fluctuated widely in recent years. Any material decline in prices could have an adverse effect on the Company's business and prospects. The Company may be required by government authorities to limit production due to OPEC+ quotas from time to time. The conflicts in Ukraine and the Middle East have impacted global markets and may continue to result in increased volatility in financial markets and commodity prices. The Company does not have a direct exposure to operations in Ukraine or the Middle East.

The Company may undertake hedging activities when efficient to do so, however, hedging may not fully mitigate, in whole or in part, the risk and effect of lower commodity prices or may limit upside in rising markets. See MD&A - Risk Factors (Hedging) and Notes to the Financial Statements - Financial Instruments (Market Risk and Derivatives) for current derivative positions and sensitivities.

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

HEDGING

The Meren group enters into agreements to receive fixed prices on its oil and gas production to offset the risk of revenue reduction if commodity prices decline. However, if commodity prices increase beyond the levels set in such agreements, the Meren group will not benefit from such increases. See Notes to the Financial Statements - Financial Instruments (Market Risk - Commodity price risk and derivatives) for the treatment of fair-value through profit or loss derivatives and sensitivity analysis.

LIQUIDITY AND CASH FLOW

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

The Company could potentially issue debt or equity, extend its debt maturities and enter into farmout agreements to ensure it has sufficient available funds to meet current and foreseeable financial requirements.

The Company actively monitors its liquidity to ensure that its cash flows and working capital are adequate to support these financial obligations and the Company's capital programs. The Company will also adjust the pace of its activities to manage its liquidity position. Notwithstanding any mitigation efforts, the Company remains exposed to erosion of its balance sheet and revenues and may have difficulty in securing necessary funding, which may lead to insufficient liquidity. See MD&A - Liquidity and Capital Resources and Notes to the Financial Statements - Liquidity Risk for contractual maturities and facility information.

CREDIT FACILITIES

The Company is party to credit facilities. The terms of the facility contain covenants and restrictions on the ability of the Company to, among other things, incur or lend additional debt, pay dividends and make restricted payments, and encumber its assets. The failure of the Company to comply with the covenants contained in the facility or to repay or refinance the facility by its maturity date could result in an event of default, which could, through acceleration of debt, enforcement of security or otherwise, materially and adversely affect the operating results and financial condition of the Company. As disclosed in the Financial Statements, the Company's revolving reserve-based loan (RBL) amortizes quarterly to the lower of commitments and the borrowing base assessment and matures on June 20, 2029. See Notes to the Financial Statements - Liquidity Risk.

CREDIT RISK

Credit risk is the risk of loss if counterparties do not fulfil their contractual obligations. Most of the Company's credit exposure relates to amounts due from its JV Parties and receivables from crude oil sales. Sales are predominantly to investment-grade counterparties or supported by letters of credit/guarantees. A portion of the Company's cash is held by banks in foreign jurisdictions. See Notes to the Financial Statements - Credit Risk for concentrations and mitigation measures; and MD&A - Risk Factors (Credit Risk).

RISK FACTORS - CONTINUED

INTEREST RATE RISK

The Company has floating-rate borrowings that reference SOFR and therefore could be exposed to volatility in interest rates. See Notes to the Financial Statements - Market Risk (Interest Rate) for sensitivity analysis; and MD&A - Risk Factors (Interest Rate Risk).

SUBSTANTIAL CAPITAL REQUIREMENTS

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

To finance its future acquisition, exploration, development and operating costs, the Company may require financing from external sources, including from the issuance of new shares, issuance of debt or execution of working interest farmout agreements. There can be no assurance that such financing will be available to the Company or, if available, that it will be offered on terms acceptable to the Company.

If additional financing is raised through the issuance of equity or convertible debt securities, control of the Company may change and the interests of shareholders in the net assets of the Company may be diluted. If unable to secure financing on acceptable terms, the Company may have to cancel or postpone certain of its planned exploration and development activities which may ultimately lead to the Company's inability to fulfil the minimum work obligations under the terms of its various concessions. Availability of capital will also directly impact the Company's ability to take advantage of acquisition opportunities.

FINANCIAL STATEMENTS PREPARED ON A GOING CONCERN BASIS

Meren's financial statements have been prepared on a going concern basis under which an entity is considered to be able to realize its assets and satisfy its liabilities in the ordinary course of business. There can be no assurances that the Company will be successful in completing additional financings, achieving profitability or completing future transactions. See MD&A - Liquidity and Capital Resources and Notes to the Financial Statements - Basis of Preparation.

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

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

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

Risks Associated with Discovering Hydrocarbons

While the Company has historically made discoveries, there is no certainty that expenditures made on future exploration or development activities by Meren will result in discoveries of oil or gas in commercial quantities or that commercial quantities of oil and gas will be discovered, produced, or acquired by the Company. The portion of the Company's portfolio which include prospects & leads require additional data to fully define their potential and significant changes to the resource estimates will occur with the incorporation of additional data and information. There is no certainty that any discovered resources will be commercially viable to produce. There is no certainty that any portion of undiscovered resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

Risks Associated with Reserves and Resource Volume Estimates

In the event of a discovery, reservoir parameters, such as porosity, permeability, net hydrocarbon pay thickness, fluid composition and water saturation, may vary from those assumed by the Company's independent third-party resource evaluator affecting the volume of hydrocarbon estimated to be present. Other factors such as the reservoir pressure, density and viscosity of the oil, solution gas/oil ratio, permeability, the presence or absence of water drive and the specific mineralogy of the reservoir rock will affect the volume of oil that can be recovered. Drill stem tests, or well tests, are commonly based on flow periods of one to five days and build up periods of one to three days to aid in understanding reservoir performance. Well test results include uncertainty and are not necessarily indicative of long-term performance or of ultimate recovery.

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

Risks Associated with Production Guidance and Forecasting

Production guidance includes uncertainty around reservoir and well performance, reliability of production and process facilities, success of future drilling programs and execution of planned maintenance activities. Completion of future wells does not ensure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While structured maintenance plans, as well as close well, facility and operational supervision can contribute to maximizing production rates over time, production delays and declines from field operating conditions cannot be eliminated and may adversely affect production guidance, revenue and cash flow levels to varying degrees.

Risks Relating to Infrastructure

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

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

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

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

Risks Associated with the Availability of Equipment and Staff

Meren's oil and gas exploration and development activities are dependent on the availability of drilling and related equipment and qualified staff in the particular areas where such activities are or will be conducted. For any operated drilling or seismic activities, the Company would rely on the availability of leased drilling rigs or seismic equipment used for its exploration and development activities. Shortages of such equipment or staff may affect the availability of such equipment to the Company and may delay Meren's exploration and development activities and result in lower production.

INCREASED COSTS AND SUPPLY DISRUPTION

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

SHARED OWNERSHIP AND DEPENDENCY ON JV PARTIES

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

The Company and its JV Parties may also, from time to time, have different opinions on how to conduct certain operations or on what their respective rights and obligations are under a certain agreement. If a dispute were to arise with one or more JV Parties relating to a project, such dispute may have material adverse effect on the Company's or investee company's operations relating to such project.

RISKS RELATING TO CONCESSIONS, LICENSES AND CONTRACTS

Meren's operations are based on a relatively limited number of concession agreements, licenses and contracts. The rights and obligations under such concessions, licenses and contracts may be subject to interpretation and could also be affected by, among other things, matters outside the control of Meren. In case of a dispute, it cannot be certain that the view of the Company would prevail or that the Company otherwise could effectively enforce its rights which, in turn, could have significantly negative effects on Meren. Also, if the Company or any of its JV Parties were found to have failed to comply with their obligations or liabilities under a concession, license or contract, including record-keeping, budgeting, and time scheduling requirements, the Company's or JV Party's rights under such concession, license or contract may be terminated or otherwise relinquished in whole or in part. The Company cannot guarantee that requirements are adequately met by its JV Parties, which could bring an increased risk of impairment and reduced future cash flow.

GOVERNMENT REGULATIONS AND TAX RISK

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

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

Regulatory requirements affecting the oil and gas industry - including permitting rules, operational standards, local content requirements, and ongoing amendments to sector-specific legislation - may materially affect the Company's operations, timing of approvals, costs of compliance, fiscal terms, and continued access to concessions. These regulatory developments are incorporated within the Company's assessment of Government Regulations and Tax Risk.

INTERNATIONAL OPERATIONS

Meren participates in oil and gas projects located in emerging markets, primarily in Africa. Oil and gas exploration, development and production activities in these emerging markets are subject to significant political, economic, and other uncertainties that may adversely affect Meren's operations. The Company could be adversely affected by changes in applicable laws and policies in the countries where Meren has interests. Additional uncertainties include, but are not limited to, the risk of war, terrorism, expropriation, civil unrest, nationalization, renegotiation or nullification of existing or future concessions and contracts, the imposition of international sanctions, a change in crude oil or gas pricing policies, changes to taxation laws and policies, assessments and audits (including income tax) against the Company by regulatory authorities, difficulty or delays in obtaining necessary regulatory approvals, risks associated with potential future legal proceedings, and the imposition of currency controls.

These uncertainties, all of which are beyond Meren's control, could have a material adverse effect on Meren's business, prospects and results of operations. In addition, if legal disputes arise related to oil and gas concessions acquired by Meren, the Company could be subject to the jurisdiction of courts other than those of Canada. The Company's recourse may be very limited in the event of a breach by a government or government authority of an agreement governing a concession in which Meren acquires an interest. Meren may require licenses or permits from various governmental authorities to carry out future exploration, development and production activities. There can be no assurance that the Company will be able to obtain all necessary licenses and permits when required.

FOREIGN CURRENCY EXCHANGE RATE RISK

The Company is exposed to changes in foreign exchange rates as expenses in international subsidiaries, oil and gas expenditures, or financial instruments may fluctuate due to changes in rates. The Company's exposure is partially offset by sourcing capital projects and expenditures in US dollars. The Company had no forward exchange contracts in place as at December 31, 2025. See Notes to the Financial Statements - Market Risk (Foreign Currency) for qualitative mitigation disclosures.

DECOMMISSIONING

The Company is responsible for compliance with all applicable laws, regulations and contractual requirements regarding the decommissioning, abandonment, and reclamation of the Company's assets at the end of their economic life. See Notes to the Financial Statements - Provisions (IAS 37) for assumptions and, where provided, sensitivity analysis.

HEALTH & SAFETY RISKS

The oil and gas industry involves inherent health and safety risks, including harsh and remote environments, heavy equipment, hazardous materials, high temperatures and high-pressure equipment. Meren is committed to operating in a safe and responsible manner, in alignment with international industry best practice and the laws and regulations of the countries where we operate. The Company maintains a Health & Safety policy, which is reviewed annually and outlines its commitments, including the governance processes and management systems used to ensure compliance with this policy. Where Meren does not operate, the Company engages with its JV Parties and operators on health and safety practices and monitors performance via quarterly reporting.

These efforts can help to reduce but not fully eliminate the risks associated with oil and gas activities, including fire, explosion, blowouts, gas releases, ruptures and personnel accidents. Should they occur, each of these hazards could result in substantial personal injury to employees, contractors or other bystanders, as well as damage to oil and gas wells, production facilities and other property. In this case, the Company could be exposed to fines, penalties and other legal liabilities, as well as reputational damage, including loss of license to operate, and such damages may not be fully insurable.

CLIMATE RISKS

Market Risks

Changing consumer preferences for low carbon sources of energy, transport and products and services may erode demand for oil and gas as alternatives continue to mature and gain scale. Although recent political developments in the United States and a recalibration of climate priorities in parts of the European Union have contributed to a more fragmented global policy landscape, market forces, capital allocation trends, and technological developments continue to drive the adoption of lower carbon solutions. As a result, reduced long-term demand for oil and gas may result in stranded reserves or resources and could adversely affect the Company's valuation and share price.

In addition to limiting the Company's ability to sell into certain markets, evolving demand patterns and divergent regional policy approaches could exert downward pressure on commodity prices over the medium and long term. At the same time, unbalanced investment between traditional and emerging energy technologies, combined with heightened uncertainty regarding demand trajectories, may contribute to increased short-term commodity price volatility. Supply chains may also experience disruption, as suppliers adjust their strategies, capital allocation and product offerings in response to both market-driven and region-specific transition dynamics, potentially increasing costs for certain goods and services.

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

Litigation Risks

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

Regulatory Risks

Since the Paris Agreement was signed in 2015, countries have steadily enacted policies to enable the transition to a low carbon future and meet their Nationally Determined Contributions (NDCs). This includes the governments of countries where Meren conducts business. These policies may directly or indirectly increase the cost of doing business in these countries or potentially restrict the Company's ability to operate. Meren regularly monitors the evolving regulatory landscape, both globally and in the Company's countries of operation, to anticipate the impact of new climate- related measures and ensure ongoing compliance.

Additionally, the Company has developed an emissions management strategy which is focused on the reduction of emissions from a baseline level over the lifetime of a producing asset. This strategy is intended to help the Company remain aligned with evolving regulatory requirements and mitigate potential adverse impacts.

Reputational Risk

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

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

Physical Risks

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

See MD&A - Risk Factors (Climate Risks) and Notes to the Financial Statements (e.g., Provisions/Impairment) where relevant for financial statement effects.

OTHER ENVIRONMENTAL RISKS

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

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

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

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

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

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

INSURANCE

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

INVESTMENTS IN ASSOCIATES AND INVESTMENTS IN JOINT VENTURES

The Company has invested in other frontier oil and gas exploration companies that face similar risks and uncertainties, which could have a material adverse effect on their businesses, prospects and results of operations. Such risks include, without limitation, equity risk, liquidity risk, commodity price risk, credit risk, currency risk, foreign investment risk, and changes in environmental regulations, economic, political or market conditions, or the regulatory environment in the countries in which they operate. The associates or joint ventures are entities in which the Company has some influence, including through its representation on their boards, but given its equal or minority interest, no or limited control over their decisions, including, without limitation, financial and operational policies, the Company has no or limited control over outcomes, performance and governance.

The Company's access to information is subject to the contractual provisions of shareholder agreements. The Company is reliant on the information provided by investments and may not have the ability to independently verify such information. The Company's investments are not diversified over different types of investments and industries, rather, they are concentrated in one type of investment. If an associated company or jointly controlled entity in which the Company has invested fails, liquidates, or becomes bankrupt, the Company could face the potential risk of loss of some, or all, of its investments, and may be unable to recover any of its investments.

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

LEGAL SYSTEM, LITIGATION AND REMEDIES

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

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

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

BRIBERY, CORRUPTION AND FRAUD

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

SIGNIFICANT SHAREHOLDER

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

COUNTERPARTY INTEGRITY

The Company relies on third parties, including suppliers, contractors, and business partners, to support its operations and strategic objectives. Failure to conduct adequate due diligence on these counterparties could expose the Company to significant legal, financial, and reputational risks. These risks include association with entities that are subject to sanctions, involved in law enforcement or regulatory actions, politically exposed persons (PEPs), or linked to bribery, corruption, fraud, or other criminal activities. Additionally, negative media coverage of counterparties may adversely affect the Company's reputation. While the Company maintains processes to assess and monitor counterparties, these measures may not fully eliminate the risk of misconduct or regulatory breaches by third parties, which could result in penalties, operational disruption, or damage to stakeholder trust.

CYBERSECURITY

The Company has become increasingly dependent upon the availability, capacity, reliability and security of its information technology (IT) infrastructure, and its ability to expand and continually update this infrastructure, to conduct daily operations. It depends on various IT systems to estimate resources and reserve quantities, process and record financial and operating data, analyse seismic and drilling information, and communicate with employees and third-parties. The Company's IT systems are increasingly integrated in terms of geography, number of systems, and key resources supporting the delivery of IT systems. The performance of key suppliers is critical to ensure appropriate delivery of key services. Any failure to manage, expand and update the IT infrastructure, any failure in the extension or operation of this infrastructure, or any failure by key resources or service providers in the performance of their services could materially and adversely affect the Company's business, financial condition and results of operations.

The ability of the IT function to support the Company's business in the event of a disaster such as fire, flood or loss of any of the office locations and the ability to recover key systems from unexpected interruptions cannot be fully tested. There is a risk that, if such an event occurs, the Company's continuity plan may not be adequate to immediately address all repercussions of the disaster. In the event of a disaster affecting a data centre or key office location, key systems may be unavailable for several days, leading to inability to perform some business processes in a timely manner.

The Company applies technical and process controls and security measures in line with industry-accepted standards to protect information, assets and systems. However, these controls and measures on which the Company relies may not be adequate due to the increasing volume, sophistication and rapidly evolving nature of cyber threats. The Company's information technology and infrastructure, including process control systems, may be vulnerable to attached by malicious persons or entities or breached due to employee error, malfeasance or other disruptions, including natural disasters and acts of war. There is no assurance that the Company will not suffer losses associated with cyber-security attacks, breaches, access, disclosure or loss of information in the future and may be required to expend significant additional resources to investigate, mitigate and remediate any potential vulnerabilities or could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties, disruptions to the Company's operations, decreased performance and production, increased costs and damage to the Company's reputation or other negative consequences to the Company, which could have a material adverse effect on the Company's business, financial condition and results of operations.

HUMAN RIGHTS

The Company is committed to operating in a socially responsible and transparent manner and values the human rights of its workers, contractors and external stakeholders, including the local communities where it operates. The Company complies with the applicable laws and regulations of the countries in which it operates, including local labor regulations, and additionally manages its activities according to international human rights standards as defined by the United Nations Guiding Principles on Business and Human Rights, the Universal Declaration of Human Rights and the International Labour Organization Fundamental Conventions, amongst others. Where national law and international human rights standards differ, the Company will follow the most stringent standard, and where they are in conflict, will adhere to national law, while seeking ways to respect international human rights to the greatest extent possible.

The Company maintains a Human Rights Policy outlining its human rights commitments and the measures taken to ensure human rights are respected and upheld across all business activities, whether operated or non-operated. These measures include preventative due diligence of contractors and business development opportunities, environmental and social impact assessments ahead of any new development and a grievance mechanism to encourage prompt reporting of any suspected violation.

Despite these measures, Meren may inadvertently find itself complicit in human rights violations through the actions of contractors or suppliers, or government managed processes, such as security or resettlement. In this case, the Company could be exposed to immeasurable reputational damage and legal action, including loss of license to operate.

M&A STRATEGY

The Company's strategy for growth includes mergers and acquisitions. The Company competes with a substantial number of other E&P companies in the search for M&A and potential farmout and farmin opportunities. The Company's ability to successfully execute this strategy is dependent upon its ability to identify, select, and evaluate suitable opportunities within limited time frames, and to close transactions in a highly competitive environment. The availability of suitable M&A targets and potential farmout and farmin opportunities may be limited, or the acquisition terms may not be agreed, particularly in a volatile oil and gas market. The Company's competitors include oil and gas companies that may have substantially greater financial resources than the Company. Meren's operating cash flow may not be sufficient to meet the expenditure required for the Company to complete its M&A opportunities. The Company may require additional financing to complete such transactions, and this may not be available or offered on acceptable terms, further explained in the Liquidity and Cash Flow risk factor.

RELIANCE ON KEY PERSONNEL

The loss of the services of key personnel could have a material adverse effect on the Company's business, prospects, and results of operations. Meren has not obtained key person insurance in respect of the lives of any key personnel. In addition, there is competition for qualified personnel in the oil and gas industry and there can be no assurance that the Company will be able to attract and retain the skilled personnel necessary for operation and development of its business. Success of the Company is largely dependent upon the performance of its management and key employees. To mitigate this risk, the Company has in place long term equity measures, notice provisions and also planned succession where possible.

UNCERTAINTY OF TITLE

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

CURRENT GLOBAL FINANCIAL CONDITIONS

Global financial conditions have always been subject to volatility. These factors may impact the ability of the Company to obtain equity or debt financing in the future and, if obtained, on terms favorable to the Company. Increased levels of volatility and market turmoil can adversely impact the Company's operations and the value, and the price of the common shares could be adversely affected. Political developments and policy changes in the United States, including shifts in trade relations, sanctions enforcement, and fiscal or monetary policy, may also create uncertainty and have adverse impacts on the Company, its operations and its access to financing.

SHAREHOLDER CAPITAL RETURNS

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

POSSIBLE FAILURE TO REALIZE ANTICIPATED BENEFITS OF THE CONSOLIDATION OF MEREN COOP

The Company anticipates that the consolidation of Meren Coop in 2025 will strengthen its position in the oil and gas industry and create the opportunity to realize certain benefits as described in this Annual Information Form. Achieving the anticipated benefits of the consolidation depends on the Company's ability to realize anticipated growth opportunities. There can be no assurance, however, that the anticipated benefits of the consolidation will materialize. It is possible that the risks and uncertainties described in this Annual Information Form will arise and become material to such an extent that some or all of the anticipated benefits of the consolidation of Meren Coop will never materialize or will be nullified.

SELLING OFF OF SHARES

The market price and trading volumes for the Company's common shares may be volatile, and subject to fluctuations. To the extent that any issued and outstanding common shares of the Company are sold into the market, there may be an oversupply of common shares and an undersupply of purchasers. If this occurs the market price for the common shares of the Company may decline significantly and investors may be unable to sell their common shares at a profit, or at all. During periods of low trading volumes, the share price could move materially and unexpectedly even if there are no material news to be reported.

ACTIVIST SHAREHOLDERS

Publicly traded companies could be subjected to demands from activist shareholders advocating for changes to corporate governance practices and corporate actions. There can be no assurances that activist shareholders will not publicly advocate for the Company to make certain governance changes or engage in certain corporate actions. Responding to challenges from activist shareholders could be costly and time consuming and could divert the attention and resources of the Company's management and Board, which could have an adverse effect on the Company's business and results of operations. Activist shareholders may attempt to acquire control of the Company to implement changes. If activist shareholders with differing objectives are elected to the Board, this could adversely affect the Company's business and future operations. Additionally, shareholder activism could create uncertainty about the Company's future strategic direction, resulting in loss of future business opportunities, which could adversely affect the Company's business, future operations, profitability, and Meren's ability to attract and retain qualified personnel.

CONFLICTS OF INTEREST

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

GLOBAL CONFLICTS

Global conflicts, including those in Ukraine and the Middle East have impacted global markets and may continue to result in increased volatility in financial markets, commodity prices and disruptions in supply chains. The Company does not have a direct exposure to operations in Ukraine or the Middle East and does not have any business relationships with any sanctioned entities or people. The Company will continue to review all its engagements with new stakeholders to ensure this remains the case.

GLOBAL HEALTH EMERGENCY

The Company's business, financial condition and results of operations could be materially and adversely affected by epidemics, pandemics or other public health crises. The degree to which a public health crisis impacts our results is uncertain and cannot be predicted, including, but not limited to, the duration and spread of the outbreak, its severity, the actions to contain the virus and its variants or treat their impact, the efficiency of vaccination campaigns against the virus and all its variants, and how quickly and to what extent the worldwide economic activity can recover to pre-crisis levels.

DIVIDENDS AND DISTRIBUTIONS

DIVIDEND AND DISTRIBUTION POLICY

In 2025, the Board implemented a new shareholder returns program pursuant to which the Company may, if and when determined appropriate by the Board and subject to a variety of factors and conditions existing from time to time, pay an annual base dividend of $100.0 million payable on a quarterly basis, supplemented by additional distributions, through dividends and/or share buybacks, equivalent to up to 50% of free cash flow generated after payment of the base dividend. In addition, in each of 2023 and 2024, the Company declared dividends on a semi-annual schedule, with each dividend set at $0.025 per share.

It is intended that dividends declared and paid by Meren will qualify as "eligible dividends" for the purposes of the Income Tax Act (Canada) (and any similar applicable provincial legislation). No assurances can be given that all dividends will qualify as "eligible dividends" and the designation of dividends as "eligible dividends" will be subject to the discretion of the Board.

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.

DIVIDEND HISTORY

During the years ended December 31, 2023, 2024 and 2025, the Company paid the following cash dividends to shareholders:

$ per share	Q1	Q2	Q3	Q4	Year
2025	0.0371	0.0371	0.0371	0.0371	0.148
2024 [1]	0.025	-	0.025	-	0.050
2023 [1]	0.025	-	0.025	-	0.050

1. In each of 2023 and 2024, the Company declared dividends on a semi-annual basis, with each dividend set at $0.025 per share.

NORMAL COURSE ISSUER BID ("NCIB")

On September 27, 2022, the Company launched a NCIB share buyback program pursuant to which the Company was permitted to purchase for cancellation up to 40,482,356 of its common shares. This NCIB commenced on September 27, 2022 and terminated on September 26, 2023. The Company purchased and cancelled 20,512,373 of its common shares under this bid.

On December 6, 2023, the Company launched a NCIB share buyback program pursuant to which the Company was permitted to purchase for cancellation up to 38,654,702 of its common shares. This NCIB commenced on December 6, 2023 and terminated on December 5, 2024. The Company purchased and cancelled 23,987,632 of its common shares under this bid.

On December 4, 2024, the Company renewed its NCIB share buyback program, pursuant to which the Company was authorized to purchase for cancellation up to 18,362,364 common shares of the Company.

This NCIB commenced on December 6, 2024 and terminated on December 5, 2025. The Company purchased and cancelled 8,438,153 of its common shares under this bid.

On December 4, 2025, the Company renewed its NCIB share buyback program. Pursuant to the NCIB, Meren is authorized to repurchase, through the facilities of the TSX, Nasdaq Stockholm and/or alternative Canadian trading systems, up to 21,636,913 common shares of the Company for a total maximum amount of CAD 35 million, which represents 5% of its "public float" of 432,738,277 common shares as at November 24, 2025, over a period of up to twelve months, commencing on 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. As at the date of this AIF, the Company has not purchased any common shares under the bid.

MEREN'S CAPITAL STRUCTURE

THE COMPANY'S SHARES

Meren is authorized to issue an unlimited number of the Company's common shares without par value. As of December 31, 2025, the Company had 675,909,193 common shares issued and outstanding. As of the date of this AIF, the Company had 675,909,193 common shares issued and outstanding as fully paid and non-assessable.

Each shareholder is entitled to receive notice of and to attend all meetings of Meren's shareholders. In addition, each share entitles the holder to one vote, either in person or by proxy, on any resolution to be passed at such shareholders' meeting. The holders of common shares are also entitled to dividends if, as and when declared by the Board. Upon the liquidation, dissolution or winding up of the Company, the holders of the common shares are entitled to receive the remaining assets of the Company available for distribution to the shareholders.

RESERVES BASED LENDING FACILITY

Following the amalgamation, Meren has a Reserves Based Lending Facility ("RBL"). The total amount that can be drawn under the RBL is limited to the Borrowing Base Amount ("BBA"), which is subject to redeterminations on March 31 and September 30 of each year, limited by aggregate commitments. As of December 31, 2025, the BBA was $468.4 million, which will amortize as the RBL moves towards final maturity. On October 28, 2025, the Company voluntarily cancelled $100.0 million of its RBL commitments resulting in a remaining total commitment of $700.0 million.

For further information regarding the RBL, see the Company's annual audited financial statements and related management's discussion and analysis for the year ended December 31, 2025. See also "Risk Factors – Credit Facilities".

MARKET FOR SECURITIES

PRICE RANGE AND TRADING VOLUME

The Company's primary listing of its common shares is on the TSX and is traded under stock symbol "MER". The following table sets out the price ranges and volume traded of Meren's common shares on the TSX, for the year ended December 31, 2025:

Month	High (CAD$)	Low (CAD$)	Volume
January	2.14	1.87	19,763,903
February	1.98	1.84	35,046,423
March	2.18	1.79	28,732,934
April	2.10	1.59	29,108,563
May	1.98	1.76	15,733,476
June	1.88	1.66	40,524,555
July	1.82	1.61	86,309,106
August	1.86	1.65	29,115,415
September	1.94	1.72	22,520,543
October	1.91	1.68	22,929,144
November	1.87	1.67	36,522,380
December	1.86	1.69	27,596,911

The Company is also listed on Nasdaq Stockholm and is traded under the stock symbol "MER". The following table sets out the price ranges and volume traded of Meren's common shares on Nasdaq Stockholm, for the year ended December 31, 2025:

Month	High (SEK)	Low (SEK)	Volume
January	16.8	14.38	15,087,076
February	15.11	13.86	21,787,944
March	15.40	12.54	21,380,950
April	14.59	11.23	17,420,587
May	14.20	12.46	25,137,800
June	13.26	11.78	21,438,066
July	12.91	11.50	23,518,221
August	12.81	11.50	16,848,492
September	13.24	11.74	17,669,795
October	12.90	11.37	16,738,894
November	12.60	11.40	15,418,034
December	12.65	11.51	17,140,196

PRIOR SALES

Stock Options

The Company ceased awarding stock options in 2021 and did not issue any stock options between 2022 and 2025.

Share Units

The table below summarizes the share units that were issued by the Company in 2025 and remain outstanding at the end of the reporting period:

Date of Issuance	RSUs(1)	PSUs(2)
January 15, 2025	140,400	2,637,000
March 20, 2025	338,000	1,005,300
July 1, 2025	53,900	395,900

1. During 2025 an aggregate additional 61,265 RSUs were issued as dividend credits.
2. During 2025 an aggregate additional 465,592 PSUs were issued as dividend credits.

DIRECTORS AND OFFICERS

THE DIRECTORS

The table below states the name, province or state and country of residence of each current director of Meren, their respective principal occupations during the five preceding years, and the period during which each director has served as a director of the Company.

Director Name, Province/State, Country	Principal Occupation Past Five Years	Director Since (1)
Huw Jenkins (2) (9) London, United Kingdom	Director of BTG Pactual.	2025
Michael Ebsary (3) (4) (9) Geneva, Switzerland	Director of ShaMaran Petroleum Corp. since 2019; Advisory Board Chairman, Vesselnet from 2021 to 2024; independent consultant Ebsary Consulting SA since 2017.	2024
Edwyn Neves (5)(6) Sao Paulo, Brazil	Managing Partner of BTG Pactual.	2025
Pascal Nicodeme (7) London, United Kingdom	Chief Financial Officer of Meren Energy Inc. from 2019 to 2025.	2025
Richard Norris (10) Montreal, Canada	Director of Maha Capital AB. since 2022, Partner Pandreco Energy Advisors Inc.	2025
Oliver Quinn London, United Kingdom	President & CEO, Meren Energy Inc. since February 2026 (formerly Chief Commercial & Operating Officer since September 2025 and Chief Commercial Officer from November 2023 to September 2025); SVP - Corporate Development and SVP - Corporate Strategy of Kosmos from 2019 to 2023.	2026
Cheryl Sandercock (5)(11) Calgary, Canada	Managing Director & Co-Head, Energy Acquisitions and Divestitures, BMO Capital Markets from 2016 to 2024.	2025
Ahonsi Unuigbe (11) Lagos, Nigeria	Founder, CEO and Director of Petralon Energy; Chairman of the Board Nigerian Exchange Limited.	2025
Kimberley Wood (7)(8) London, United Kingdom	General Counsel and Company Secretary at Storegga since September 2023; Director of Gulf Keystone Petroleum (until June 2024); Director of Valeura Energy (until September 2023); and Senior Consultant at Norton Rose Fulbright LLP 2018 to 2023.	2018

1. The term of office of each of the directors will expire at the 2026 annual general meeting of the Company's shareholders.
2. Chair of the Board
3. Lead Independent Director
4. Audit Committee Chair
5. Audit Committee Member
6. Compensation Committee Chair
7. Compensation Committee Member
8. Corporate Governance and Nominating Committee Chair
9. Corporate Governance and Nominating Committee Member
10. Technical Committee Chair
11. Technical Committee Member

THE EXECUTIVE OFFICERS

The table below states the name, province or state and country of residence of each of the current executive officers of Meren, their respective positions and offices held with the Company, and their principal occupations during the five preceding years.

Dr. Oliver Quinn, the Company's President and Chief Executive Officer is discussed above under 'The Directors'.

Executive Officer's Name, Province/State, Country	**Position with Meren and Principal Occupation** Past Five Years
Aldo Perracini London, United Kingdom	Chief Financial Officer since March 2025; Chief Financial Officer and then Chief Executive Officer of Prime Oil & Gas from 2019 to 2025.
Joanna Kay London, United Kingdom	Chief Legal Officer and Corporate Secretary since December 2023; Associate General Counsel and Company Secretary with BW Energy from March 2020 to October 2023; Counsel, Energy & Infrastructure with Orrick, Herrington & Sutcliffe from February 2016 to March 2020.
Thomas Haffenden London, United Kingdom	Chief Human Resources Officer since August 2025; HR Director at Northrop Grumman from November 2022 to June 2025; HR Director at CGN UK from February 2017 to October 2022.

SECURITY HOLDINGS

As of the date of this AIF, the directors and executive officers of the Company, as a group, beneficially own, or control or direct, directly or indirectly 2,865,660 common shares, representing approximately 0.42% of the issued and outstanding common shares of the Company. This security holding information was obtained from publicly disclosed information and has not been independently verified by the Company.

CEASE TRADE ORDERS, BANKRUPTCIES, PENALTIES OR SANCTIONS

Corporate

No director or executive officer of the Company is, as at the date of the AIF, or has within the ten (10) years before the date of the AIF, been a director, chief executive officer, or chief financial officer of any company (including Meren) that:

i. was the subject of a cease trade or an order similar to a cease trade order, or an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than thirty (30) consecutive days that was issued: (A) while that individual was acting in such capacity; or (B) after that individual ceased to act in that capacity and which resulted from an event that occurred while that person was acting in such capacity; or

ii. became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or comprise with creditors or had a receiver, receiver- manager or trustee appointed to hold its assets: (A) while that person was acting in such capacity; or (B) within a year of that person ceasing to act in that capacity.

Personal

a. No director or executive officer of the Company has, within the ten (10) years before the date of the AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold that person's assets.

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

CONFLICTS OF INTEREST

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

AUDIT COMMITTEE

OVERVIEW

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

AUDIT COMMITTEE MEMBERS

The Audit Committee is comprised of Mr. Michael Ebsary (Chair), Mr. Edwyn Neves, and Ms. Cheryl Sandercock. All present members are considered 'independent' within the meaning of NI 52-110 because they do not have any direct or indirect 'material relationship' with the Company. A material relationship is a relationship, which could, in the view of the Company's Board, reasonably interfere with the exercise of a member's independent judgment.

Each current member is also considered 'financially literate' within the meaning of NI 52-110. They have extensive experience with financial statements, accounting issues, understanding internal controls and procedures for financial reporting and other related matters relating to public resource-based companies. The education and experience of each Audit Committee member that is relevant to the performance of his responsibilities as a member of the Audit Committee are as follows:

Michael Ebsary (Chair)

Mr. Ebsary was the Chief Executive Officer, and a director of Oryx Petroleum Corporation Limited from 2010 until 2016. He served as the Chief Financial Officer of Addax Petroleum Corporation, an international oil and gas exploration and production company, for eleven years between 1998 and 2009. These two companies had operations throughout Africa and Kurdistan. He previously held various positions in project finance and treasury with oil companies Elf Aquitaine and Occidental Petroleum, both in France and the United Kingdom. He began his working life in multinational banking institutions in Canada and the United Kingdom, after graduating with an MBA from Queen's University in Canada.

Edwyn Neves

Mr. Neves is a managing director partner at BTG Pactual where he is responsible for the Capital Solutions Group, in addition to managing proprietary equity investments in Estapar, a publicly listed company in Brazil and the largest parking company of Latin America. Mr. Neves is the Chairman of Estapar (parking company) and a board member of Via Appia (highways operator). Over the last 16 years at BTG Pactual, Mr. Neves has led investments of more than US$6 billion in over 100 transactions across several different sectors and instrument types (common and preferred equity and senior/junior/mezzanine debt). Mr. Neves holds a bachelor's degree in Business Administration from Fundação Getulio Vargas.

Cheryl Sandercock

Ms. Sandercock was the Co-Head of Acquisitions and Divestitures in the Energy Advisory Investment Banking practice of BMO Capital Markets, a leading provider of investment banking services in the resource sectors (energy, mining and energy transition). She has advised on over US$70 billion of transactions, including acquisitions, divestitures, mergers, strategic alternatives, farmins, royalties, equity raises, joint ventures, defense preparedness and hostile defense for public and private companies of all sizes, NOCs, and private equity investors. Ms. Sandercock's prior experience includes another large Canadian multi-national bank, independent reserve and resource assessments with two recognized independent qualified reserves evaluators firms, and technical roles in drilling & completions, reservoir, production, development and gas storage engineering as well as field operations for an oil & gas exploration and production company. Ms. Sandercock attended the Schulich School of Engineering at the University of Calgary, Canada, earning a B.Sc. in Chemical and Petroleum Engineering. She is a professional engineer registered with the Association of Professional Engineers and Geoscientists of Alberta (APEGA) and holds the ICD.D designation from the Institute of Corporate Directors in Canada.

AUDIT COMMITTEE OVERSIGHT

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

RELIANCE ON CERTAIN EXEMPTIONS

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

PRE-APPROVAL POLICIES AND PROCEDURES

The Audit Committee has adopted specific policies and procedures for the engagement of non-audit services as described in the Audit Committee Charter attached as Schedule "D" to this AIF.

EXTERNAL AUDITOR SERVICE FEES (BY CATEGORY)

The following table discloses the fees billed to the Company by its external auditor during the last two fiscal years:

Financial Year Ending	Audit Fees (CAD$) (1)	Audit Related Fees (CAD$) (2)	Tax Fees (CAD$) (3)	All Other Fees (CAD$) (4)
December 31, 2025	832,255	569,248	222,548	4,745
December 31, 2024	325,820	313,282	185,398	3,964 [5]

1. Aggregate billed for audit services.
2. Aggregate billed for assurance and related services that are reasonably related to the performance of the audit or review of the Company's financial statements and that are not disclosed in (1). Includes the review of the Company's interim consolidated financial statements and specified audit procedures not included as part of the audit of the consolidated financial statements.
3. Aggregate billed for tax compliance, tax advice, and tax planning, including the preparation of the Company's tax return.
4. Aggregate billed other than the services reported under (1), (2), and (3) above.
5. Audit services provided to Meren Coop are not included as Meren Coop was not a subsidiary of the Company during the 2024 financial year.

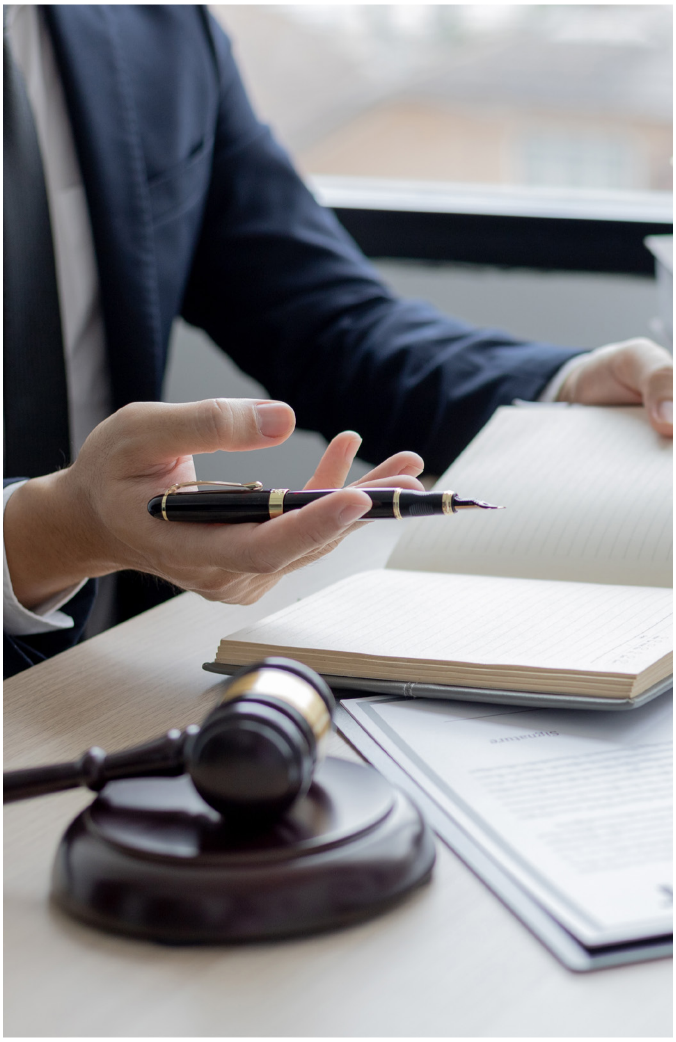
LEGAL PROCEEDINGS AND REGULATORY ACTIONS

LEGAL PROCEEDINGS

Neither the Company nor its material subsidiaries nor material properties are currently subject to any material legal proceedings or regulatory actions.

REGULATORY ACTIONS

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



INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Mr. Huw Jenkins is a director and Mr. Edwyn Neves is an officer of BTG Pactual, the parent of BTG Oil & Gas. Mr. Aldo Perracini, prior to the BTG Transaction, was a manager of BTG Oil & Gas. Mr. Perracini resigned as a manager of BTG Oil & Gas on March 19, 2025 as a result of the BTG Transaction.

On March 19, 2025, the Company completed the BTG Transaction, pursuant to which BTG Oil & Gas acquired an approximately 35.5% interest in the enlarged Company.

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

NAMES AND INTERESTS OF EXPERTS

This AIF contains references to estimates of reserves, contingent resources, prospective resources and estimates of future net revenue attributed to the Company's oil and gas assets.

Estimates of reserves, contingent resources, and estimates of future net revenue in respect of the Company's oil and gas interests in Nigeria are effective as of January 1, 2026, and are included in the report prepared by RISC (UK) Limited, an independent qualified reserves evaluator, in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook) and using Meren's Brent crude January 1, 2025 price forecasts, which has been approved for use by RISC (UK) Limited.

RISC (UK) Limited, nor any directors, officers, employees or consultants of RISC (UK) Limited, beneficially owns, directly or indirectly, any of the outstanding common shares of the Company. RISC (UK) Limited does not have any economic or beneficial interest in the Company or in any of its assets, nor is RISC (UK) Limited remunerated by way of a fee that is linked to the value of the Company.

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

The Company's independent auditors are PricewaterhouseCoopers LLP, Chartered Professional Accountants, who have prepared an independent auditor's report dated February 24, 2026 in respect of the Company's consolidated financial statements as at December 31, 2025 and 2024 and for the years then ended. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Company within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada, including the Rules of Professional Conduct Guidance of the Chartered Professional Accountants of Alberta, Canada and any applicable legislation or regulations.

ADDITIONAL INFORMATION

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

Additional financial information is provided in the Company's audited consolidated financial statements and the MD&A as at and for the year ended December 31, 2025.

SCHEDULE A: FORM NI-51-101F1

Meren Energy Inc.
(the "Reporting Issuer" or the "Company")

Statement of Reserves Data and Other Oil and Gas Information

For fiscal year ended December 31, 2025

This is the form referred to in item 1 of National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101").

Terms for which a meaning is given in NI 51-101 have the same meaning in this Form 51-101F1.

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PART 1. DATE OF STATEMENT

Item 1.1 Relevant Dates

This Statement of Reserves Data and Other Oil and Gas Information (the "Statement") of Meren Energy Inc. (formerly known as Africa Oil Corp.) ("Meren") is dated 12 February 2026.. The preparation date of this document is 12 February 2026., and the effective date of the information provided in this Statement is 1 January 2026.

PART 2. DISCLOSURE OF RESERVES DATA

RISC (UK) Limited ("RISC") prepared 3 reports dated 1-14 February 2026 (the "RISC reports"), in which it evaluated at year-end 2025, the oil and natural gas Reserves, Contingent Resources and Prospective Resources attributable to Meren in Nigeria, Equatorial Guinea and South Africa.

On 19 March 2025, Meren completed a transaction to consolidate all of the Meren Coöperatief U.A. (formerly known as Prime Oil & Gas Coöperatief U.A.) ("Meren Coop") shareholding in Meren, with Meren now owning 100% of Meren Coop and its reserves and production.

The year-end 2024 reserves were updated in March 2025 to reflect the completion of the transaction. That update was based only on the increased shareholding in Meren Coop, with no changes to production or forecasts. The reconciliation at year-end 2025 reflects changes from the March 2025 disclosure to year-end 2025. The reconciliation refers to the latest filed reserves position (the March 2025 filing), not the original year-end 2024 filing.

The disclosed Nigerian Reserves, Resources and other information pertain to Meren's entire interest in Petroleum Mining Lease ("PML") 2, PML 3, PML 4 and PML52 and Petroleum Prospecting Licenses ("PPL") 261 and PPL 2003, all located offshore Nigeria.

Meren holds an 8% working interest in PML 52 and PPL 2003 and a 16% working interest in PML 2, PML 3, PML 4 and PPL 261.

PML 52 contains part of the producing Agbami field. Agbami has been unitised over PML 52 and OML 128, approximately 62.5% and 37.5%, respectively. PML 2 contains the producing Akpo field. PML 3 contains the producing Egina field. PML 4 contains the planned Preowei development. PPL 261 contains the Egina South discovery.

The contents of the RISC report and RISC's estimates of Reserves and Resources are based on data provided to RISC by Meren. RISC has accepted, without independent verification, the accuracy and completeness of these data. All information provided to RISC was as of year-end 2025, and accordingly, some of this information may not be representative of current conditions.

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

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

The operators of the Agbami, Akpo, and Egina fields are also evaluating further options to drill additional infill wells, add incremental recovery projects, and develop undeveloped discoveries. These are classified as Contingent Resources. All the Contingent Resources are included in the Appendix to this statement.

In addition to the reserves and resources in the Nigerian assets, Meren has interests in assets in Nigeria (PML 2), South Africa (Block 3B/4B), and Equatorial Guinea (Blocks EG-31 & EG-18). RISC prepared a Prospective Resources report dated 7 March 2023 (the "RISC Orange Basin CPR"), in which it reported an independent audit of Block 3B/4B. The Contingent Resources and Prospective Resource volumes (including risked volumes) for Meren's assets in Nigeria, South Africa and Equatorial Guinea reported in the Appendix relate to updated evaluations for year-end 2025.

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

Item 2.1 Reserves Data (Forecast Prices and Costs)

The following table discloses, in the aggregate, Meren's gross and net proved, probable and possible Reserves, estimated using forecast prices and costs by product type, assessed at 1 January 2026. The term 'Forecast prices and costs' means future prices and costs used by RISC in the RISC Report. The fields are produced under Production Sharing Agreements ("PSAs") and Production Sharing Contracts ("PSCs"). The Gross Reserves are calculated as the total project sales volumes multiplied by the working interests in the PSAs and PSCs. The Net Oil Reserves are calculated using the economic interest booking methodology and include cost recovery oil, tax oil and profit oil as set out in the terms of the PSAs and PSCs. The table below indicates the reserves as of 1 January 2026.

Summary of Oil and Gas Reserves (Forecast Prices and Costs)

	Light and Medium Oil		Natural Gas		Oil Equivalent	
Reserve Category	**Gross (MMstb)**	**Net (MMstb)**	**Gross (Bscf)**	**Net (Bscf)**	**Gross (MMboe)**	**Net (MMboe)**
Proved						
Developed Producing	20.2	29.1	52.0	52.0	28.8	37.8
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	18.3	23.1	10.0	10.0	20.0	24.8
Total Proved	**38.4**	**52.2**	**62.0**	**62.0**	48.8	62.5
Probable	30.7	36.6	49.7	49.7	39.0	44.9
Total Proved plus Probable	**69.1**	**88.8**	**111.7**	**111.7**	87.7	107.4
Possible	23.7	25.4	51.9	51.9	32.4	34.0
Total Proved plus Probable plus possible	**92.8**	**114.2**	**163.6**	**163.6**	120.1	141.4

Notes:

1. The figures in the table may not add up precisely due to rounding.
2. Units are MMstb (million stock tank barrels) and Bscf (billion standard cubic feet).
3. Oil equivalent values are based on volumes Barrel of Oil Equivalent (BOE): 6 Mcf = 1 BOE. BOEs may be misleading particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
4. Gross Company Reserves are the total project sales volumes multiplied by Meren's working interest.
5. Net oil Reserves are Meren's net entitlement calculated using economic limit testing.
6. Gross and net Reserves for sales gas are equal as the gas terms are set out in the Gas Sales and Purchase Agreement, rather than the PSA, and the net Reserves are based on Meren's working interest.

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

Summary of Net Present Values of Future Net Revenue Forecast Prices and Costs ($ million)

	Before Income Taxes Discounted at (%/Year)					After Income Taxes Discounted at (%/Year)					Before Tax Net Value
Reserve Category	**0**	**5**	**10**	**15**	**20**	**0**	**5**	**10**	**15**	**20**	**10%/yr ($/Boe)**
Proved											
Developed Producing	516	503	487	470	454	338	335	327	317	306	12.9
Developed Non-Producing	-	-	-	-	-	-	-	-	-	-	-
Undeveloped	710	496	345	238	161	573	389	260	170	105	13.9
Total Proved	**1,225**	**998**	**832**	**708**	**614**	**911**	**724**	**588**	**487**	**411**	**13.3**
Probable	2,330	1,693	1,293	1,028	845	1,646	1,193	911	725	597	28.8
Total Proved plus Probable	**3,555**	**2,691**	**2,125**	**1,737**	**1,460**	**2,556**	**1,917**	**1,499**	**1,212**	**1,008**	**19.8**
Possible	2,015	1,373	997	763	608	1,417	961	696	531	423	29.3
Total Proved plus Probable plus Possible	**5,570**	**4,064**	**3,122**	**2,500**	**2,068**	**3,973**	**2,878**	**2,194**	**1,743**	**1,431**	**22.1**

Notes:

1. The figures in the table may not add up precisely due to rounding.
2. Units are US$ million.
3. Unit values are based on net reserve volumes Barrel of Oil Equivalent (BOE): 6 Mcf = 1 BOE. BOEs may be misleading particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
4. NPV is calculated effective 1 January 2026.

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

Total Future Net Revenue (Undiscounted) Forecast Prices and Costs (US$ millions)

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Abandonment / Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Proved	4,366	152	1,589	953	448	1,225	314	911
Proved plus Probable	7,707	317	2,370	1,017	448	3,555	999	2,556
Proved plus Probable plus Possible	10,098	451	2,589	1,040	448	5,570	1,597	3,973

Notes:

1. Units are US$ million.
2. Values are at 1 January 2026.

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

Net Present Value of Future Net Revenue by Production Group Forecast Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/ Year) ($ million)	Unit Value Before Income Taxes (Discounted at 10%/ Year) ($/BOE)
Proved	Light and Medium Crude Oil (including solution gas and associated by-products)	832	13.3
Proved plus Probable	Light and Medium Crude Oil (including solution gas and associated by-products)	2,125	19.8
Proved plus Probable plus Possible	Light and Medium Crude Oil (including solution gas and associated by-products)	3,122	22.1

Notes:

1. Units are US$ million.
2. Unit values are based on net reserve volumes Barrel of Oil Equivalent (BOE): 6 Mcf = 1 BOE. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
3. Values are at 1 January 2026.

A Summary of Contingent Resources and Prospective Resources as of 1 January 2026 has been included in the Appendix at the end of this document.

PART 3. PRICING ASSUMPTIONS

Item 3.1 Constant Prices Used in Supplementary Estimates

Not relevant.

Item 3.2 Forecast Prices Used in Estimates

RISC's price forecast used in preparing the Reserves data is provided in the table below, at the effective date of this statement (1 January 2026). The oil price forecast consists of a short-term forecast across 2026-2027 and then flat in real terms from 2028 onwards. Gas prices are based on the gas sales and purchase agreement, calculated by applying a monthly Brent adjustment and subtracting a handling fee.

Summary of Pricing and Inflation Rate Assumptions Forecast Prices & Costs

Year	Brent Oil Price US$/bbl	Gas Price US$/MMBTU	Inflation Rate (%/year)
2025 achieved sales price	72.2	1.0	-
2026	71.0	1.9	-
2027	73.3	2.0	2.0%
2028	74.6	2.0	2.0%
2029	76.1	2.0	2.0%
2030	77.6	2.1	2.0%
2031 and beyond	Escalation Rate of 2.0%	Escalation Rate of 2.0%	Escalation Rate of 2.0%

Notes:

1. Average oil prices received in 2025 include hedging.
2. Forecast prices include no hedging.
3. This summary table identifies benchmark reference pricing schedules used.
4. Inflation rates are used for forecasting prices and costs.
5. Gas price units are in US$ per million BTU (British Thermal Units).

PART 4. RECONCILIATION OF CHANGES IN RESERVES

Item 4.1 Reserves Reconciliation

The following table provides a reconciliation between gross Reserves disclosed on 20 March 2025 (effective date 31 December 2024) and this disclosure, which was prepared on 12 February 2026 (effective date 1 January 2026). We note the disclosure on 20 March 2025 was an update to reflect completion of the transaction to consolidate all of the Meren Coop shareholding in Meren, whereas a previous 27 February 2025 disclosure related to Meren's ownership at that time of 50% of Meren Coop.

	Light and Medium Oil (MMstb)			Conventional Natural Gas (Bscf)		
Gross	**Proved**	**Probable**	**Proved + Probable**	**Proved**	**Probable**	**Proved + Probable**
Effective date: 31 December 2024	44.8	34.1	78.9	89.8	46.0	135.8
Extensions and Improved Recovery	0.0	0.0	0.0	0.0	0.0	0.0
Resource Transfers	-0.9	-0.5	-1.4	-1.9	-1.2	-3.1
Technical Revisions	2.5	-2.9	-0.4	-6.2	4.9	-1.3
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	0.0	0.0	0.0	0.0	0.0	0.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	0.0	0.0	0.0	0.0	0.0	0.0
Production	8.0	0.0	8.0	19.7	0.0	19.7
Effective date: 1 January 2026	**38.4**	**30.7**	**69.1**	**62.0**	**49.7**	**111.7**

Notes:

1. The figures in the table may not add up precisely due to rounding.
2. Gross Company Reserves are the total project sales volumes multiplied by Meren's working interest.

Technical revisions in oil Reserves are mostly:

- Egina field – R1180 reservoir showed increase in GOR in 2025 with continued pressure depletion, leading to lower oil reserves. The Egina-18 sidetrack that was classified as undeveloped reserves in the previous reporting period has been moved to contingent resources for this year.
- Akpo field – Akpo 63 (undeveloped reserves) top hole was drilled but suspended due to BOP technical issues. The well is scheduled to complete drilling in Q4 2026 and will be brought on production thereafter. The Akpo West wells are performing better than anticipated in the previous reporting period. The Akpo Main water injector well that was classified as undeveloped reserves in the previous reporting period has been moved to contingent resources for this year. No additional development wells have been identified as undeveloped reserves or contingent resources by the operator. Several wells have been choked back, attempting to optimize oil recovery and reduce the rate of water production increase. Some wells have noted sand production and the operator has reduced the production rate of these wells to reduce sand production and preserve production equipment integrity.
- Agbami field – Oil reserves in the Agbami field have increased slightly at the 1P and 2P levels and decreased at the 3P level mainly reflecting increasing confidence in the developed reserves.

Technical revisions in gas Reserves are mostly:

- Egina field – R1180 reservoir showed increase in GOR in 2025 with continued pressure depletion, leading to higher gas reserves.
- Akpo field – Akpo West has performed better than anticipated during the last reporting period, leading to an increase in reserves from these wells. Additionally, the operator has brought several wells back online after minor well interventions during the last half of 2025 which has increased Akpo Main oil and gas production.

There are no economic factors impacting reserves revisions in YE2025.

PART 5. ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Item 5.1 Undeveloped Reserves

Reserves were first attributed to Meren at year-end 2019, after the acquisition of 50% of Meren Coop was completed.

New reserves and resources in 2025 are attributable to Meren, related to acquiring the remaining 50% of Meren Coop. These new reserves are listed in the table below.

The Proved and the Probable Undeveloped Reserves are associated with continuing long-term drilling and development programmes committed to under the approved field development plans. The fields are large offshore developments where drilling/production have been ongoing for several years and the attribution of Undeveloped Reserves is based on a continuation of, and the completion of, the approved Field Development Plans. For the Undeveloped Reserves: six further wells are planned for the Agbami field in 2027-2028; Akpo 63 (undeveloped reserves) is scheduled to complete drilling in Q4 2026 and will be brought on production thereafter; and four wells and a water shut-off are planned for Egina in 2027–2028. In attributing Proved and Probable Undeveloped Reserves to each field, the remaining wells are considered as a project, not as individual wells.

The Undeveloped Reserves also include the Preowei field development. The original Field Development Plan ("FDP") for this field was approved by the Nigerian authorities in 2019. The project FEED was suspended in April 2020 during the COVID-19 pandemic. FEED was re-started in November 2023, however, following a re-evaluation of higher costs and current market conditions, FEED was again suspended in Q3 2024 to pursue economic improvements. RISC understands that the operator (TotalEnergies) is continuing with subsurface studies to optimize the well count based on 4D seismic results and is negotiating with government and contractors. The operator plans to resume engineering work in Q1 2026 and to take a Financial Investment Decision at the end of 2026, with first oil scheduled for Q3 2029.

Since the year-end 2024 National Instrument filing, two production wells were drilled at Egina, and the incremental production volumes of these wells are included with Developed reserves. Additionally, at Akpo the top hole of AK-63 was drilled but the well was suspended due to BOP issues.

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

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

The table below shows the Undeveloped Reserves that were first attributed in each of the most recent financial years. The value in 2025 is due mainly to the acquisition of the remaining 50% of Meren Coop, which led to an increase in reserves.

Summary of Company Undeveloped Reserves (Forecast Prices & Costs)

Year First Attributed	Light/Medium Oil (MMstb)	Heavy Oil (MMstb)	Conventional Natural Gas (Bcf)
Proved Undeveloped			
2023	0.0	-	0.0
2024	0.4	-	0.8
2025	11.6	-	5.0
2026	0.0	-	0.0
Probable Undeveloped			
2023	0.0	-	0.0
2024	0.2	-	0.4
2025	4.6	-	5.8
2026	0.0	-	0.0

Notes:
1. Undeveloped Reserves were first attributed in March 2020 when the assets were acquired by Meren.
2. Net oil Reserves are Meren's net entitlement calculated using the economic limit testing.
3. Reserves are at 1 January 2026.

Item 5.2 Significant Factors or Uncertainties Affecting Reserves Data

The Agbami field straddles PML 52 (formerly OML 127) and OML 128. The Equity Determination in 2010 apportioned resources between block OML 127 and OML 128 at approximately 62.5% and 37.5%, respectively. The 2012 Final Redetermination was referred to an Expert, who determined an OML 127 equity of 72.064%. This final equity revision is still pending implementation, so RISC has retained the 2010 determination. If the 2012 Redetermination is implemented, Meren's Agbami equity share (and net Reserves) will increase.

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

- Agbami US$844 million.
- Akpo US$872 million.
- Egina US$630 million.
- Preowei US$250 million.

No specific technical uncertainties have been identified for these assets. However, these fields are geologically complex, and even with modern seismic techniques, uncertainty remains regarding reservoir extent, connectivity, and the timing of water and gas breakthrough at the wells.

The reader is also directed to the 'Risk Factors' section of the Meren financial statements for the year-end of 2025.

Item 5.3 Future Development Costs

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

Future Development Costs (Forecast Prices & Costs) ($ million)

Year	Proved Reserves	Proved plus Probable Reserves
2026	129	129
2027	186	186
2028	249	249
2029	220	220
2030	93	93
Subtotal	**876**	**876**
Remainder (to end of Field Life)	76	141
Total (Undiscounted)	**953**	**1,017**
Total (Discounted at 10%/year)	733	750

Notes:

1. The figures in the table may not be added up precisely due to rounding.
2. The Future Development Costs shown are associated with booked Reserves in the RISC report and do not necessarily represent the entire exploration and development plans.
3. Gross costs are based on the total project costs multiplied by Meren's interest.

The sources of funding for future costs of new wells and developments include cash flow from operations and existing debt facilities.

PART 6. OTHER OIL AND GAS INFORMATION

Item 6.1 Oil and Gas Properties and Wells

The properties with reserves are located offshore Nigeria, comprising an interest in PML 52 and an interest in PML 2, PML 3, PML 4.

PML 52 - Location and Partner Equities

The Agbami oil field is located in PML 52, offshore Nigeria, in water depths between 1,280 m and 1,650 m. It is 110 km south-southwest from the nearest Nigerian shoreline and approximately 350 km southeast of Lagos.

The Agbami field straddles licences PML 52 (formerly OML 127) and OML 128. The Equity Determination in 2010 apportioned resources between block OML 127 and OML 128 with 62.4619% and 37.5381% respectively. Star Deep Water Petroleum Nigeria, a wholly owned subsidiary of Chevron Corporation, operates the Agbami field under a production sharing agreement. Ownerships within PML 52 at the effective date were Meren (8%), Star Deep Water Petroleum Limited (32%) and Famfa Oil Limited (60%). In 2020, Meren acquired a 50% shareholder interest in Meren Coop, and in March 2025 this increased to 100%. The effective interest of Meren in the Agbami field increased from 2.498% to 4.997% following the transaction.

The PIA was passed into law on August 16, 2021, and introduced several changes to the petroleum industry in Nigeria.

PML 52 - Agbami Field

The field was discovered by well Agbami-1 in 1998, and the extension into the adjacent licence was proved by the Ekoli-1 well in 2000. The oil is light, with 45° to 47° API gravity. The field is developed via sub-sea wells tied back to a dedicated Floating Production Storage and Offtake (FPSO) vessel through steel catenary risers. Production commenced in June 2008, and peak production of 250,000 bopd (gross) was attained in 2009. At 31 December 2025, 30 producers, 5 gas injectors and 10 water injectors had been drilled. The field average oil production rate in 2025 was about 72,000 bopd. Cumulative oil production to 31 December 2025 was 1,148 MMstb for the field. There is no gas export, so all gas is re-injected, flared or used as fuel.

Reserves include 6 infill wells planned for 2027/8. Contingent Resources include 6 further infill wells, a notional 10-year lease extension, and the tie back of the Ikija discovery located in PPL 2003 also operated by Star Deep Water Petroleum Nigeria.

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

The title interests of PML 2, PML 3, PML 4 are held under two distinct but interlinked contractual structures that were set up when the licence was known as OML 130. A 50% interest is held by the Nigerian National Petroleum Corporation under a production sharing agreement (the "130 PSA") with South Atlantic Petroleum Limited ("SAPETRO") as the Contractor. SAPETRO subsequently assigned a 90% share of its interest as Contractor under the 130 PSA to CNOOC Exploration and Production Limited ("CNOOC"). The other 50% interest is held under an agreement, which was amended and renamed the production sharing agreement entered into by Total Upstream Nigeria Limited ("TUPNI") 48%, Meren 32% and SAPETRO 20%. The resulting interests were therefore TUPNI (24%), CNOOC (45%), Meren (16%) and SAPETRO (15%). In 2020, Meren acquired a 50% shareholder interest in Meren Coop, and in March 2025 this increased to 100% after Meren acquired the remaining 50% interest in Meren Coop. The working interest held by Meren in PML 2, PML 3, PML 4 and PPL 261 increased from 8% to 16% following completion of the transaction in March 2025.

PML 2 – Akpo Field

The Akpo field is located offshore Nigeria in PML 2, approximately 200 km from Port Harcourt, in water depths between 1,100 m and 1,300 m. The field is operated by TotalEnergies. Akpo was discovered by well Akpo-1 in 2000 and was appraised from 2000 to 2002. Akpo contains a critical fluid that can also be described as condensate or light oil with an original Gas Oil Ratio (GOR) of approximately 3,500 scf/bbl. There is a significant variation of fluid properties with depth, without sharp gas-oil contacts. Commerciality was declared in 2005, and the field was developed via sub-sea wells with four production flowline loops tied back to the FPSO through steel catenary risers. Production commenced in March 2009, and a plateau oil production of approximately 180,000 bopd (gross) was attained in 2010. Pressure maintenance at or near initial pressures is required and provided by both water and gas injection. Part of the produced gas is re-injected for pressure maintenance, and the remaining part is transported via an export line to the Nigeria LNG plant (NLNG) via the Amenam field. At 31 December 2025, there were 53 wells connected with 31 producers, 19 water injectors and 3 gas injectors. The undeveloped reserves well (BU-P3/AK-63) is partially drilled and scheduled for completion in Q4 2026 and online thereafter. Two contingent resource projects were identified as 'partially swept' and remain as contingent resources at year-end 2025. The field produced approximately 51,700 stb/d at 62.5% water-cut at the end of 2025. The cumulative oil production to 31 December 2025 was 702 MMstb. Cumulative gas production to 31 December 2025 was 2.9 Tscf, cumulative injection 0.99 Tscf and cumulative gas export was 1.69 Tscf.

PML 3 – Egina Field

The Egina oil field is located offshore Nigeria in PML 3, approximately 200 km from Port Harcourt and 20 km southwest of the Akpo field, in water depths between 1,150 m and 1,750 m. The field was discovered by well Egina-1 in 2003, which tested the southern compartment of Egina Main. The field was subsequently appraised from 2004 to 2006. The oil has 25° to 41° API gravity. The field is currently producing via sub-sea well loops tied back to an FPSO. The project was sanctioned in May 2013, and first oil was achieved on 29 December 2018. In 2019, the field ramped up to its plateau production rate of 208,000 bopd, with gas exports of 130 MMscf/d. The initial development drilling campaign on Egina started in December 2014 and was completed in 2019. In December 2025, there were 19 production wells and 16 water injector wells, and to the end of December 2025, Egina was producing approximately 54,500 stb/d and 95 MMscf/d with a 62% water-cut. Egina has achieved a cumulative production of 311 MMstb and 272 Bscf to 31 December 2025.

PML 4 – Preowei Field

Preowei is an undeveloped oil and gas discovery in PML 4, in water depths ranging between 1,100 m and 1,300 m. The field is 20 km northwest of Akpo and 29 km north of Egina. Preowei was discovered in 2003 by the Preowei-1B well. An appraisal well, Preowei-2, was drilled in 2005 and a further appraisal well, Preowei-3, was drilled in 2017. The field is operated by TotalEnergies. The FDP was approved by the Nigerian Authorities in Q2 2019. The FDP includes 9 producing wells and 9 water injectors; however, following an optimisation study, the operator plans to drill 8 production wells and 8 injectors. The operator is continuing with subsurface studies based on 2024 4D seismic results. A further 8 contingent wells (4 producers and 4 water injectors) may be drilled.

The subsea wells will be tied back to the Egina FPSO for oil and gas export. Following the tie-back, surplus gas will be exported via the Egina-Akpo gas line to the Bonny LNG plant, with commercial terms agreed upon under the Gas Sale and Purchase Agreement for Egina. Plateau production of 65,000 bopd is expected and start-up is scheduled for 2029, with additional Contingent Resources to start up in 2031.

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

Oil and Gas Wells

	Producing		Non-Producing	
Wells	**Gross**	**Net**	**Gross**	**Net**
Nigeria PML 52 and PML 2, PML 3, PML 4, PPL 261				
Oil	80	9.5	0	0.0
Gas	0	0.0	0	0.0
Total	**80**	**9.5**	**0**	**0.0**

Notes:

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

In addition to the properties above, Meren has interests in Contingent resources and Prospective Resources. These are detailed in the Appendix to this document.

Item 6.2 Properties with No Attributed Reserves

As of 1 January 2026, Meren had interests in properties in addition to those in the Nigerian portfolio. These properties contain Contingent Resources and Prospective Resources, and no reserves have been attributed to these properties. The properties with no attributed reserves are summarized in the table below:

Meren Properties with No Attributed Reserves[1]

Country	Block	Net Working Interest (1)	Gross Area (km^2)	Net Area (2) (km^2)	Commitments	Expiry Date
South Africa	3B/4B	18%	17,581	3,165	Minimum commitment: Reprocess and interpret existing 3D seismic, update prospect inventory, conduct commercial evaluations of prospects	Application Pending (3)
Equatorial Guinea	EG-31	80% (Operator)	1,276 (4)	1,021(4)	The First Exploration Sub-Period has a minimum spend of US$3 million focused on 3D seismic data reprocessing.	28 February 2028 (4)
Equatorial Guinea	EG-18	80% (Operator)	1,649	1,319	The First Exploration Sub-Period has a minimum spend US$4 million focused on 3D seismic data reprocessing.	28 February 2028 (5)

Notes:

1. Net Working Interests are subject to back-in rights, if any exist, of respective governments.
2. Net acreage is calculated by multiplying Gross Acreage by the current Net Working Interest.
3. RISC prepared a Prospective Resources report dated 7 March 2023 (the "RISC Orange Basin CPR"), in which it reported an independent evaluation of Block 3B/4B, South Africa.
4. The area of Block EG-31 was expanded on 23 December 2024. A one year extension of the First Exploration Sub-Period, in respect of Block EG-31 was granted on 2 December 2024. A further two year extension of the First Exploration Sub-Period in respect of Block EG-31 was granted on 17 December 2025.
5. A one year extension of the First Exploration Sub-Period in respect of Block EG-18 was granted on 5 December 2024. A further extension of the First Exploration Sub-Period of up to two years in respect of Block EG-18 was granted on 17 December 2025.

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

Please see Meren's financial statements, meeting materials, and corporate filings for the year ending 31 December 2025 for details on economic factors and uncertainties relating to properties with no attributed reserves.

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

Item 6.3 Forward Contracts

Meren'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 that Meren has physical price exposure. Meren uses a mix of financial derivatives and physical forward sales contracts to manage its commodity price risk and ensure stability in cash flows. Its strategy is to hedge between 70-100% of its post-tax net entitlement production for the next 12-months. As of December 31, 2025, Meren has a mix of physical and financial hedges.

For further details on Meren's hedging policy, please see Meren's financial statements, meeting materials and corporate filings for the year ending 31 December 2025.

Item 6.4 Tax Horizon

Meren is required to pay income taxes in Nigeria. For further information on Meren's tax status, please refer to Meren's Annual Information Form for the year ended 31 December 2025.

Item 6.5 Costs Incurred

The costs included in the following represent Meren's share of the total costs incurred for the assets. The figures in the following table reflect Meren's interests during 2025.

Costs incurred in the year ended 31 December 2025

US$ millions	Acquisition Costs	Exploration Costs	Development Costs	Production Costs	Other Costs
Nigeria	0	4[1,2]	89[1]	152[1]	26[3]
South Africa	8[4]	0[5]	0	0	0[6]
Equatorial Guinea	0	2	0	0	4[7]

Notes:

1. Costs are based on the total project costs throughout 2025.
2. Exploration costs relate to seismic purchase and acquisition, processing, and studies. No exploration wells were drilled.
3. Other Costs mainly relate to HCDF Levy, NDDC Levy and internal G&A costs allocated to the Nigerian assets (both local G&A and head office G&A) during the year.
4. On July 26, 2024, Meren signed an agreement with Eco (Atlantic) Oil & Gas Limited to acquire an additional 1.0% interest in Block 3B/4B from Azinam Limited, Eco (Atlantic) Oil & Gas Limited's wholly owned subsidiary, in exchange for all common shares and warrants over common shares held by Meren in Eco (Atlantic) Oil & Gas Limited. On January 13, 2025, Meren announced that it had completed this transaction. Meren's interest in Block 3B/4B increased by 1.0% to 18.0% and Meren ceased to be a shareholder in Eco (Atlantic) Oil & Gas Limited. The fair value of Meren's investment in Eco (Atlantic) Oil & Gas Limited on the day of the transaction was $8.0 million."
5. Nil, as Meren is fully carried for up to 2 wells.
6. Internal G&A costs allocated to the South African asset minus carry repayment receipts from Ricocure (Proprietary) Limited result in a value near zero.
7. Other Costs relate to internal G&A costs allocated to the Equatorial Guinea assets (both local G&A and head office G&A) during the year.

Item 6.6 Exploration and Development Activities

In 2025, two production wells were drilled at Egina, and at Akpo the top hole of AK-63 was drilled but suspended due to BOP issues. No other wells were drilled in PML 52, PML 2, PML 3, or PML 4. The figures in the following table reflect Meren's interests during 2025.

Wells drilled and completed in the year ended 31 December 2025

	Exploration Wells	Stratigraphic Test Wells	Oil Wells	Gas Wells	Service Wells	Dry Holes
Gross	0	0	3	0	0	0
Net	0.0	0.0	0.5	0.0	0.0	0.0

Notes:

1. Gross is the total number of wells drilled and completed on the properties.
2. Net is the sum of Meren's working interest in the gross wells.
3. One oil production well was drilled to the top hole only, left suspended until 2026.

Meren's most important current and likely development activities in Nigeria will be completing the planned drilling activities on the producing fields and developing Preowei, as described above under Undeveloped Reserves.

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

No exploration wells were drilled in 2025.

Exploration activities for the Equatorial Guinea assets included purchasing well data and new seismic data for reprocessing and interpretation, followed by desktop technical studies. Key seismic data has been integrated into the exploration evaluations for the two Equatorial Guinea blocks (Blocks EG-18 and EG-31), and prospect maturation continues for both blocks. Meren is currently in active dialogue with industry parties to farm down of its position in both blocks.

In South Africa, an application to enter into the Second Renewal period of the Exploration Right for Block 3B/4B was submitted in October 2024. The Block 3B/4B Exploration Right is currently in the 'white period'[1] whilst the application awaits approval from the South African authorities. In 2024 and 2025, technical work was undertaken by the operator, TotalEnergies, focusing on prospect maturation. Ongoing activities on the block include geological and geophysical studies (including evaluation and planning of exploration well locations) and 3D seismic reprocessing. Following the granting of an Environmental Authorisation by the Department of Mineral Resources and Energy for the Republic of South Africa on September 16, 2024 the legislative notification and appeals process is currently suspended pending a Supreme Court of Appeal judgement in respect of Block 5/6/7. The operator has stated that the current plan is to drill the first exploration well on Block 3B/4B as soon as the Environmental Authorization is confirmed and has identified Nayla, a prospect that lies in the northwest of the license area as the potential drilling target.

In Nigeria, the exploration well Akpo Far East is planned for drilling in 2026. This is classified as Prospective Resources and is included in the Appendix to this statement

Notes:

1. The white period is the time between the lapsing of an exploration period and the granting of a renewal period.

Item 6.7 Production Estimates

The following table sets out the estimated volumes of production for 2026 from PML 52, PML 2, PML 3 and PML 4 and reflects the estimates of gross proved Reserves and gross probable Reserves disclosed under Item 2.1 of this Statement.

Summary of Production Estimates by Production Group and Reserve Category (Forecast Prices & Costs)

Nigeria Reserves Category	Light and Medium Oil Gross (MMstb)	Natural Gas Gross (Bscf)	Oil Equivalent Gross (MMboe)
Proved			
Agbami	1.1	-	1.1
Akpo	2.2	12.9	4.4
Egina	2.1	2.5	2.5
Total Proved	**5.4**	**15.4**	**8.0**
Proved plus Probable			
Agbami	1.4	-	1.4
Akpo	2.7	18.6	5.8
Egina	2.8	3.5	3.4
Total Proved plus Probable	**6.9**	**22.1**	**10.5**

Notes:

1. The figures in the table may not add up precisely due to rounding.
2. Gross Company production is the total sales volumes multiplied by Meren's working interest.
3. Oil equivalent values are based on volumes Barrel of Oil Equivalent (BOE): 6 Mcf = 1 BOE. BOEs may be misleading particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
4. Values are at 1 January 2026.

Item 6.8 Production History

The production volumes, average realised price, royalties, and costs for each quarter of the 2025 financial year are provided in the table below. The figures in the following table reflect Meren's interests during 2025.

Production History for 2025

	Meren net entitlement production volume			Average realised price, royalties, gross costs and netback			
	Oil (MMstb)	Sales Gas (Bscf)	Total (MMboe)	Average Price Received ($/boe)	Royalties Paid ($/boe)	Gross Production Costs ($/boe)	Netback ($/boe)
2025 Q1	2.6	5.0	3.4	69.0	3.9	13.4	51.7
2025 Q2	2.4	5.0	3.2	37.7	3.1	11.5	23.1
2025 Q3	2.5	4.6	3.3	57.6	3.2	10.7	43.6
2025 Q4	2.1	5.1	2.9	51.3	2.5	12.0	36.8

Notes:

1. Average prices received in 2025 include hedging.
2. Gross costs are based on the total costs multiplied by Meren's paying interest.
3. Unit values are based on net reserve volumes Barrel of Oil Equivalent (BOE): 6 Mcf = 1 BOE. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
4. For Q1, Q2, Q3 and Q4 2025, the number of oil liftings was 5, 1, 3 and 3, respectively. The lower number of liftings in Q2 resulted in the Average Price Received being proportionately more exposed to gas sales, with a lower $/boe value.
5. The unit values for the Average Price Received are calculated using entitlement production.
6. Netback is calculated by subtracting the royalties paid and production costs from the revenue received.

The total production volumes for 2025 for each major field are provided in the table below. The values in the following table reflect Meren's interests during 2025.

Production History for 2025

Meren Production Volumes	Oil (MMstb)	Sales Gas (Bscf)
Agbami	1.3	-
Akpo	3.0	15.4
Egina	3.7	4.3
Total	**8.0**	**19.7**

Notes:

1. The figures in the table may not add up precisely due to rounding.
2. Gross Company production is the sales volume multiplied by Meren's working interest.

APPENDIX TO FORM NI-51-101F1: CONTINGENT RESOURCES AND PROSPECTIVE RESOURCES

PART 7. DISCLOSURE OF CONTINGENT RESOURCES DATA AND PROSPECTIVE RESOURCES DATA

Item 7.1 Contingent Resources Data

RISC has prepared an assessment of the crude oil and conventional natural gas Contingent Resources for Meren as of 1 January 2026. Due to the different levels of technical maturity of assets in the portfolio, some assets underwent a standard audit, whilst others were evaluated in more detail. These Contingent Resources are mostly in the offshore Nigerian licences (PML 52 and PML 2, PML 3, PML 4, PPL 261 and PPL 2003) associated with the Reserves in Item 2.1 of main F1 form. The operatorship and net interests in each field are consistent with the Reserves statements. Additionally, Meren has interests in Contingent Resources in block EG-31, offshore Equatorial Guinea.

The Contingent Resources are the following:

Agbami field – 6 infill wells

Six further infill drilling opportunities were identified in the Agbami field, providing both acceleration and incremental recovery in developed areas of the field. Additional work is required to select the best candidate drilling locations from these and other opportunities using the new 4DM3 seismic acquired in 2025. The first production from these wells is planned for 2029. The wells are estimated to cost approximately $533 million for drilling and completion, with an additional $152 million for facilities to tie-in the wells to the existing facilities. RISC has classified the project as Development on Hold.

Agbami field – 10 year lease extension

A notional 10-year lease extension scenario with production including 12 infill wells continuing to end 2054. RISC scaled Meren's 2C forecast by -40%/+60% to estimate 1C and 3C production profiles to account for the uncertainty. RISC has classified the project as Development Unclarified.

Akpo field – 2 infill wells

The operator is currently evaluating 2 infill production wells and one water injector well to be drilled in 2027. The water injector well was previously undeveloped reserves but has been reclassified as contingent resources by the operator and is scheduled to be drilled in Q3 2027. The two production wells were identified as 'partially flooded' using the 4D-M4 seismic data and require further technical analysis to progress. Estimated recovery for the 2 wells are 3 and 4.4 MMbbl of light oil, on a 2C basis. Drilling is scheduled for Q3/4 2027, with the first production in Q3 2027. Given the likely water ingress and further technical work required, RISC has classified the project as Development Unclarified.

Akpo field - Miscible Gas Injection project

Combined with the gas blowdown project (which was reclassified as reserves at YE2023) is the commencement of the Miscible Gas Injection (MGI) project. A pilot well is scheduled for Q4 2027, with three further wells to be drilled across Q4 2027 – Q1 2028. Gas injection is forecast to commence in Q1 2028 via the pilot well. The miscible gas injection in Upper A, Lower A and EF are simulated to create a reasonable incremental recovery of circa 43 MMstb. This project depends upon D reservoir gas blowdown to provide the gas for miscible injection and the results of the initial pilot well. The cost forecasts associated with this project are $123 million for drilling and completion and $120 million for the facilities.

RISC has classified the MGI project as Development Unclarified.

Preowei field - 8 additional wells

These wells are in addition to the Preowei development (classified as Reserves). The wells are currently planned to be drilled in 2030 and 2031. Capital costs are forecast to be approximately $407 million, with $327 million for the wells and $80 million for subsea facilities. There remains significant subsurface uncertainty, so the additional wells are contingent on the outcomes of the initial development stage. RISC has classified the project as Development On Hold.

Ikija - Development of discovered resources

Ikija is an undeveloped discovery in PPL 2003. It is planned as a tie-back to the Agbami FPSO, with first oil expected in 2032. Capital costs are forecast to be approximately $1,091 million and include: $107 million for an appraisal well to be drilled in Q4 2026; $403 million for 4 development wells to be drilled in 2030-2031; and $581 million for facilities. There is significant subsurface uncertainty, which will require further technical maturity and appraisal. There is no firm plan for the development concept, with both depletion and water injection being considered. Additionally, commercial and fiscal terms are not ready to enable tie-back to the Agbami unit. RISC classified the project as Development Unclarified.

Egina South - Development of discovered resources

The Egina South Discovery lies 20 km southwest of the Egina Field. The reservoir intervals are similar to the main Egina field. First oil is expected in 2032. Capital costs are forecast to be approximately $1,417 million for a 12-well subsea tieback, which includes $619 million for wells, $680 million for facilities, and $118 million for an appraisal well. The operator is revising the subsurface model, but the impact on STOIIP and recoverable volumes is unavailable. A further appraisal well may also be required. RISC has classified the project as Development on Hold.

Egina - 2 wells

The operator is evaluating two infill wells. The wells are in a maturation process, with further assessment to be carried out after integrity test results from nearby wells. The wells are currently scheduled to be drilled in Q2/3 2028. RISC has classified this project as Development On Hold.

Egina – Sidetrack well

A sidetrack well is planned for pressure support and to improve sweep efficiency. It is to be drilled in Q2 2028. RISC has classified this project as Development on Hold.

Gardenia in Block EG-31 - Development of discovered resources

The Block EG-31 Gardenia discovery is a four-way dip-closed structure proven by the 2004 Gardenia-1 well and its subsequent sidetracks. The well encountered a net 45 m gas/condensate pay zone and tested an 18 m net pay interval. The project is currently in the pre-feasibility/ concept screening phase. RISC has classified the project as Development Unclarified.

Chance of Development

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

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

- Agbami field (6 new infill wells): 63%
- Agbami field (10-year lease extension): 21%
- Akpo field 3 infill wells: 20%
- Akpo field miscible gas injection: 20%
- Preowei field (8 additional wells): 56%
- Ikija (development of discovered resources): 19%
- Egina South (development of discovered resources): 62%
- Egina infills (2 wells): 62%
- Egina well sidetrack: 58%
- Gardenia (development of discovered resources): 23%

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

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

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

Contingent Resources (Forecast Prices and Costs)

	Light & Medium Oil (MMstb)		Conventional Natural Gas (Bscf)	
Nigeria and Equatorial Guinea	**Gross**	**Net**	**Gross**	**Net**
Low Estimate (1C)	24.2	32.3	51.6	51.6
Best Estimate (2C)	37.3	46.4	91.2	91.2
High Estimate (3C)	49.8	59.6	159.1	159.1
Risked Best Estimate	12.5	14.9	23.8	23.8

Notes:

1. Gross Company volumes are the total project sales volumes multiplied by Meren's working interest.
2. Net oil volumes are Meren's net entitlement.
3. Gross and net sales gas volumes are based on Meren's working interest.
4. The "Risked Best Estimate" Contingent Resources account for the Chance of Development, which is defined as the probability of a project being commercially viable.
5. The resources for the Agbami 10-year Lease extension project are included in the Gross company volume totals. As the economic model only extends to 2050, the net entitlement for the Lease extension was calculated using the same percentage of gross to net as the Agbami reserves volumes.
6. The net entitlement for the Akpo miscible gas injection project was calculated using the same percentage of gross to net as the Akpo reserves volumes.
7. Values are at 1 January 2026.

The following table discloses, in aggregate, the net present value of the future net revenue attributable to the Contingent Resource categories in the preceding table that are in the Development Pending project maturity sub-class. At year-end 2025, there are no projects in this sub-class. These NPVs are estimated using forecast prices and costs before deducting future income tax expenses and are calculated without discount and using discount rates of 0 percent, 5 percent, 10 percent, 15 percent, and 20 percent.

Summary of Net Present Values of Future Net Revenue Forecast Prices and Costs

Net Present Values of Future Net Revenue ($ million)	Before Income Taxes Discounted at (%/Year)				
Contingent Resources Category	**0**	**5**	**10**	**15**	**20**
1C	0	0	0	0	0
2C	0	0	0	0	0
3C	0	0	0	0	0

Notes:

1. At 1 January 2026 there are no projects with Contingent Resources in the Development Pending project maturity sub-class.
2. Units are US$ million.

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

Item 7.2 Prospective Resources Data

RISC has prepared an audit of the crude oil and conventional natural gas Prospective Resources for Meren as of 1 January 2026.

The Prospective Resources are contained in the following licences:

Nigeria – PML-2

The Akpo Far East prospect is located to the east and downdip from the Akpo field on PML 2. The trap is defined by dip closure to the south and east, with stratigraphic trapping to the northwest. The reservoir comprises Miocene-aged 'G Sands' that form turbiditic deepwater fan lobes, equivalent to the G Sands in production in the Akpo main field.

The prospect has a secondary target, the 'B Sands'. RISC has not reviewed the volumes in this secondary target.

An exploration well is planned for 2026 to penetrate both the G and B sands. It aims to confirm a minimum volume of 69 MMstb and 363 Bcf of associated gas at an estimated cost of $US50 million.

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

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

South Africa – Block 3B/4B

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

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

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

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

Equatorial Guinea – Block EG-18

Block EG-18 is located within the Douala Basin or distal Rio Muni Basin offshore Equatorial Guinea. Meren is the Operator with 80% participating interest, with the remaining 20% participating interest held by GEPetrol. Water depths are circa 2,200 m. The Block is 150 km from the shore, west of the La Ceiba and Okume fields, and downdip of Vaalco's Venus development. The Block is 1,649 square kilometres in size and carries a range of prospects, including the key Jasper prospect. Hydrocarbons are expected to be a light oil.

Block EG-18 lies in the deep-water area, over the oceanic crust, and likely forms a separate petroleum province compared to the shelf. The main prospective play is the Aptian-Albian and Cenomanian-Turonian aged organic-rich oil prone shales deposited in a marine restricted environment, charging the overlying Late Cretaceous basin floor fans. The primary reservoir targets for Block EG-18 are Upper Cretaceous sandstones deposited in turbidite fans on the basin floor and break of slope settings.

The Jasper prospect is a stratigraphic trap with an amplitude expression consistent with a feeder channel and basin floor fan terminal lobe. The prospect is an anomalous AVO feature within a large, deepwater system. The seismic response brightens on the far stack exhibiting a Class II-III AVO anomaly. In contrast, other fans identified in the same deep-water complex do not exhibit the same AVO response. Seismic amplitudes and isochron mapping indicate potential trapping geometries, although up-dip stratigraphic seal remains the primary risk. Top and base seals are provided by Upper Cretaceous shales, and the Jasper feeder channel is mapped as containing a shale plug based on seismic amplitude changes.

Equatorial Guinea – Block EG-31

Block EG-31 is located within the distal Niger Delta offshore Equatorial Guinea in water depths of generally less than 100 m. Meren is the Operator with 80% participating interest, with the remaining 20% participating interest held by GEPetrol. The Block is 1,276 square kilometres in size and carries a range of prospects, including the Massif prospect.

The historical well data for Block EG-31 proves multiple reservoirs to be present across the Block as a series of submarine channels and turbidite fan lobes that are of similar thickness and quality to the productive reservoirs seen at the Alba field, approximately 20 km to the north.

Recently reprocessed 3D seismic demonstrated that the Massif Prospect is a four-way dip-closed structure at multiple reservoir levels. Massif is located up-dip of Gardenia and includes Upper Isongo Formation reservoirs that were flowed on test at Gardenia. The prospect includes zones in each of the Upper Isongo, Massive Sandstone, Lower Isongo, Base Isongo, in turbidite channel system and amalgamated fans. Meren showed that a single exploration well could target all reservoir levels.

The Whistler prospect is a ponded turbidite fan in the Upper Isongo reservoir. It is defined by anomalous seismic amplitudes that do not conform to structure with stratigraphic and structural/stratigraphic trapping mechanisms. Whistler sits in a structural low and relies on stratigraphic pinchout on three sides. The limits to the prospect are defined by the change from bright to dim amplitudes. The Whistler fan lies on trend with the regionally understood depositional fairways, with deposition from the north to south. The distal section of the Whistler fan has been penetrated at Bonito-1, finding distal but moderate net to gross sandstones.

The gross unrisked Undiscovered Petroleum Initially-In-Place (UPIIP) and gross unrisked Prospective Resources are presented in the table below. This is separated for oil prospects and gas prospects, with a total for the gross unrisked Prospective Resources.

Gross Unrisked UPIIP and Gross Unrisked Prospective Resources

Prospect Name	Unrisked UPIIP			Unrisked Prospective Resources – Light & Medium Oil (MMstb)			Unrisked Prospective Resources – Assoc. Gas (Bcf)		
Classification	**P90**	**P50**	**P10**	**1U (P90)**	**2U (P50)**	**3U (P10)**	**1U (P90)**	**2U (P50)**	**3U (P10)**
Oil Prospects, UPIIP as STOIIP (MMstb)									
Akpo Far East G sands (Nigeria)	153	342	458	31	82	183	104	370	1,246
Nayla Fan-SA (3B/4B)	1,118	2,066	3,777	277	518	951	504	953	1,767
Aardwolf (3B/4B)	903	1,313	1,884	222	327	475	384	586	882
Jasper (EG-18)	1,604	3,948	7,168	460	1,158	2,203	184	811	1,983
TOTAL for Oil Prospects	**3,778**	**7,669**	**13,287**	**990**	**2,085**	**3,812**	**1,176**	**2,720**	**5,878**
Gas Prospects, UPIIP as GIIP (Bscf)									
Massif (EG-31)	765	1,698	3,606	35	81	182	526	1,178	2,543
Whistler (EG-31)	1,371	2,365	3,572	46	89	153	877	1,530	2,346
TOTAL for Gas Prospects	**2,136**	**4,063**	**7,178**	**81**	**170**	**335**	**1,403**	**2,708**	**4,889**
All Prospects									
TOTAL for All Prospects				**1,071**	**2,255**	**4,147**	**2,579**	**5,428**	**10,767**

Notes:

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

Chance of Discovery and Chance of Development

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

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

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

Chance of Discovery and Chance of Development for each of the Prospective Resources

Country and Block	Prospect Name	Chance of Discovery	Chance of Development	Chance of Commerciality
Nigeria PML-2	Akpo Far East (G sands)	19%	90%	17%
South Africa, Block 3B/4B	Nayla Fan-SA	29%	75%	21%
	Aardwolf	17%	75%	12%
Equatorial Guinea, EG-18	Jasper	30%	69%	21%
Equatorial Guinea, EG-31	Massif	43%	75%	32%
Equatorial Guinea, EG-31	Whistler	18%	75%	14%

Notes:

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

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

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

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

Risked Prospective Resources

		Light & Medium Oil (MMstb)		Conventional Natural Gas (Bscf)	
Risked Best Estimate		**Gross**	**Net**	**Gross**	**Net**
Nigeria PML-2	Akpo Far East	14	2	63	10
South Africa, Block 3B/4B	Nayla Fan-SA	109	20	200	36
	Aardwolf	39	7	70	13
	Subtotal	**148**	**27**	**270**	**49**
Equatorial Guinea, EG-18	Jasper	243	195	170	136
Equatorial Guinea, EG-31	Massif	26	21	377	302
Equatorial Guinea, EG-31	Whistler	12	10	214	171
All Prospects	**Total**	**443**	**254**	**1,087**	**662**

Notes:

1. Figures in the table may not add up precisely due to rounding.
2. Gross volumes are the total project sales volumes.
3. Net volumes are the total project sales volumes multiplied by Meren's working interest.
4. The "Risked Best Estimate" Prospective Resources account for the Chance of Commerciality (ie the Chance of Discovery multiplied by the Chance of Development).
5. Values are at 1 January 2026.

Item 7.3 Forecast Prices Used in Estimates

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

SCHEDULE B:
FORM NI-51-101F2

Meren Energy Inc.
(the "Company")

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

To the board of directors of Meren Energy Inc. (the "Company"):

Due to the different levels of technical maturity of assets in the portfolio, some assets underwent a standard audit, whilst others were evaluated in more detail. We have audited and evaluated the Company's Reserves data, Contingent Resources data, and Prospective Resources data as of 1 January 2026. The Reserves data are estimates of proved Reserves and probable Reserves and related future net revenue as of 1 January 2026, estimated using forecast prices and costs. The Contingent Resources data are risked estimates of the volume of Contingent Resources and related risked net present value of future net revenue as of 1 January 2026 (for Development Pending projects), estimated using forecast prices and costs.

The Reserves data, Contingent Resources data and Prospective Resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the Reserves data, Contingent Resources data and Prospective Resources data based on our audit and evaluation.

We carried out our audit and evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

Those standards require that we plan and perform an audit and evaluation to obtain reasonable assurance as to whether the Reserves data, Contingent Resources data and Prospective Resources data are free of material misstatement. An audit and evaluation also includes assessing whether the Reserves data, Contingent Resources data and Prospective Resources data are in accordance with principles and definitions presented in the COGE Handbook.

The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable Reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the Reserves data of the Company audited and evaluated at 1 January 2026, and identifies the respective portions thereof that we have audited and evaluated and reported on to the Company's management:

US$ million			Proved + Probable Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
Independent Qualified Reserves Evaluator or Auditor	**Effective Date of Audit/ Evaluation Report**	**Location of Reserves**	**Audited**	**Evaluated**	**Reviewed**	**Total**
RISC	1 January 2026	Nigeria	2,125		-	2,125

Note:

1. Values are at 1 January 2026.

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

US$ million	Asset Description				Risked Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)		
Classification	**Independent Qualified Reserves Evaluator/ Auditor**	**Effective Date of Audit/ Evaluation Report**	**Location of Resources Other than Reserves**	**Risked V olume**	**Audited**	**Evaluated**	**Total**
Development Pending Contingent Resources (2C)	RISC	1 January 2026	Nigeria	Oil: 0.0 MMstb Gas: 0.0 Bscf	0.0		0.0

Notes:

1. The risked volume and NPV include only the Contingent Resources in the Development Pending sub-class.
2. At 1 January 2026 there is 1 project with Contingent Resources in the Development Pending project maturity sub-class.

Classification	Independent Qualified Reserves Auditor	Effective Date of Audit Report	Location of Resources Other than Reserves	Risked Oil Volume (MMstb)	Risked Gas Volume (Bscf)
Contingent Resources* (2C)	RISC	1 January 2026	Nigeria	13.4	1.8
	RISC	1 January 2026	Equatorial Guinea	1.5	22.1

Notes:

1. The volumes are for all other project maturity subclasses (i.e. excluding Development Pending).
2. Values are at 1 January 2026.

SCHEDULE B: FORM NI-51-101F2 - CONTINUED

In our opinion, the Reserves data, Contingent Resources data and Prospective Resources data, respectively audited and evaluated by us, have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the Reserves data, Contingent Resources data and Prospective Resources data that we reviewed but did not audit or evaluate.

We have no responsibility to update our reports referred to in paragraphs 5 and 6 for events and circumstances occurring after the effective date of our reports.

Since the Reserves, Contingent Resources, and Prospective Resources data are based on judgements regarding future events, the actual results will vary and the variations may be material.

Executed as to our report referred to above:

12 February 2026

RISC (UK) Limited
20 St Dunstan's Hill
London
EC3R 8HL
United Kingdom

Gavin Ward
Director

For and on behalf of RISC (UK) Limited

PART 1. DECLARATIONS

Item 1.1 Terms of Engagement

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

Item 1.2 Standard

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

Item 1.3 Limitations

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

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

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

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

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

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

Item 1.4 Independence

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

RISC makes the following disclosures:

- RISC is independent with respect to Meren and confirms that there is no conflict of interest with any party involved in the assignment;
- Under the terms of engagement between RISC and Meren, RISC will receive a time-based fee, with no part of the fee contingent on the conclusions reached, or the content or future use of this report. Except for these fees, RISC has not received and will not receive any pecuniary or other benefit whether direct or indirect for or in connection with the preparation of this report;
- Neither RISC Directors nor any staff involved in the preparation of this report have any material interest in Meren or in any of the properties described herein.

Item 1.5 Copyright

This document is protected by copyright laws and is intended for the use of the Meren only. Any unauthorised reproduction or distribution of the document or any portion of it may entitle a claim for damages. Neither the whole nor any part of this report nor any reference to it may be included in or attached to any prospectus, document, circular, resolution, letter or statement without the prior consent of RISC.

SCHEDULE C:
FORM NI-51-101F3

Meren Energy Inc.
(the "Company")

Report of Management and Directors on Reserves Data and Other Information

Terms to which a meaning is ascribed in NI 51-101 have the same meaning in this form.

SCHEDULE C: FORM NI-51-101F3 - CONTINUED

The Technical Committee of the board of directors of Meren Energy Inc. (the "Company") has reviewed the oil and gas activities of the Company and has determined that the Company had the reserves volumes as stated in the table below as of December 31, 2025:

	Light and Medium Oil		Natural Gas		Total Hydrocarbons	
Reserve Category	**Gross (MMstb)**	**Net (MMstb)**	**Gross (Bscf)**	**Net (Bscf)**	**Gross (MMstb)**	**Net (MMstb)**
Total Proved	38.4	52.2	62.0	62.0	48.7	62.5
Total Proved plus Probable	69.1	88.8	111.7	111.7	87.7	107.4
Total proved plus probable plus possible	92.8	114.2	163.6	163.6	120.1	141.5

Notes:

1. Figures in table may not add precisely due to rounding.
2. Units are MMstb (million stock tank barrels) and Bscf (billion standard cubic feet).
3. Oil equivalent values are based on volumes Barrel of Oil Equivalent (BOE): 6 Mcf = 1 BOE. BOEs may be misleading particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
4. 'Gross' Company reserves are the total project sales volumes multiplied by Meren's working interest.
5. 'Net' oil reserves are Meren's net entitlement reserves calculated using economic limit testing.

Meren Energy Inc. ("Meren") appointed RISC (UK) Limited ("RISC") to report on the: (a) Reserves, Contingent Resources and Prospective Resources it holds in Nigeria; (b) Contingent Resources and Prospective Resources it holds in Equatorial Guinea; and (c) Contingent Resources and Prospective Resources it holds in South Africa. The RISC report, as prepared by an independent qualified reserves evaluator or qualified reserves auditor, has been filed with the securities regulatory with respect to the financial year ended December 31, 2025.

The Technical Committee has determined that the Company had no reserves or resources within the properties that the Company held in regions other than those in RISC's report on: (a) Reserves and Contingent Resources Audit of PML 52, PML 2, PML 3, PML 4, PPL 261 & PPL 2003 offshore Nigeria; (b) Prospective Resources Audit of PML 52, PML 2, PML 3, PML 4, PPL 261 & PPL 2003 offshore Nigeria; (c) Reserves and Resources Audit for Equatorial Guinea, Block EG-31; (d) Reserves and Resources Audit for Equatorial Guinea, Block EG-18; (e) Reserves and Resources Audit for Block 3B/4B, South Africa . As per this determination, no reserves, contingent or prospective resources have been reported beyond those reported in the RISC report for Meren's year ended December 31, 2025.

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

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

Dr. Oliver Quinn

Dr. Oliver Quinn, Chief Executive Officer

Aldo Perracini

Aldo Perracini, Chief Financial Officer

Dr. Richard Norris

Dr. Richard Norris, Director

Ms. Cheryl Sandercock

Ms. Cheryl Sandercock, Director

SCHEDULE D: MANDATE OF THE AUDIT COMMITTEE

Meren Energy Inc.
(the "Company")

Mandate of the Audit Committee

(as adopted by the Board on August 12, 2025)

SCHEDULE D - CONTINUED

PART 1. PURPOSE OF THE AUDIT COMMITTEE

Item 1.1 The purpose of the Audit Committee is to ensure that the management of Meren Energy Inc. (the "Company") has designed and implemented an effective system of internal financial controls, to review and report on the integrity of the Company's financial statements and to review the Company's compliance with regulatory and statutory requirements as they relate to financial statements, taxation matters and disclosure of material risks and facts. The Audit Committee also has the responsibility to identify and understand the principal risks to the Company and its business and to report such risks to the Board to ensure there are systems in place to effectively monitor and manage those risks with a view to the long-term viability of the Company and in order to achieve its long-term strategic objectives.

Item 1.2 The Audit Committee oversees the accounting and financial reporting processes of the Company and its subsidiaries and all audits and external reviews of the financial statements of the Company on behalf of the Board, and has general responsibility for oversight of internal controls, accounting and auditing activities of the Company and its subsidiaries.

PART 2. MEMBERS OF THE AUDIT COMMITTEE

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

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

PART 3. MEETING REQUIREMENTS

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

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

PART 4. DUTIES AND RESPONSIBILITIES

Item 4.1 Appointment, Oversight and Compensation of Auditor

Item 4.1.1 The Audit Committee shall recommend to the Board:

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

b. the compensation of the Auditor.

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

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

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

Item 4.1.4 The Audit Committee shall review information, including written statements from the Auditor, concerning any relationships between the Auditor and the Company or any other relationships that may adversely affect the independence of the Auditor and assess the independence of the Auditor. The Audit Committee shall request, on a periodic basis, a formal written statement from the Auditor delineating all relationships that may reasonably be expected to affect the independence of the Auditor with respect to the Company and shall recommend that the Board take appropriate action, where necessary, in response to the Auditor's report to satisfy itself of the Auditor's independence.

Item 4.2 Non-Audit Services

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

Item 4.3 Review of Financial Statements etc.

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

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

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

Item 4.4 Review of Public Disclosure of Financial Information

Item 4.4.1 The Audit Committee shall review the Company's annual and interim press releases relating to financial results before the Company publicly discloses this information and shall review any prospectus/private placement memorandums that contain financial information.

Item 4.4.2 The Audit Committee must be satisfied that adequate procedures are in place for the review of the Company's public disclosure of financial information extracted or derived from the Company's financial statements, other than the public disclosure referred to in subsection 4.1, and must periodically assess the adequacy of those procedures.

Item 4.5 Review of Annual Audit

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

Item 4.5.2 The Audit Committee shall meet with the Auditor to discuss the Company's quarterly and annual financial statements and the Auditor's report including the appropriateness of accounting policies and underlying estimates.

Item 4.5.3 The Audit Committee shall satisfy itself that there are no unresolved issues between management and the Auditor that could affect the audited financial statements.

Item 4.5.4 The Audit Committee shall satisfy itself that, where there are unsettled issues that do not affect the audited financial statements (e.g. disagreements regarding correction of internal control weaknesses, or the application of accounting principles to proposed transactions), there is an agreed course of action leading to the resolution of these matters.

Item 4.5.5 The Audit Committee shall satisfy itself that there is generally a good working relationship between management and the AuditorAuditor.

Item 4.6 Review of Quarterly Review Engagements

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

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

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

Item 4.7 Internal Controls

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

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

Item 4.7.3 Acknowledging that it is the responsibility of the Board to identify the principal business risks facing the Company, the Audit Committee shall review the Company's tolerance for risk, identify and assess the significant risks facing the Company and review and approve the Company's policies for managing and controlling those risks.

Item 4.7.4 Review the effectiveness of the Company's policies and business practices which have an impact on the financial integrity of the Company, including those relating to internal auditing, insurance, accounting, information services and systems, cybersecurity and financial controls, management reporting and risk management.

SCHEDULE D - CONTINUED

Item 4.7.5 Review compliance under the Company's Code of Business Conduct and Ethics and the Anti-Corruption Policy and the maintenance of the gifts and hospitality register.

Item 4.7.6 The Audit Committee shall oversee the Company's approach to cybersecurity, including the operational status of the Company's technology systems and cybersecurity education and awareness.

Item 4.7.7 Where the Company appoints a head of risk, such role shall report to the Audit Committee.

Item 4.8 Compliance

Item 4.8.1 The Audit Committee shall:

a. ensure that the Auditor's fees are disclosed by category in the Annual Information Form in compliance with regulatory requirements;

b. disclose any specific policies or procedures the Company has adopted for pre-approving non-audit services by the Auditor including affirmation that they meet regulatory requirements; and;

c. assist the Corporate Governance and Nominating Committee with preparing the Company's governance disclosure by ensuring it has current and accurate information on;

   i. the independence of each Committee member relative to regulatory requirements for audit committees;

   ii. the state of financial literacy of each Committee member, including the name of any member(s) currently in the process of acquiring financial literacy and when they are expected to attain this status;

   iii. the education and experience of each Committee member relevant to his or her responsibilities as Committee member; and;

   iv. disclosure if the Corporation has relied upon any exemptions to the requirements for audit committees under regulatory requirements.

Item 4.8.2 The Audit Committee shall review material correspondence with financial regulators relating to compliance by the Company with regulatory requirements.

Item 4.9 Complaints and Concerns

Item 4.9.1 The Audit Committee shall establish procedures for:

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

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

Item 4.10 Hiring Practices

Item 4.10.1 The Audit Committee shall review and approve the Company's hiring policies regarding partners, employees and former partners and employees of the present and former Auditors of the Company.

Item 4.11 Hedging Policy

Item 4.11.1 The Audit Committee shall be responsible, on behalf of the Board, for approving the hedging policy of the Company from time to time, including with respect to commodity price, foreign exchange and interest rate hedging, financial or physical, intended to manage, mitigate or eliminate risks in relation to commodity price, foreign exchange and interest rate fluctuations. Management shall report to the Audit Committee at each quarterly Audit Committee meeting regarding hedges placed under the approved hedging policy. The Audit Committee shall regularly report to the Board on the approved hedging policy and on hedges placed.

Item 4.12 Other Matters

Item 4.12.1 The Audit Committee shall review and monitor all related party transactions which may be entered into by the Company.

Item 4.12.2 The Audit Committee shall review with management and the Auditors, if necessary, any litigation, claim or contingency, including tax assessments, that could have a material effect upon the financial position of the Company, and the manner in which these matters may be, or have been, disclosed in the financial statements.

Item 4.12.3 The Audit Committee shall review insurance coverage of significant business risks and uncertainties.

Item 4.12.4 The Audit Committee shall review policies and procedures for the review and approval of officers' expenses and perquisites.

Item 4.12.5 The Audit Committee shall satisfy itself that management has put into place procedures that facilitate compliance with the provisions of applicable securities laws and regulations relating to insider trading, continuous disclosure and financial reporting.

Item 4.12.6 The Audit Committee shall monitor the Company's sustainability reporting disclosures and processes particularly in the context of the EU's Corporate Sustainability Reporting Directive (**"CSRD")**. The Audit Committee shall monitor the processes carried out by the Company to identify the information reported in accordance with the CSRD and management's materiality assessments, and submit recommendations or proposals to ensure their integrity. The Audit Committee shall monitor the assurance of the annual and consolidated sustainability reporting and reporting on work performed in relation thereto conducted by external or internal auditors. The Audit Committee shall make recommendations to the Board in relation to such sustainability matters.

Item 4.12.7 The Audit Committee shall periodically review the adequacy of this Charter and recommend any changes to the Board.

Item 4.12.8 The Board may refer to the Audit Committee such matters and questions relating to the financial position of the Company and its affiliates as the Board from time to time may see fit.

PART 5. RIGHTS AND AUTHORITY OF THE AUDIT COMMITTEE AND THE MEMBERS THEREOF

Item 5.1 The Audit Committee has the authority to:

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

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

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

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

PART 6. MISCELLANEOUS

Item 6.1 Nothing contained in this Mandate is intended to extend applicable standards of liability under statutory or regulatory requirements for the directors of the Company or members of the Audit Committee. The purposes, responsibilities, duties and authorities outlined in this Mandate are meant to serve as guidelines rather than as inflexible rules and the Committee is encouraged to adopt such additional procedures and standards as it deems necessary from time to time to fulfill its responsibilities.

Item 6.2 The Committee Chair has the responsibility to make periodic reports to the Board, as requested, on financial matters relative to the Company.

Meren

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