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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2025
OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number: 1-32167

VAALCO Energy, Inc.
(Exact name of registrant as specified on its charter)

Delaware	**76-0274813**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

2500 CityWest Blvd.
Suite 400
Houston, Texas 77042
(Address of principal executive offices) (Zip Code)

(Registrant's telephone number, including area code): (713) 623-0801

Securities registered under Section 12(b) of the Exchange Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, par value $0.10	EGY	New York Stock Exchange
Common Stock, par value $0.10	EGY	London Stock Exchange

Securities registered under Section 12(g) of the Exchange Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer as defined in Rule 405 of the Securities Act. Yes o No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15d of the Act. Yes o No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes x No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer,", "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	o	Accelerated filer	x	Non-accelerated filer	o	Smaller reporting company	o

Emerging growth company o

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report x

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. o

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No x

As of June 30, 2025, the aggregate market value of the voting and non-voting common equity of the registrant held by non-affiliates was approximately $366.0 million based on a closing price of $3.61 on June 30, 2025.

As of March 10, 2026, there were outstanding 104,258,253 shares of common stock, $0.10 par value per share, of the registrant.

Documents incorporated by reference: Portions of the definitive Proxy Statement of VAALCO Energy, Inc. relating to the Annual Meeting of Stockholders to be filed within 120 days after the end of the fiscal year covered by this Form 10-K, which are incorporated into Part III of this Form 10-K.

VAALCO ENERGY, INC.

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Glossary of Certain Crude Oil, Natural Gas and Natural Gas Liquid (“NGL”) Terms

Terms used to describe quantities of crude oil, natural gas and NGLs

- *Bbl* — One stock tank barrel, or 42 United States (“U.S.”) gallons liquid volume, of crude oil or other liquid hydrocarbons.
- *Bbl/d* — Barrels per day.
- *Bcf* — One billion cubic feet.
- *Boe* — Barrel of oil equivalent. Volumes of natural gas converted to barrels of oil using a conversion factor of 6,000 cubic feet of natural gas to one barrel of oil.
- *BOEPD* — One Boe per day
- *BOPD* — One Bbl per day.
- *Km^2* — Square Kilometers.
- *M^3* — Cubic Meters.
- *MBbl* — One thousand Bbls.
- *MMBbl* — One million Bbls.
- *MBoe* — One thousand Boes.
- *MMBoe* — One million Boes.
- *MBopd* — One thousand Bbls per day.
- *MBOEPD* — One thousand Boes per day.
- *MCF* — One thousand cubic feet.
- *MCFD* — One thousand cubic feet per day.
- *MMBTU* – One million British Thermal Units.
- *MMcf* — One million cubic feet.
- *NGLs* — Natural Gas Liquids.
- *NRI* — Working interest volumes less royalty volumes, where applicable.
- *WI* — Working interest volumes

Terms used to describe legal ownership of crude oil, natural gas and NGLs properties, and other terms applicable to our operations

- *2025 RBL Facility (or the “2025 Facility”) —* our existing Reserves based lending facility.
- *BWE Consortium* — A consortium of the Company, BW Energy and Panoro Energy provisionally awarded two blocks, Niosi Marin Block (previously G12-13) and Guduma Marin Block (previously H12-13), in the 12th Offshore Licensing Round in Gabon.
- *C$* — means Canadian dollars.
- *Cardium* — The Cardium formation that spans a large area from southwest Alberta to northeast British Columbia, with the producing area concentrated along the eastern slopes of the Rocky Mountains to the northwest of Calgary.
- *Carried Interest* — Working Interest (as defined below) where the carried interest owner’s share of costs is paid by the non-carried working interest owners. The carried costs are repaid to the non-carried working interest owners from the revenues of the carried working interest owner.
- *Egypt* — Arab Republic of Egypt.
- *Etame Consortium* — A consortium of four companies granted rights and obligations in the Etame Marin block offshore Gabon under the Etame PSC.
- *FPSO* — A floating, production, storage and offloading vessel.
- *FSO* — A floating storage and offloading vessel.
- *Gabon* — Republic of Gabon.

- *Merged Concession* — The modernized concession that merged the West Bakr, West Gharib and NW Gharib concessions.
- *Merged Concession Agreement* — The agreement with the Egyptian General Petroleum Corporation (“EGPC”) for the Merged Concession signed by the Ministry of Petroleum of Egypt at an official signing ceremony on January 19, 2022.
- *NW Gharib* — The North West Gharib Concession area in Egypt.
- *Participating Interest* — Working Interest (as defined below) attributable to a non-carried interest owner adjusted to include its relative share of the benefits and obligations attributable to carried working interest owners.
- *PSC* — A production sharing contract.
- *Royalty Interest* — A real property interest entitling the owner to receive a specified portion of the gross proceeds of the sale of crude oil, natural gas and NGLs production or, if the conveyance creating the interest provides, a specific portion of crude oil, natural gas and NGLs produced, without any deduction for the costs to explore for, develop or produce the crude oil and, natural gas and NGLs.
- *TransGlobe Acquisition* — Acquisition of TransGlobe Energy Corporation *(“TransGlobe”)* completed on October 13, 2022.
- *West Bakr* — The West Bakr Concession area in Egypt.
- *West Gharib* — The West Gharib Concession area in Egypt.
- *Working Interest* — A real property interest entitling the owner to receive a specified percentage of the proceeds of the sale of crude oil, natural gas and NGLs production or a percentage of the production, but requiring the owner of the working interest to bear the cost to explore for, develop and produce such crude oil, natural gas and NGLs. A working interest owner who owns a portion of the working interest may participate either as operator or by voting his percentage interest to approve or disapprove the appointment of an operator and drilling and other major activities in connection with the development and operation of a property.
- *$* — means U.S. dollars.

Terms used to describe interests in wells and acreage

- *Gross crude oil, natural gas and NGLs wells or acres* — Gross wells or gross acres represent the total number of wells or acres in which a working interest is owned, before consideration of the ownership percentage.
- *Net crude oil, natural gas and NGLs wells or acres* — Determined by multiplying “gross” wells or acres by the owned working interest.

Terms used to classify reserve quantities

- *Proved developed crude oil, natural gas and NGLs reserves* — Developed crude oil, natural gas and NGLs reserves are reserves of any category that can be expected to be recovered:

  (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

  (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.
- *Proved crude oil, natural gas and NGLs reserves* — Proved crude oil, natural gas and NGLs reserves are those quantities of crude oil, natural gas and NGLs, 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) prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

  (i) The area of the reservoir considered as proved includes:

    (A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible crude oil or natural gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known crude oil elevation and the potential exists for an associated natural gas cap, proved crude oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first day of the month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

- *Proved undeveloped crude oil, natural gas reserve and NGLs reserves (“PUDs”)* — Proved undeveloped crude oil, natural gas and NGLs reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

- *Reserves* — Reserves are estimated remaining quantities of crude oil, natural gas, NGLs and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering crude oil, natural gas, NGLs or related substances to market, and all permits and financing required to implement the project.
- *Unproved properties* — Properties with no proved reserves.

Terms used to assign a present value to reserves

- *Standardized measure* — The standardized measure of discounted future net cash flows (“standardized measure”) is the present value, discounted at an annual rate of 10%, of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the Securities and Exchange Commission (“SEC”), using the 12-month unweighted average of first-day-of-the-month Brent prices adjusted for historical marketing differentials, (the “12-month average”), without giving effect to non–property related expenses such as certain general and administrative expenses, debt service, derivatives or to depreciation, depletion and amortization.

Terms used to describe seismic operations

- *Seismic data* — crude oil, natural gas and NGLs companies use seismic data as their principal source of information to locate crude oil, natural gas and NGLs deposits, both to aid in exploration for new deposits and to manage or enhance production from known reservoirs. To gather seismic data, an energy source is used to send sound waves into the subsurface strata. These waves are reflected back to the surface by underground formations, where they are detected by geophones that digitize and record the reflected waves. Computers are then used to process the raw data to develop an image of underground formations.
- *3-D seismic data* — 3-D seismic data is collected using a grid of energy sources, which are generally spread over several miles. A 3-D survey produces a three-dimensional image of the subsurface geology by collecting seismic data along parallel lines and creating a cube of information that can be divided into various planes, thus improving visualization. Consequently, 3-D seismic data is a more reliable indicator of potential crude oil, natural gas and NGLs reservoirs in the area evaluated.

As used in this Annual Report, the terms, “we,” “us,” “our,” the “Company” and “VAALCO” refer to VAALCO Energy, Inc. and its consolidated subsidiaries, unless the context otherwise requires.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (this “Annual Report”) includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”) and may also include forward-looking information within the meaning defined under applicable Canadian securities laws (collectively, “forward-looking statements”), which are intended to be covered by the safe harbors created by those laws. We have based these forward-looking statements on our current expectations and projections about future events. These forward-looking statements include information about possible or assumed future results of our operations. All statements, other than statements of historical facts, included in this Annual Report that address activities, events or developments that we expect or anticipate may occur in the future, including without limitation, statements regarding our financial position, operating performance and results, reserve quantities and net present values, market prices, business strategy, derivative activities, the amount and nature of capital expenditures, payment of dividends and plans and objectives of management for future operations are forward-looking statements. When we use words such as “anticipate,” “believe,” “estimate,” “expect,” “intend,” “forecast,” “outlook,” “aim,” “target,” “will,” “could,” “should,” “may,” “likely,” “plan,” and “probably” or the negative of such terms or similar expressions, we are making forward-looking statements. Many risks and uncertainties that could affect our future results and could cause results to differ materially from those expressed in our forward-looking statements include, but are not limited to:

- the impact of world health events, including any related impact on global demand for crude oil and crude oil prices, potential difficulties in obtaining additional liquidity when and if needed, disruptions in global supply chains and disruptions to our workforce;
- the impact of any future production quotas imposed by Gabon, as a member of the Organization of the Petroleum Exporting Countries (“OPEC”), as a result of agreements among OPEC, Russia and other allied producing countries with respect to crude oil production levels;
- the impact of the wide-ranging policy changes and numerous executive actions issued by the current U.S. presidential administration on topics including international trade, imposition of trade tariffs, energy resources, corporate taxes, global climate change initiatives, employment practices, corporate compliance programs, environmental regulations, as well as other matters;
- the macroeconomic, regulatory or other potential effects of a prolonged U.S. government shutdown;
- volatility of, and declines and weaknesses in crude oil and, natural gas and NGLs prices, as well as our ability to offset volatility in prices through the use of hedging transactions;
- the discovery, acquisition, development and replacement of crude oil, natural gas and NGLs reserves;
- impairments in the value of our crude oil, natural gas and NGLs assets;
- future capital requirements;
- our ability to maintain sufficient liquidity in order to fully implement our business plan;
- our ability to generate cash flows that, along with our cash on hand and our 2025 RBL facility, will be sufficient to support our operations and cash requirements;
- the ability of the BWE Consortium to successfully execute its business plan;

- our ability to attract capital or obtain debt financing arrangements;
- our ability to pay the expenditures required in order to develop certain of our properties;
- operating hazards inherent in the exploration for and production of crude oil, natural gas and NGLs;
- difficulties encountered during the exploration for and production of crude oil, natural gas and NGLs;
- the impact of competition;
- our ability to identify and complete complementary opportunistic acquisitions;
- our ability to effectively integrate assets and properties that we acquire into our operations;
- weather conditions;
- the uncertainty of estimates of crude oil, natural gas and NGLs reserves;
- currency exchange rates and regulations;
- unanticipated issues and liabilities arising from non-compliance with environmental regulations;
- the ultimate resolution of our abandonment funding obligations with the government of Gabon and the audit of our operations in Gabon currently being conducted by the government of Gabon;
- our limited control over the assets we do not operate;
- the ability of the FPSO in Cote d'Ivoire to return to service at the expected timeframe;
- the availability and cost of seismic, drilling and other equipment;
- difficulties encountered in measuring, transporting and delivering crude oil, natural gas, and NGLs to commercial markets;
- timing and amount of future production of crude oil, natural gas and NGLs;
- hedging decisions, including whether or not to enter into derivative financial instruments;
- general economic conditions, including any future economic downturn, the impact of inflation or tariffs, disruptions in financial credit and other disruptions resulting from geo-political events such as the Russian invasion of Ukraine, conflicts in the Middle East, including the United States-Israel-Iran war, trade tensions between the U.S. and China and U.S. military operations in Venezuela;
- our ability to enter into new customer contracts;
- changes in customer demand and producers' supply;
- actions by governments and other significant actors with respect to events occurring in the countries in which we operate;
- actions by our joint venture partners;
- compliance with, or the effect of changes in, governmental regulations regarding our exploration, production, and well completion operations, including those related to climate change;
- the outcome of any governmental audit;
- the anticipated impact on our business and operations of the OBBBA; and
- actions of operators of our crude oil, natural gas and NGLs properties.

The information contained in this Annual Report, including the information set forth under the heading "Item 1A. Risk Factors," identifies additional factors that could cause our results or performance to differ materially from those we express in forward-looking statements. Although we believe that the assumptions underlying our forward-looking statements are reasonable, any of these assumptions and therefore also the forward-looking statements based on these assumptions, could themselves prove to be inaccurate. In light of the significant uncertainties inherent in the forward-looking statements that are included in this Annual Report, our inclusion of this information is not a representation by us or any other person that our objectives and plans will be achieved. When you consider our forward-looking statements, you should keep in mind these risk factors and the other cautionary statements in this Annual Report.

Our forward-looking statements speak only as of the date the statements are made and reflect our best judgment about future events and trends based on the information currently available to us. Our results of operations can be affected by inaccurate assumptions we make or by risks and uncertainties known or unknown to us. Therefore, we cannot guarantee the accuracy of the forward-looking statements. Actual events and results of operations may vary materially from our current expectations and assumptions. Our forward-looking statements, express or implied, are expressly qualified by this

"Cautionary Statement Regarding Forward-Looking Statements," which constitute cautionary statements. These cautionary statements should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances occurring after the date of this Annual Report.

Risk Factor Summary

Below is a summary of our risk factors. The risks below are those that we believe are the material risks that we currently face but are not the only risks facing us and our business. If any of these risks actually occur, our business, financial condition and results of operations could be materially adversely affected. See "*Item 1A.Risk Factors*" beginning on page 29 and the other information included elsewhere or incorporated by reference in this annual report for a discussion of factors you should carefully consider before deciding to invest in our common stock.

- Our business requires significant capital expenditures, and we may not be able to obtain needed capital or financing to fund our exploration and development activities or potential acquisitions on satisfactory terms or at all.
- Provisions of our agreements could discourage an acquisition of us by a third-party.
- Unless we are able to replace the proved reserve quantities that we have produced through acquiring or developing additional reserves, our cash flows and production will decrease over time.
- The Company does not always control decisions made under joint operating agreements, and the parties under such agreements may fail to meet their obligations. In addition, we have limited control over the assets we do not operate.
- Our offshore operations involve special risks that could adversely affect our results of operations.
- Acquisitions and divestitures of properties and businesses may subject us to additional risks and uncertainties, including that acquired assets may not produce as projected, may subject us to additional liabilities and may not be successfully integrated with our business. In addition, any sales or divestments of properties we make may result in certain liabilities that we are required to retain under the terms of such sales or divestments.
- Our reserve information represents estimates that may turn out to be incorrect if the assumptions on which these estimates are based are inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present values of our reserves.
- If our assumptions underlying accruals for abandonment and decommissioning costs are too low, we could be required to expend greater amounts than expected.
- We could lose our interest in Block P in Equatorial Guinea if we do not meet our commitments under the production sharing contract.
- The FPSO in Côte d'Ivoire ceased hydrocarbon production on January 31, 2025 for scheduled maintenance. Our results will be adversely affected until the FPSO is returned to service which may be a time later than we expect.
- Commodity derivative transactions that we enter into may fail to protect us from declines in commodity prices and could result in financial losses or reduce our income.
- We are exposed to the credit risks of the third parties with whom we contract.
- Our business could be materially and adversely affected by security threats, including cybersecurity threats, and other disruptions.
- Current and future geopolitical events outside of our control could adversely impact our business, results of operations, cash flows, financial condition and liquidity.
- Production cuts mandated by the government of Gabon, a member of OPEC, could adversely affect our revenues, cash flow and results of operations.
- We have less control over our investments in foreign properties than we would have over our domestic investments.
- Our operations may be adversely affected by political and economic circumstances in the countries in which we operate.
- Inflation could adversely impact our ability to control costs, including operating expenses and capital costs.
- Our results of operations, financial condition and cash flows could be adversely affected by changes in currency exchange rates.
- We operate in international jurisdictions, and we could be adversely affected by violations of the U.S. Foreign Corrupt Practices Act and similar worldwide anti-corruption laws.
- Our business could suffer if we lose the services of, or fail to attract, key personnel.

- Our results of operations, financial condition and cash flows could be adversely affected by changes in currency regulations.
- Our results of operations, financial condition and cash flows could be adversely affected by changes to interest rates.
- The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced.
- Crude oil, natural gas and NGLs prices are highly volatile and a depressed price regime, if prolonged, may negatively affect our financial results.
- Exploring for, developing, or acquiring reserves is capital intensive and uncertain.
- Competitive industry conditions may negatively affect our ability to conduct operations.
- Weather, unexpected subsurface conditions and other unforeseen operating hazards may adversely impact our crude oil, natural gas and NGLs activities.
- An increased societal and governmental focus on Environmental, Social, and Governance ("ESG") matters, including climate change issues may adversely impact our business, hinder our access to investors and financing, and decrease demand for our product.
- We face various risks associated with increased opposition to and activism against crude oil, natural gas and NGLs exploration and development activities.
- Our operations are subject to risks associated with climate change and potential regulatory programs meant to address climate change; these programs may impact or limit our business plans, result in significant expenditures or reduce demand for our product.
- Compliance with applicable environmental laws and other government regulations could be costly and could negatively impact production.
- A significant level of indebtedness incurred under the 2025 Facility may limit our ability to borrow additional funds or capitalize on acquisition or other business opportunities in the future. In addition, the covenants in the 2025 Facility impose, and any successor debt agreement may impose, restrictions that may limit our ability and the ability of our subsidiaries to take certain actions. Our failure to comply with these covenants could result in the acceleration of any future outstanding indebtedness under the 2025 Facility or such successor debt agreement.
- The borrowing base under the 2025 Facility may be reduced pursuant to the terms of the 2025 Facility Agreement (defined below), which may limit our available funding for exploration and development. We may have difficulty obtaining additional credit, which could adversely affect our operations and financial position.

PART I

Item 1. Business

OVERVIEW AND STRATEGY

We are an independent energy company headquartered in Houston, Texas engaged in the acquisition, exploration, development and production of crude oil, natural gas and NGLs. We have a diversified, African-focused portfolio of production, development and exploration assets located in Gabon, Egypt, Cote d'Ivoire, Equatorial Guinea, Nigeria, as well as, prior to the Canada Asset Divestment (defined below), producing properties in Canada.

Our overall business strategy is to maximize the value of our current resources and expand into new development opportunities across our strategically complementary asset base. We intend to accelerate shareholder returns and increase shareholder value by controlling operating costs and capital expenditures, maximizing reserve recoveries and making disciplined strategic accretive acquisitions that meet our strategic and financial objectives. Specifically, we seek to:

- Focus on maintaining production and lowering costs to increase margins and preserve optionality to capitalize on an increase in crude oil, natural gas and NGLs prices;
- Manage capital expenditures related to our drilling programs so that expenditures can be funded by cash on hand and cash from operations;
- Continue our focus on operating safely and complying with internationally accepted environmental operating standards;
- Optimize production through careful management of wells and infrastructure;
- Maximize our cash flow and income generation;
- Continue planning for additional development of our properties;
- Preserve a strong balance sheet by maintaining conservative leverage ratios and exhibiting financial discipline;
- Opportunistically hedge against exposures to changes in crude oil, natural gas or NGLs prices; and
- Actively pursue strategic, value-accretive mergers and acquisitions of similar properties to diversify our portfolio of producing assets.

We believe that our quality portfolio, strong management and technical expertise specific to the markets in which we operate, and our ongoing focus on maintaining a competitive cost structure and disciplined capital allocation framework, position us to achieve our business strategy and navigate a variety of commodity price environments. Over the past years, we have delivered on our focused strategy and believe we will continue to do so with the organic growth programs across our diversified portfolio over the coming years.

Divestment of Non-Core Assets

On February 4, 2026, the Company entered into an asset purchase agreement (the "Canada APA") to sell all the operating assets in Canada (the "Canada Asset Divestment") to a third party purchaser for a purchase price of approximately $24.4 million (C$33.4 million), subject to customary adjustments. The Canada Asset Divestment closed on February 19, 2026 with an effective date of February 1, 2026 for an adjusted purchase price of $25.5 million (C$34.9 million), subject to additional customary post-closing adjustments. The Canada Asset Divestment represents the Company's complete exit of its Canadian oil and gas operations. Please see Part IV, Item 15., Note 4. *Acquisitions and Divestiture* and Note 20. *Subsequent Events*, to the Consolidated Financial Statements for further discussion on the Canada Asset Divestment.

SEGMENT AND GEOGRAPHIC INFORMATION

For additional operating segment and geographic financial information, see Part IV, Item 15., Note 19. *Segment Information* to the Consolidated Financial Statements. Our reportable operating segments are Gabon, Egypt, Cote d'Ivoire, Equatorial Guinea and, prior to the Canada Asset Divestment, Canada.

The following table sets out a brief comparative summary of certain key data for each of the Company's operating segments. Additional data and discussion are provided in Part II, Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations of this Annual Report on Form 10-K.

	Year Ended December 31, 2025			As of December 31, 2025	
	Production Volumes[1]	**Percentage of Total Production**	**Revenue**	**Year-End Estimated Proved Reserves**	**Percentage of Total Estimated Proved Reserves**
	(In MBoe)		(In thousands)	(in MBoe)	
Gabon	2,535	42 %	$ 181,738	10,001	23 %
Egypt	2,730	45 %	139,963	8,614	20 %
Cote d'Ivoire	111	2 %	18,397	18,210	43 %
Canada	667	11 %	19,174	6,158	14 %
Equatorial Guinea[2]	—	— %	—	—	— %
	6,043	100 %	$ 359,272	42,983	100 %

[1] Production volumes are reported on NRI basis.
[2] Undeveloped properties.

Gabon Segment

For the year ended December 31, 2025, our producing properties in Gabon produced approximately 2,535 MBoe or 42% of our total 2025 production. Our Gabon production for the period was 100% crude oil.

We own a 58.8% working interest in the Etame Marin block and we are the designated operator on behalf of the Etame Consortium. The Etame Marin block is located offshore Gabon in West Africa and covers an area of approximately 46,200 gross acres located 20 miles offshore in water depths of approximately 250 feet. The block is subject to a 7.5% back-in carried interest by the government of Gabon, which they have assigned to a third party. Our working interest will decrease to 57.2% beginning June 20, 2026 when the back-in carried interest increases to 10%.

The terms of the Etame PSC include provisions for payments to the government of Gabon for: royalties based on 13% of production at the published price and a shared portion of Profit Oil determined based on daily production rates, as well as a gross carried working interest of 7.5% (increasing to 10% beginning June 20, 2026) for all costs. The term of the Etame PSC extends through 2028 with two five-year options to extend the PSC (the "PSC Extension"). The PSC Extension provides us with the extended time horizon necessary to pursue developing the resources we have identified at Etame. The government of Gabon has elected to take its Profit Oil in-kind in all years presented.

We are a member of the BWE Consortium that was awarded the licenses for the Niosi Marin and the Guduma Marin exploration blocks in Gabon. These licenses are covered by PSCs entered into with the Gabonese Government (the "BWE Consortium PSC"). The PSC covering the Niosi block has an initial exploration period of five years ending in 2029 with a work commitment to acquire new 3D seismic data and drill one well, while the PSC covering the Guduma block has an initial exploration period of three years ending in 2027 with a work commitment to carry out geological and geophysical studies. The Niosi and Guduma blocks cover an area of 2,989 square kilometers and 1,929 square kilometers, respectively, and are adjacent to our Etame PSC. The Company holds a 37.5% non-operating working interest in these licenses.

Egypt Segment

For the year ended December 31, 2025, our Egypt Segment properties contributed approximately 2,730 MBoe or 45% of our total 2025 production. Our Egyptian production for the period was 100% crude oil.

In Egypt, our interests are spread across two regions: the Eastern Desert, which contains the Merged Concession, and the Western Desert, which contains the South Ghazalat concession. The Merged Concession is approximately 45,067 acres and the South Ghazalat concession is approximately 7,340 acres. Both of our Egyptian blocks are subject to PSCs with EGPC, the Egyptian government and VAALCO. We have an equal ownership interest, with EGPC owning the other portion, in the joint venture that has a 100% working interest in both PSCs. The PSC for the Merged Concession has a term ending in 2035. The term of the South Ghazalat PSC is scheduled to expire in 2039, subject to periodic evaluations and contingent upon continued successful drilling activities. Following the latest assessment and agreed-upon commitments, the South Ghazalat license is currently set to expire in 2027.

Cote d'Ivoire Segment

For the year ended December 31, 2025, the properties in Cote d'Ivoire produced approximately 111 MBoe or 2% of our total 2025 production. Our Cote d'Ivoire production for the period was 100% crude oil.

The Company holds a 27.4% non-operated working interest (30.4% paying interest) in CI-40 in the deepwater producing Baobab field in Block CI-40, offshore Cote d'Ivoire in West Africa. Crude oil from the Baobab field is produced to a dedicated FPSO with the associated natural gas delivered onshore via a subsea pipeline. The PSC license in Cote d'Ivoire has a term expiring in April 2038. The field has been developed with 24 subsea production wells and five water injector wells tied back to the FPSO. At year end, all production wells were shut in as the FPSO was off station in dry dock. Prior to shut in of the field, seven of these wells were in production, two were injecting and the other 20 were shut in. We also own a 21.05% non-operated working interest in OML 145, a non-producing discovery located offshore of Nigeria that is not expected to be developed at this time.

In connection with the planned dry dock refurbishment, the Baobab FPSO ceased hydrocarbon production on January 31, 2025, with the final crude oil lifting in February 2025. The vessel departed the field in late March 2025 for Dubai for the refurbishment work, which was completed in February 2026. The Baobab FPSO has commenced mobilization back to Cote d'Ivoire and is expected to return to offshore Cote d'Ivoire by late March 2026, with field production expected to restart in the second quarter of 2026. A rig has been secured for the planned development drilling program, which is expected to begin during the fourth quarter of 2026 following the FPSO's return to service. The drilling campaign is anticipated to bring meaningful additions to production from the main Baobab field in CI-40.

In February 2026, the Company became the operator with a 60% working interest in the Kossipo field on the CI-40 Block with a field development plan to be completed in the second half of 2026.

In March 2025, the Company farmed into the CI-705 block offshore Côte d'Ivoire as the operator with a 70% working interest and a 100% paying interest though a commercial carry arrangement with two other parties. The CI-705 block is located in the Ivorian Basin, west of the Company's CI-40 Block, where the Baobab and Kossipo oil fields are located. The block's first exploration period ends in May 2026. Entering into the block's second exploration period will require the commitment to reprocess seismic data and drill a well.

Canada Segment

For the year ended December 31, 2025, the properties in Canada produced approximately 667 MBoe or 11% of our total 2025 production. Our Canadian production for the period was 32% crude oil, 36% natural gas and 32% NGLs.

Prior to the Canada Asset Divestment, we owned production and working interests in Cardium light oil and Mannville liquids-rich gas assets in Harmattan, which is a core play in the Western Canadian Sedimentary Basis, and is located approximately 80 kilometers north of Calgary, Alberta. Prior to the Canada Asset Divestment, we also owned a 100% working interest in a large oil battery and a compressor station where a majority of oil volumes was processed. All gas was delivered to a third party non-operated gas plant for processing.

Following the Canada Asset Divestment, the Company plans to wind down its subsidiary in Canada.

Equatorial Guinea Segment

We currently own a 60% working interest in an undeveloped portion of Block P offshore Equatorial Guinea where we are the designated operator. In the event that there is commercial production from Block P, the Company is obligated to make a one-time potential future payment of $6.8 million to the national oil company of Equatorial Guinea, who is a party to the Block P PSC. The Block P PSC provides for a development and production period of 25 years, commencing from the first oil production from Block P. We have completed a feasibility study of a standalone production development opportunity of the Venus field discovery on Block P and submitted a plan of development ("Venus Plan of Development") to the Equatorial Guinea Ministry of Mines and Hydrocarbons ("EG MMH"), which was approved in September 2022.

After further negotiations and the agreement on certain terms relating to the joint operations were reached, the EG MMH directed that activities relating to the Venus Plan of Development resume in August 2023. These developments required a Third Amendment to the Joint Operating Agreement (“JOA”), which was approved by all parties to the JOA, and the EG MMH in February 2024. In late 2024, work commenced on the Front End Engineering and Design (“FEED”) to enable a Final Investment Decision (“FID”) on the Venus Plan of Development. In the second quarter of 2025, the Company completed the initial FEED study that confirmed the viability of the development concept and is currently evaluating alternative technical solutions which may deliver enhanced economic value. We currently have an existing plan of development of the Venus field discovery on Block P, which focuses on key areas of drilling evaluations, facilities design, market inquiries and metocean review.

Production Sharing Contracts

Exploration and production activities of our assets in Gabon, Egypt, Cote d'Ivoire, Nigeria and Equatorial Guinea are generally governed by PSCs.

Our oil entitlement under the PSCs is generally the sum of cost oil, profit oil and excess cost oil, if applicable. Under the terms of the PSCs, the Company is typically the contractor partner (“Contractor”) and bears the risk and cost of exploration, development, and production activities. In return, if exploration is successful, the Contractor receives entitlement to variable physical volumes of hydrocarbons, representing recovery of the costs incurred (“Cost Oil”) and a stipulated share of production after cost recovery (“Profit Oil”).

The Contractor may be obligated to make royalty payments to the host government of each country using a variable percentage based on gross daily production levels. The remaining oil production, after deducting the gross royalty, if any, is split between Cost Oil and Profit Oil. Cost Oil is up to a maximum percentage and is allocated to recover approved operating and capital costs spent on specific projects. Excess Cost Oil, which is Cost Oil less the actual cost recovery, is further shared between the host government and the Contractor. Except as otherwise disclosed, all crude oil sales are priced at current market rates at the time of sale.

In Egypt, our share of royalties is paid out of the government's share of production, while in Gabon, the government receives a fixed royalty rate of 13%. Additionally, the income tax to which the Contractor is subject to (“Profit Oil Tax”), is deemed to have been paid to the host government as part of the payment of Profit Oil or is captured in the entitled share of Profit Oil production paid in-kind to the host government, and therefore no additional tax burden is due. Under this arrangement taxation is based on a set percentage of average daily production volume.

DRILLING ACTIVITY

The drilling campaign in Egypt, which started in late 2024 and continued into 2025, contributed to consistent production growth. In the fourth quarter of 2025, the Company commenced its Phase Three Drilling Program in Gabon with the drilling of one well in the Etame field. After completing our drillings at the Etame platform, we expect to move the drilling rig to the SEENT and Ebouri platforms where we have several wells and workovers planned to enhance production and potentially add reserves. Significant development drilling is also expected to begin in Cote d’Ivoire in the fourth quarter of 2026 after the FPSO returns to service following the completion of the rig refurbishment.

The following table sets forth the number of net exploratory and development wells drilled in the last three years:

	2025			2024			2023		
	Productive	Dry	In Progress	Productive	Dry	In Progress	Productive	Dry	In Progress
Gabon									
Exploratory wells	—	—	—	—	—	—	—	—	—
Development wells	—	—	1	—	—	—	—	—	—
Egypt									
Exploratory wells	1	1	—	—	—	—	—	2	—
Development wells	16	—	1	2	—	—	16	—	—
Cote d'Ivoire									
Exploratory wells	—	—	—	—	—	—	—	—	—
Development wells	—	—	—	—	—	—	—	—	—
Canada									
Exploratory wells	—	—	—	—	—	—	—	—	—
Development wells	—	—	—	4	—	1	2	—	—

See Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations, Recent Operational Updates,” for additional description of Vaalco’s drilling and completion activities during the year ended December 31, 2025.

PRODUCTIVE WELLS

The following table sets forth information at December 31, 2025 relating to the productive wells in which we owned a working interest as of that date. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

	Productive crude oil wells		Productive natural gas wells	
	Gross	Net	Gross	Net
Gabon	14	8.2	—	—
Egypt	147	147	—	—
Cote d'Ivoire	7	1.9	—	—
Canada	70	68.3	54	51.1
Total Productive crude oil wells	238	225.4	54	51.1

ACREAGE

The following table sets forth information as of December 31, 2025 relating to our leasehold acreage.

	Developed		Undeveloped		Total	
Acreage in thousands	Gross	Net	Gross	Net	Gross	Net
Gabon	6.9	4.1	1,250.4	477.2	1,257.3	481.3
Egypt	29.2	29.2	23.3	23.3	52.5	52.5
Cote d'Ivoire	3.5	1.0	611.6	409.2	615.1	410.2
Canada	48.5	44.5	26.6	22.6	75.1	67.1
Equatorial Guinea	—	—	57.3	34.4	57.3	34.4
Total acreage	88.1	78.8	1,969.2	966.7	2,057.3	1,045.5

Summary of Acreage Terms

The expiration dates of the term of our concessions associated with each operating area are as follows:

	Term	Extension Option
Gabon		
Etame Marin	2028	Two 5-year options
Niosi Marin	2029	3 years
Guduma Marin	2027	3-year and 2-year options
Egypt		
Merged Concession	2035	5 years
Western Desert	2027	—
Cote d'Ivoire		
Block CI-40	2038	—
Block CI-705	2026	30-month and 24-month options
Equatorial Guinea	25 years from first oil production	

For Canada, a significant portion of undeveloped acres is generally held by production by areas that are producing reserves. At December 31, 2025, approximately 67% of Canada's net undeveloped acreage (15,102 acres) has no expiration risk within the next five years (2026 through 2030).

RESERVE INFORMATION

Estimated Reserves and Estimated Future Net Revenues

Reserve Data

The tables below set forth our estimated net proved reserve quantities for the year ended December 31, 2025. Our reserves information was evaluated by the independent petroleum engineering firm, Netherland, Sewell & Associates, Inc. ("NSAI"). Prior to 2025, reserves information for Canada was independently evaluated by GLJ Ltd. ("GLJ"). The proved reserve quantities are calculated based on our NRI.

	Year Ended December 31, 2025			
	Crude Oil (MBbls)	Natural Gas (MMcf) (1)	NGLs (MBbls)	Total (MBoe)(1)
Proved developed reserves				
Gabon	5,287	—	—	5,287
Egypt	8,177	—	—	8,177
Cote d'Ivoire	—	—	—	—
Canada(2)	1,179	9,059	1,329	4,018
Total proved developed reserves	14,643	9,059	1,329	17,482
Proved undeveloped reserves				
Gabon	4,714	—	—	4,714
Egypt	437	—	—	437
Cote d'Ivoire	17,011	6,954	—	18,210
Canada(2)	1,163	3,150	452	2,140
Total proved undeveloped reserves	23,325	10,104	452	25,501
Total proved reserves	37,968	19,163	1,781	42,983

(1) To convert Natural Gas to MBoe, MMcf is divided by 6 for Canada reserves, and MMcf is divided by 5.8 for Cote d'Ivoire reserves.
(2) Proved developed and proved undeveloped reserves in Canada attributed to assets held for sale as of December 31, 2025.

In accordance with the current SEC guidelines, estimates of future net cash flows from our properties and the present value thereof are made using the average of the first-day-of-the-month price for each of the twelve months of the year adjusted for quality, transportation fees and market differentials. Such prices are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations.

For 2025 and 2024, the adjusted average prices used for our reserves estimates were as follows:

	Year Ended December 31,	
	2025	2024
Crude Oil ($/Bbl)		
Gabon	$ 66.60	$ 81.08
Egypt	$ 57.66	$ 65.48
Cote d'Ivoire	$ 68.95	$ 79.70
Canada	$ 61.61	$ 69.12
Natural Gas ($/Mcf)		
Cote d'Ivoire	$ 2.77	$ 2.77
Canada	$ 1.07	$ 0.95
Natural Gas Liquids ($/Bbl)		
Canada		
Ethane	$ 2.90	$ 3.52
Propane	$ 19.67	$ 19.46
Butane	$ 25.88	$ 30.68
Condensates	$ 62.44	$ 69.59

Standardized Measure

The following table sets forth the standardized measure of discounted future net cash flows:

	As of December 31,		
	2025	2024	2023
		(in thousands)	
Gabon	$ 31,561	$ 73,011	$ 107,824
Egypt	118,052	135,139	161,747
Cote d'Ivoire	232,625	124,143	—
Canada[(1)]	27,771	47,107	72,363
Standardized measure of discounted future net cash flows	$ 410,009	$ 379,400	$ 341,934

[(1)] Discounted future net cash flows in Canada attributed to assets held for sale as of December 31, 2025.

The information set forth in the tables includes revisions for certain reserve estimates attributable to proved properties included in preceding years' estimates. Such revisions are the result of additional information from subsequent completions and production history from the properties involved or the result of an increase or decrease in the projected economic life of such properties resulting from changes in product prices, estimated operating costs and other factors. Crude oil amounts shown for Gabon, Egypt and Cote d'Ivoire are recoverable under the respective PSCs, and the reserves in place at the end of the contract remain the property of each host government. The reserves at the end of the contract, including extensions, are not included in the table above.

We do not reflect proved reserves on discoveries in our reserve estimates until such time as a development plan has been prepared and approved by our joint venture owners and the host government, where applicable.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. Reserve engineering is a subjective process of estimating underground accumulations of crude oil, natural gas and NGLs that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of crude oil, natural gas and NGLs that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future crude oil, natural gas and NGLs sales prices may all differ from those assumed in these estimates. The standardized measure of discounted future net cash flows should not be construed as the current market value of the estimated crude oil, natural gas and NGLs reserves attributable to our properties.

Proved Undeveloped Reserves

Historically, we have reviewed on an annual basis all of our proved undeveloped reserves ("PUDs") to ensure an appropriate plan for development exists.

The following table discloses our estimated PUD reserve activities:

	Proved Undeveloped Reserves
	(MBoe)
Beginning proved undeveloped reserves at December 31, 2024	24,128
Undeveloped reserves converted to developed reserves	(1,172)
Revisions	1,326
Extensions and discoveries	1,219
Ending proved undeveloped reserves at December 31, 2025	25,501

Our PUD reserves at December 31, 2025 increased by 1.4 MMBoe, primarily due to:

Conversion to Proved Developed — Conversions of 1.2 MMBoe are attributable to our Egypt segment where we had four wells, which were previously classified as PUDs, were drilled and converted to proved developed producing ("PDP") as part of the 2025 drilling program. We also had one well in our Gabon segment, which was previously classified as PUD and was converted to PDP due to operational optimization where the reserves were confirmed to be accessible through existing infrastructure. The Company spent approximately $19.0 million in 2025 to convert PUDs to PDPs.

Revisions of Previous Estimates — We had total net positive revisions of 1.3 MMBoe in 2025. We had an increase of 1.9 MMBoe from our Cote d'Ivoire segment which includes increased recovery expectations from the upcoming Phase 5 drilling program supported by additional technical analysis. We also had an additional total upward revision of 0.4 MMBoe due to future well performance expectations in Egypt and updates to the gas supply in Gabon. These positive revisions were offset by negative revisions of 1.0 MMBoe in Canada due to wells that were not reasonably expected to be developed within the five-year timeframe in accordance with the SEC guidance.

Extensions and Discoveries — Extensions and discoveries of 1.2 MMBoe are associated with the drilling program in Gabon that extended the Etame Field and added new, proved undeveloped locations on the Company's existing acreage in the Etame block.

As of December 31, 2025, we plan to drill all scheduled PUD locations within the next five years and within the five years following the initial disclosure of the PUDs as proved reserves. All PUDs are tracked with respect to the year the reserves were initially booked to verify compliance. The PUD schedule of the Company is reviewed and approved by management as part of our reserves control process and the schedule is also reviewed by our independent petroleum engineers.

Controls over Reserve Estimates
Our policies and practices regarding internal controls over the recording of reserves are structured to objectively and accurately estimate our crude oil, natural gas, and NGLs reserves quantities and present values in compliance with SEC regulations and generally accepted accounting principles in the U.S. ("GAAP"). Compliance with these rules and regulations with respect to our reserves is the responsibility of the Technical & Reserves Committee of the Board of Directors (the "Technical & Reserves Committee") and our reservoir engineer, who is our principal engineer. Our principal engineer has over 25 years of experience in the crude oil and natural gas industry, including over five years as a reserve evaluator and trainer, and is a qualified reserves estimator, as defined by the Society of Petroleum Engineers' standards. Further professional qualifications include degrees in geological engineering and petroleum engineering, with a Master's

degree in petroleum engineering, extensive internal and external reserve training, and asset evaluation and management. In addition, the principal engineer is an active participant in industry reserve seminars, professional industry groups and is a member of the Society of Petroleum Engineers. The Technical & Reserves Committee meets periodically with senior management to discuss matters and policies related to reserves.

Our reserves estimation process involves methods generally accepted in the industry to assess our proved reserves, including production decline curve analysis methods, and may include volumetric methods, material balance methods, and reservoir simulation methods, or a combination of these methods, as well as taking into account economic parameters and considerations in finalizing these assessments, as appropriate. Technical information used by us to assess our proved reserves estimates may include geological, geophysical, engineering and financial data as well as other relevant static and dynamic data. In order to satisfy the requirements for establishing a reasonable certainty for proved reserves, including material increase in proved reserves estimates, we adopt field-tested repeatable and consistent reliable technologies, which may include, among others, logging, 3D and 4D seismic data, rock core analyses, static or dynamic pressure tests and production well testing, as appropriate. Where appropriate analogous reservoirs are available, we will use analogous reservoir parameters to enhance the quality of our reserve assessment results so as to be consistent with the reliable results required for proved reserves assessment as specified in applicable SEC rules.

Our controls over reserve estimation include engaging and retaining qualified independent petroleum and geological firms with respect to reserves information. We provide information to our independent reserve engineers about our crude oil, natural gas and NGLs properties in Gabon, Egypt, Cote d'Ivoire and Canada which includes, but is not limited to, production profiles, ownership and production sharing rights, prices, costs and future drilling plans. Our independent reserve engineers prepare their own estimates of the reserves attributable to our properties. The reserves estimates for our Gabon, Egypt, Cote d'Ivoire and Canada assets shown herein have been independently evaluated by NSAI and our Technical & Reserves Committee. Reserves estimates for Canada assets prior to 2025 had been independently evaluated by GLJ.

NET VOLUMES SOLD, PRICES, AND PRODUCTION COSTS

Net volumes sold, average sales prices per unit, and production costs per unit for our 2025, 2024 and 2023 operations are shown in the tables below.

	Production Volumes [2]			Sales Volumes [2]			Average Sales Price [2]			Average Production Cost [2]
	Crude Oil (MBbl)	Natural Gas (MMcf)	NGLs (MBbl)	Crude Oil (MBbl)	Natural Gas (MMcf)	NGLs (MBbl)	Crude Oil (Per Bbl)	Natural Gas (per Mcf)	NGLs (Per Bbl)	Total (per BoE)
Year Ended December 31, 2025										
Gabon	2,535	—	—	2,735	—	—	$ 65.76	$ —	$ —	$ 30.96
Egypt	2,730	—	—	2,730	—	—	51.27	—	—	19.61
Cote d'Ivoire	111	—	—	238	—	—	77.36	—	—	41.80
Canada	214	1,449	212	214	1,449	212	61.65	1.78	20.12	12.68
Total	5,590	1,449	212	5,917	1,449	212	$ 56.11	$ 1.78	$ 20.12	$ 24.83
Year Ended December 31, 2024										
Gabon	2,783	—	—	2,584	—	—	$ 78.81	$ —	$ —	$ 24.08
Egypt	2,585	—	—	2,585	—	—	56.47	—	—	19.64
Cote d'Ivoire [1]	1,058	—	—	1,223	—	—	77.74	—	—	31.08
Canada	350	1,542	269	350	1,542	269	70.69	1.04	25.43	12.99
Total	6,776	1,542	269	6,742	1,542	269	$ 65.64	$ 1.04	$ 25.43	$ 22.51
Year Ended December 31, 2023										
Gabon	3,197	—	—	3,196	—	—	$ 79.80	$ —	$ —	$ 27.26
Egypt	2,771	—	—	2,771	—	—	58.11	—	—	19.77
Canada	334	1,528	270	334	1,528	270	71.88	1.93	26.58	11.02
Total	6,302	1,528	270	6,301	1,528	270	$ 69.84	$ 1.93	$ 26.58	$ 22.16

(1) Reflects sales and production costs from April 30, 2024 through December 31, 2024 related to the Svenska Acquisition.
(2) The production volumes, average sales price, sales volumes and per Boe information are reported on NRI basis.

AVAILABLE INFORMATION

VAALCO Energy, Inc. is a Delaware corporation, incorporated in 1985 and headquartered at 2500 CityWest Blvd., Suite 400, Houston, Texas 77042. Our telephone number is (713) 623-0801 and our website address is www.vaalco.com. We make available, free of charge on our website, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports, at https://www.vaalco.com/investors/sec-filings as soon as reasonably practicable after such reports are electronically filed with or furnished to the SEC. These reports and other information are also available on the SEC's website at https://www.sec.gov. Information contained on our website and the SEC's website is not incorporated by reference into this Annual Report. We have placed on our website copies of charters for our Audit Committee, Compensation Committee and Environmental, Social and Governance Committee as well as our Code of Business Conduct and Ethics ("Code of Ethics"), Corporate Governance Principles and Code of Ethics for the CEO and Senior Financial Officers. Stockholders may request a printed copy of these governance materials by writing to the Company Secretary, VAALCO Energy, Inc., 2500 CityWest Blvd., Suite 400, Houston, Texas 77042. We intend to disclose updates, waivers or amendments to our Code of Ethics and Code of Ethics for the CEO and Senior Financial Officers on our website within four business days following the date of such update, waiver or amendment.

CUSTOMERS

For the years ended December 31, 2025, 2024 and 2023, our revenue concentration by customer for each operating segment are shown on the table below.

	Year Ended December 31,		
	2025	**2024 [1]**	**2023**
Gabon	100%	100%	100%
Egypt	100%	100%	62% and 38%
Cote d'Ivoire	100%	87% and 13%	—%
Canada	51%, 20% and 15%	41%, 32% and 21%	52%, 37% and 7%

(1) For Cote d'Ivoire, reflects sales from April 30, 2024 through December 31, 2024 related to the Svenska Acquisition.

EMPLOYEES AND HUMAN CAPITAL RESOURCE MANAGEMENT

We operate on the fundamental philosophy that people are our most valuable asset as every person who works for us has the potential to impact our success. Identifying quality talent is at the core of everything we do and our success is dependent upon our ability to attract, develop and retain highly qualified employees. Our core values include honesty/integrity, treating people fairly, high performance, efficient and effective processes, open communication and being respected in our local communities. These values establish the foundation on which our culture is built and represent the key expectations we have of our employees. We believe our culture and commitment to our employees creates an environment that allows us to attract and retain our qualified talent, while simultaneously providing significant value to us and our stockholders by helping our employees attain their highest level of creativity and efficiency.

Demographics

As of December 31, 2025, we had 281 full-time employees, 159 of whom were located in Gabon, 44 in Egypt, 11 in Canada, 1 in Cote d'Ivoire, 1 in Equatorial Guinea, 61 in Houston and 4 corporate employees based in the United Kingdom. We also had 44 contractors in Gabon, 17 contractors in Egypt, 2 contractors in Equatorial Guinea, 2 contractors in Cote d'Ivoire, 5 contractors in the United Kingdom, 8 contractors in Canada and 24 contractors in Houston as of December 31, 2025. We are not subject to any collective bargaining agreements, although some of the national employees in Gabon are members of the National Organization of Petroleum Workers union. We believe relations with our employees are satisfactory.

Diversity and Inclusion

We value building diverse teams, embracing different perspectives and fostering an inclusive, empowering work environment for our employees. We have a long-standing commitment to equal employment opportunity as evidenced by our Equal Employment Opportunity policy. Approximately 19% of our management team are female employees, 96% of our Gabon workforce is Gabonese and 85% of our Egypt workforce is Egyptian.

Compensation and Benefits

Critical to our success is identifying, recruiting, retaining, and incentivizing our existing and future employees. We strive to attract and retain the most talented employees in the industry by offering competitive compensation and benefits. Our pay-for-performance compensation philosophy is based on rewarding each employee's individual contributions and striving to achieve equal pay for equal work regardless of gender, race or ethnicity. We use a combination of fixed and variable pay including base salary, bonus, and merit increases, which vary across the business. In addition, as part of our long-term incentive plan for executives and certain employees, we provide share-based compensation to foster our pay-for-performance culture and to attract, retain and motivate our key leaders.

As the success of our business is fundamentally connected to the well-being of our people, we offer benefits that support their physical, financial and emotional well-being. We provide our employees with access to flexible and convenient medical programs intended to meet their needs and the needs of their families. In addition to this medical coverage, we offer eligible employees dental and vision coverage, health savings and flexible spending accounts, paid time off, employee assistance programs, voluntary short-term and long-term disability insurance and term life insurance. Additionally, we offer a 401(k) Savings Plan and Deferred Compensation Plan to certain employees. Certain employees receive additional compensation for working in foreign jurisdictions.

Workplace environment is also crucial in attracting and retaining key talent. Most of our offices offer a certain level of flexibility (i.e. work from home days and/or flexible core hours) to help meet the needs of the multigenerational workforce and the needs of the business. Our benefits and compensation packages vary by location and are designed to meet or exceed local laws and to be competitive in the marketplace.

Commitment to Values and Ethics

Along with our core values, we act in accordance with our Code of Ethics, which sets forth expectations and guidance for employees to make appropriate decisions. Our Code of Ethics covers topics such as anti-corruption, discrimination, harassment, privacy, appropriate use of company assets, protecting confidential information, and reporting Code of Ethics violations. The Code of Ethics reflects our commitment to operating in a fair, honest, responsible and ethical manner and also provides direction for reporting complaints in the event of alleged violations of our policies (including through an anonymous hotline). Our executive officers and supervisors maintain "open door" policies and any form of retaliation is strictly prohibited.

Professional Development, Safety and Training

We believe that key factors in employee retention are professional development, safety and training. We have training programs across all levels to meet the needs of various roles, specialized skill sets and departments across the Company. We provide compliance education as well as general workplace safety training to our employees and offer Occupational Safety and Health Administration training to key employees. We are committed to the security and confidentiality of our employees' personal information and employ software tools and periodic employee training programs to promote security and information protection at all levels. We utilize certain employee turnover rates and productivity metrics in assessing our employee programs to ensure that they are structured to instill high levels of in-house employee tenure, low levels of voluntary turnover and the optimization of productivity and performance across our entire workforce. Additionally, we have a performance evaluation program which adopts a modern approach to valuing and strengthening individual performance through on-going interactive progress assessments related to established goals and objectives.

Communication and Engagement

We strongly believe that our success depends on employees understanding how their work contributes to our overall strategy. To this end, we communicate with our workforce through a variety of channels and encourage open and direct communication, including: (i) quarterly company-wide CEO updates; (ii) regular company-wide calls with management and (iii) frequent corporate email communications.

COMPETITION

The crude oil, natural gas and NGLs industry is highly competitive. Competition is particularly intense from other independent operators and from major crude oil, natural gas and NGLs companies with respect to acquisitions and development of desirable crude oil, natural gas and NGLs properties and licenses, and contracting for drilling equipment. There is also competition for the hiring of experienced personnel. In addition, the drilling, producing, processing and marketing of crude oil, natural gas and NGLs is affected by a number of factors beyond our control, which may delay drilling, increase prices and have other adverse effects, which cannot be accurately predicted.

Our competition for acquisitions, exploration, development and production includes the major crude oil, natural gas and NGLs companies in addition to numerous independent crude oil companies, individual proprietors, investors and others. We also compete against companies developing alternatives to petroleum-based products, including those that are developing renewable fuels. Many of these competitors have financial and technical resources and staff that are substantially larger than ours. As a result, our competitors may be able to pay more for desirable crude oil, natural gas and NGLs assets, or to evaluate, bid for and purchase a greater number of properties and licenses than our financial or personnel resources will permit. Furthermore, these companies may also be better able to withstand the financial pressures of lower commodity prices, unsuccessful wells, volatility in financial markets and generally adverse global and industry-wide economic conditions. These companies may also be better able to absorb the burdens resulting from changes in relevant laws and regulations, which may adversely affect our competitive position. Our ability to generate reserves in the future will depend on our ability to select and acquire suitable producing properties and/or develop prospects for future drilling and exploration.

INSURANCE

For protection against financial loss resulting from various operating hazards, we maintain insurance coverage, including insurance coverage for certain physical damage, blowout/control of a well, comprehensive general liability, worker's compensation and employer's liability. We maintain insurance at levels we believe to be customary in the industry to limit our financial exposure in the event of a substantial environmental claim resulting from sudden, unanticipated and accidental discharges of certain prohibited substances into the environment. Such insurance might not cover the complete claim amount and would not cover fines or penalties for a violation of environmental law. We are not fully insured against all risks associated with our business either because such insurance is unavailable or because premium costs are considered uneconomic. A material loss not fully covered by insurance could have an adverse effect on our financial position, results of operations or cash flows.

REGULATORY

General

Our operations and our ability to finance and fund our operations and growth are affected by political developments and laws and regulations in the areas in which we operate. In particular, crude oil, natural gas and NGLs production operations and economics are affected by:

- change in governments;
- civil unrest;
- price and currency controls;
- limitations on crude oil, natural gas and NGLs production;
- tax, environmental, safety and other laws relating to the petroleum industry;
- changes in laws relating to the petroleum industry;
- changes in administrative regulations and the interpretation and application of administrative rules and regulations; and
- changes in contract interpretation and policies of contract adherence.

In any country in which we may do business, the crude oil, natural gas and NGLs industry legislation and agency regulation are periodically changed, sometimes retroactively, for a variety of political, economic, environmental and other reasons, the impact of which could substantially increase our costs or affect our operations. Numerous governmental departments and agencies issue rules and regulations binding on the crude oil, natural gas and NGLs industry. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. The regulatory burden on the crude oil, natural gas and NGLs industry increases our cost of doing business and our potential for economic loss.

Gabon

The 2019 Hydrocarbons Law in Gabon contains provisions applicable to both the upstream and downstream segments. However, despite the publication of the 2019 Hydrocarbons Law, there are various issues and matters yet to be fully enacted by implementing regulations. Under the transitory provision contained in the 2019 Hydrocarbons Law, existing PSCs and other petroleum contracts, permits and authorizations remain in full force and effect until their expiration. However, any renewal or extension of those instruments is subject to the provisions of the 2019 Hydrocarbons Law, and its implementing regulations.

The 2019 Hydrocarbons Law also provides for obligations for immediate application, irrespective of the date of signature of existing PSCs or petroleum contracts and/or granting of petroleum permits and authorizations. These include (i) the requirement for foreign producers and explorers applying for an exclusive development and production authorization to conduct their operations in Gabon through a company incorporated in Gabon rather than through branches of entities incorporated in other jurisdictions; and (ii) the obligation for all companies undertaking hydrocarbon activities to domicile their site rehabilitation funds with the Bank of Central African States, which is the Central African Economic and Monetary Community ("CEMAC") or a Gabonese bank or financial institution subject to the Central African Banking Commission, which supervises banks and financial institutions licensed to operate in CEMAC countries, within one year after the entry into force of the 2019 Hydrocarbons Law.

PSCs entered into between independent contractors and the State of Gabon ("State") since the implementation of the 2019 Hydrocarbons Law must include a clause providing that participation by the State cannot exceed a 10% participating interest in the operations, to be carried by the contractor.

Under the 2019 Hydrocarbons Law, the direct or indirect assignment of a Contractor's rights or obligations to third parties (non affiliates) under the PSC is subject to approval of the Minister of Petroleum. The State and the national operator have preemption rights, which the State must exercise within 60 days and the national operator must exercise within 45 days if the State does not exercise its rights within the 60 days. The preemption right of the State and the national operator also applies in change of control situations. In February 2024, the State/national operator exercised its preemption right in a share transaction involving a number of PSCs and concessions already in effect prior to 2014.

The 2019 Hydrocarbons Law also entitles the national operator to acquire a maximum 15% stake at market value in all PSCs as of the date of signature. Further, it also provides that the State of Gabon may acquire an equity stake of up to 10%, at market value, in an operator applying for or already holding an exclusive development and production authorization.

Of critical note, the Government of Gabon announced in October 2025 its intention to replace the current 2019 Hydrocarbons Law with a new dual legal framework, comprising separate Oil and Gas Codes. This new legislation, expected to be implemented during the third quarter of 2026, aims to enhance transparency, improve fiscal terms, and provide greater legal clarity for investors in the Gabonese oil and gas sector. While existing contracts are generally expected to be honored under transitional provisions, any future renewals, extensions, or new agreements will be subject to the provisions of this forthcoming framework, which could introduce changes to current operating conditions, fiscal regimes, and regulatory requirement.

Egypt

Laws and Regulations

The Egyptian Ministry of Petroleum and Mineral Resources ("MOP") is the ministerial governmental authority responsible for the regulation and development of the oil and gas industry in Egypt. Certain government entities have been set up to help the MOP achieve its objectives.

Under the Egyptian Constitution, all oil and gas resources are under the control of the State of Egypt. Accordingly, only the State can grant rights for exploration and exploitation of oil and gas resources for interested investors. The Egyptian Constitution provides that concessions for the exploitation of such resources shall be issued by virtue of a law for a period not exceeding 30 years.

Concession Agreement

The mechanism for granting a contractor the right to carry out oil and gas exploration and development activities is the concession agreement. Concession agreements have the force and privileges of law in Egypt, meaning each agreement is an Egyptian Act of Parliament. The concession agreement overrides any contradictory Egyptian laws but not the Egyptian Constitution. In the absence of any legal rule under the relevant concession agreement, the exploration and exploitation operations will be subject to the rules of the Fuel Materials Law No. 66/1953, as amended, and its executive regulation issued by Minister of Industry Decree No. 758/1972, as amended (the "Fuel Materials Law"), and related ministerial decrees, where applicable.

Concession agreements usually follow a standard format which may be updated by the MOP and the relevant government entity from time to time, with slight variations. The commercial terms of concession agreements are open to negotiation, but each concession agreement will typically set out certain factors such as: (i) minimum work and financial commitments associated with each exploration and development program; (ii) any bonus payment(s) to be paid by the contractor to the relevant government agency upon triggering events (usually tied to certain production milestones); (iii) royalties payable to the government in cash or in kind; (iv) exploration and development periods and extensions of each; (v) rules concerning the contractor's recovery of its costs and expenses in association with exploration, development and related operations; (vi) production sharing valuations; (vii) priority right to the relevant government entity to offtake the production for domestic needs; (viii) relinquishment obligations and the associated triggering events; and (ix) requirements and procedures to convert an area to a development and to obtain a development lease, conclude sales and offtake agreement, and to dispose of the contractor's share of production.

Cost Recovery and Production Allocation

The concession agreement will set out in detail the distribution of cost recovery for the contractor, including a dedicated annex outlining the accounting procedures for treatment of costs, expenses, and taxes under the concession agreement. Typically, the contractor bears all the risks until a commercial discovery is made, and, following which, the joint operating committee ("JOC") is formed. The contractor will then be entitled to recover a certain percentage of its costs related to its previous and ongoing exploration and development activities in proportion to its working interest in the concession agreement. These costs may be recovered from the total petroleum production at a rate set out under the concession agreement on a quarterly basis. If the recoverable expenditures exceed the amount recoverable from petroleum production in any period, the unrecovered portion of the expenditures can usually be carried forward to subsequent periods. Full title to fixed and movable assets that are charged to cost recovery will usually pass from the contractor to the relevant government agency when its total costs have been recovered in accordance with the concession agreement, or at the time of relinquishment of the concession agreement with respect to all assets chargeable to the operations whether recovered or not, whichever occurs earlier.

Ownership of Assets

Under the model concession agreements, the movable and immovable assets (other than lands, which become the government entities' property as of the purchase thereof) are transferred automatically and gradually from the contractor to the government entity, as they become subject to cost recovery pursuant to the cost recovery provisions of the concession. The contractor (through the JOC) only has the right to use such assets for the purpose of petroleum operations under the concession agreement.

Termination and Revocation of Concession

The concession agreement is terminated by the lapse of its term, unless terminated prematurely. In addition, the government has the right to prematurely terminate the concession agreement in several instances set out in the concession. The government may, among other things, terminate the concession in the event of a misrepresentation by the contractor, an assignment of the contractor's rights without obtaining the required approvals, or the contractor being declared bankrupt, or committing any material breach under the concession or the Fuel Materials Law. If the government deems that one of these causes (other than force majeure events) exists, it will give the contractor 90 days' written notice to remedy and remove the cause. If, at the end of the 90-day notice period, the cause has not been remedied and removed, the concession agreement may be terminated by a presidential decree.

Cote d'Ivoire

The Petroleum Code of Cote d'Ivoire (the “Petroleum Code”) is the main legislation governing the country's oil and gas sector. Due to the general nature of the Petroleum Code, most of the specific provisions governing petroleum exploration and production are included in petroleum contracts (the “Petroleum Contracts”) which implement the principles of the Extractive Industries Transparency Initiative, a global framework for disclosure and multi-stakeholder oversight. The Uniform Acts adopted by the Organization for the Harmonisation of Business Law in Africa (the “OHADA”), of which Cote d'Ivoire is a member state, apply to companies carrying out oil and gas activities in Cote d'Ivoire, especially the OHADA Companies Act. Oil and gas activities are subject to exchange control regulations applicable within the West African Economic and Monetary Union, which is an organization of West African states established to promote economic integration among countries that share the CFA franc as a common currency, and the Economic Community of West African States, a regional group of West African nations created to promote economic integration across the region. The main regulatory oversight bodies in Cote d'Ivoire include, among others, the Ministry of Mines, Petroleum and Energy, the Direction Générale des Hydrocarbures, and Société Nationale d'Opérations Pétroliéres de la Cote d'Ivoire (PETROCI), the national oil company for oil and gas operations.

The Petroleum Code requires abandonment and rehabilitation obligations to be included in the Petroleum Contracts. In addition, the Petroleum Code provides for the obligation to include environmental provisions, in particular environmental management plans, in the Petroleum Contracts.

Canada

Pursuant to The Constitution Act, 1867 (Canada), the Canadian federal government has primary jurisdiction over interprovincial oil and gas pipelines, import and export trade in oil and gas, and offshore oil and gas exploration and production. Proposed interprovincial pipeline projects require a regulatory review by the Canada Energy Regulator under the Canadian Energy Regulator Act (Canada) to proceed. An impact assessment by the Impact Assessment Agency and a determination by the Cabinet that a pipeline project is in the public interest will also likely be required under the Impact Assessment Act (Canada)(“IAA”). On October 13, 2023, the Supreme Court of Canada found the “designated projects” component of the IAA to be largely unconstitutional, ruling that it exceeded federal legislative jurisdiction. In response, the federal government introduced and passed legislative amendments to the IAA, and one of such amendments came into force on June 20, 2024. The amended IAA aims to align the legislation with the Supreme Court’s decision by focusing on areas of clear federal jurisdiction for impact assessments.

The Alberta Energy Regulator (“AER”) is the primary regulator of resource development in Alberta. It derives its authority from the Responsible Energy Development Act (Alberta) and several related statutes. AER regulatory approval is required for all oil and natural gas projects or activities in Alberta.

In addition to conducting project approvals, the AER regulates the lifecycle of projects and performs ongoing monitoring of oil and gas projects to ensure compliance with standards and conditions set out in the licenses and approvals it issues and in the AER directives and regulations. The AER also oversees project closure obligations.

Canada also has extensive climate change regulations at both the federal and provincial level mandating greenhouse gas (“GHG”) emission reductions by oil and natural gas producers. The federal government enacted the Greenhouse Gas Pollution Pricing Act (Canada) (the “GGPPA”), which came into force on January 1, 2019. While the GGPPA previously included a fuel charge, Regulations Amending Schedule 2 to the GGPPA and the Fuel Charge Regulations (SOR/2025-107) effectively removed the fuel charge by setting applicable rates to zero, effective April 1, 2025. The federal government intends to permanently repeal the fuel charge framework under Part 1 of the GGPPA, refocusing federal carbon pollution pricing requirements on industrial emissions. One component of the GGPPA regime that remains is an emissions trading system for large industry (the Output-Based Pricing System). The GGPPA allows provinces to develop their own carbon pollution pricing systems that meet the minimum federal benchmark, failing which the federal carbon pollution pricing system applies.

Alberta’s Technology Innovation and Emissions Reduction Regulation (“TIER”) regulates emissions of heavy industry in line with federal standards. TIER was significantly amended on December 3, 2025, through Order in Council 369/2025. Key changes include the introduction of investment credits as a new compliance pathway, allowing facilities to meet up to 90% of their compliance obligation through direct investments in on-site emission reductions. The amendments also provide flexibility for smaller emitters to opt out of the TIER system for 2025. The TIER fund price was frozen at C$95/tonne in May 2025, and the regulation's automatic review and expiry dates have been extended to December 31, 2030, and December 31, 2035, respectively.

The Government of Alberta also enacted the Methane Emission Reduction Regulation (Alberta), which, in line with AER Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting and AER Directive 017: Measurement Requirements for Oil and Gas Operations, sets vent gas limits for methane per month, monitored through representative measuring data. Furthermore, the federal government announced new enhanced oil and gas methane regulations on December 16, 2025, expected to take effect in January 2028, with a target to reduce methane emissions by at least 75% below 2012 levels by 2030.

In Canada, there is a general presumption against the retroactive application of legislation absent an express statutory statement to the contrary. Significant changes to oil and gas regulations impacting existing projects are also often implemented through a prospective phase-in approach.

Equatorial Guinea

All hydrocarbons existing in Equatorial Guinea's onshore territory, as well as in its sovereign and jurisdictional waters, are Equatorial Guinea property and part of the public domain. The monetization of such hydrocarbons is to be pursued exclusively by Equatorial Guinea under its constitution, which reserves the exploitation of mineral and hydrocarbons resources exclusively to Equatorial Guinea and the public sector. However, the constitution also provides that Equatorial Guinea can delegate to, grant a concession to or associate itself with private parties for purposes of exploration and production activities in the manner and cases set forth by law.

All contracts signed with the State of Equatorial Guinea for the exploration and production of hydrocarbons have taken the form of PSCs. PSCs are subject to ratification by the President of the Republic of Equatorial Guinea and become effective only on the date the contractor is notified of presidential ratification. The powers to sign and amend PSCs and supervise their performance belong to the ministry responsible for petroleum operations (the "EG Petroleum Ministry"). In addition, the national oil company of Equatorial Guinea holds, manages and takes participations in petroleum activities on behalf of Equatorial Guinea.

The 2006 Hydrocarbons Law currently in effect in Equatorial Guinea (the "Hydrocarbons Law") incorporates the regime applicable to the exploration, appraisal, development and production of hydrocarbons, as well as the rules on their transportation, distribution, storage, preservation, decommissioning, refining, marketing, sale and other disposal. The Hydrocarbons Law contains provisions on a number of aspects concerning exploration and production operations and contracts, such as national content obligations, unitization, transfers and abandonment. The EG MHMD, which is currently the appointed EG Petroleum Ministry, has been exercising the powers contained within the Hydrocarbons Law.

Equatorial Guinea enforces national content regulations, established under its Hydrocarbons Law, with the primary goal of maximizing local participation and economic benefits from its oil and gas sector. Furthermore, they aim to increase the domiciliation of materials, equipment, and services within the country, fostering technology transfer and curbing capital outflow. Specific obligations also include the registration of all sector companies with the Ministry and the construction of prestigious office buildings by contractors after a commercial discovery.

In a move to bolster investor confidence and increase foreign investment, the Government of Equatorial Guinea passed Decree No. 100/2024 in early 2025. This decree introduces key regulations for the enforcement of judicial rulings against oil companies operating within the country, aiming to ensure procedural consistency and fairness in the execution of judgments. It reflects the government's commitment to safeguarding national interests while maintaining an attractive and predictable environment for international investors.

ENVIRONMENTAL REGULATIONS

General

Our operations are subject to various federal, state, local and international laws and regulations, including laws and regulations in Gabon, Egypt, Cote d'Ivoire, Canada (prior to the Canada Asset Divestment), Nigeria and Equatorial Guinea, governing the discharge of materials into the environment or otherwise relating to environmental protection or pollution control. The cost of compliance could be significant. While we are currently complying in all material respects with all environmental laws and regulations, failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial and damage payment obligations, or the issuance of injunctive relief (including orders to cease operations). Environmental laws and regulations are complex and have tended to become more stringent over time. We also are subject to various environmental permit requirements. Some environmental laws and regulations may impose strict liability, which could subject us to liability for conduct that was lawful at the time it occurred or joint and several liability, which could subject us to liability for conduct or conditions caused by prior operators or third parties. To the extent laws are enacted or other governmental action is taken that prohibits or restricts drilling or imposes environmental protection requirements that result in increased costs to the crude oil, natural gas and NGLs industry in general, our business and financial results could be adversely affected. Although no assurances can be made, we believe that, absent the occurrence of an extraordinary event, compliance with existing laws, rules and regulations regulating the release of materials into the environment or otherwise relating to the protection of the environment will not have a material effect upon our capital expenditures, earnings or competitive position with respect to our existing assets and operations. We cannot predict, however, what effect future environmental regulation or legislation, enforcement policies, or claims for damages to property, employees, other persons, the environment or natural resources could have on us.

In addition, a number of governmental bodies have adopted, have introduced or are contemplating regulatory changes in response to the potential impact of climate change. Legislation, increased regulation and litigation regarding climate change could impose significant costs on us, our joint venture owners, and our suppliers, including costs related to increased energy requirements, capital equipment, environmental monitoring and reporting, and other costs to comply with such regulations. For example, several nations, including Gabon, Egypt, Cote d'Ivoire, Canada and Equatorial Guinea, have signed and officially entered into an international climate change accord (the "Paris Agreement"). The Paris Agreement calls for signatory countries to set their own GHG emissions targets, make these emissions targets more stringent over time and be transparent about the GHG emissions reporting and the measures each country will use to achieve its GHG targets. A long-term goal of the Paris Agreement is to limit global temperature increase to well below two degrees Celsius from temperatures in the pre-industrial era. The Paris Agreement is effectively a successor agreement to the Kyoto Protocol treaty, an international treaty aimed at reducing emissions of GHG, to which various countries and regions are parties. On January 20, 2025, the US President signed an executive order to withdraw the United States from the Paris Agreement for the second time, with the withdrawal taking effect in January 2026. Such executive order could impact the SEC's adopted new rules requiring public companies to disclose extensive climate-related information in their SEC filings, which the SEC voluntarily stayed followed a number of petitions for review filed against the SEC that were consolidated before the US Court of Appeals for the Eighth Circuit.

The State of Gabon and the Republic of Equatorial Guinea did not sign the Global Renewables and Energy Efficiency Pledge at COP28. However, a few oil companies operating in Gabon signed the Oil and Gas Decarbonization Charter at COP28.

The United States has previously announced a target for the US to achieve a 50-52% reduction from 2005 levels in economy-wide GHG emissions by 2030. Following the Paris Agreement and its ratification in Canada, the Government of Canada also pledged to cut its emissions by 40-45% from 2005 levels by 2030. In June 2021, the Canadian federal government passed the Canadian Net-Zero Emissions Accountability Act (Canada), which provides a legal foundation and framework for Canada to achieve net-zero GHG emissions by 2050. In November 2024, the Canadian government released draft regulations aimed at capping GHG emissions from the oil and gas sector. Of note, the proposed regulations set a cap on GHG emissions within the sector, equivalent to 35% below 2019 levels by 2030 and introduce a cap-and-trade system designed to recognize better-performing companies and incentivize higher polluters to invest in cleaner production processes

Given the political significance and uncertainty around the impact of climate change and how it should be dealt with, we cannot predict how legislation and regulation, including the Paris Agreement and any related GHG emissions targets, potential prices on carbon emissions, incentives to use renewable forms of energy or other requirements, will affect our financial condition and operating performance. Apart from any new legal developments, increased awareness and any adverse publicity in the global marketplace about potential impacts on climate change by us or other companies in our industry could harm our reputation, restrict our access to capital or impact the marketability of crude oil, natural gas and NGLs. In addition, the potential physical impacts of climate change on our operations are highly uncertain and would be particular to the geographic circumstances in areas in which we operate. These may include changes in rainfall amounts, storm patterns and storm intensities, water shortages, changing sea levels, and changing temperatures. These impacts may adversely impact the cost, production, and financial performance of our operations.

In part, because they are economically developing countries, it is unclear how quickly and to what extent Gabon, Equatorial Guinea or Egypt will increase their regulation of climate change issues in the future. As of the date of this Annual Report, Equatorial Guinea has not adopted any new environmental legislation. Gabon has adopted Ordinance No. 019/2021 of September 13, 2021 on Climate Change, which ratification law has been published in the Official Gazette, with the objective of complying with the Paris Agreement (the "Ordinance on Climate Change"). The Ordinance on

Climate Change particularly aims to: (a) provide a framework for targets to be set for controlling and reducing emissions and for increasing GHG absorption in the national climate change strategy and the national plans for climate change adaptation and mitigation; (b) define and develop tools and mechanisms for climate change adaptation and mitigation; (c) provide a framework for, and implement, strategies for adaptation, monitoring mitigation and assessment, action plans, policies, programs and adaptation and mitigation measures; (d) provide a framework and take effective response for adaptation and mitigation measures to facilitate the setting of specific sustainable development, security and energy efficiency goals; (e) promote and manage sustainable development through climate change mitigation and adaptation activities; (f) establish climate change financing mechanisms; and (g) complement international instruments addressing climate change. It also sets forth climate adaptation and mitigation measures for carbon intensive operators (which include petroleum companies) such as (a) the establishment of a National Plan on the Reduction of Gas Flaring with a zero flaring objective; (b) the establishment of a GHG emissions database and quota system, (c) a carbon offset register, and (d) penalties and sanctions for not complying with such measures. Egypt ratified the United Nations Framework Convention on Climate Change (“UNFCCC”) in 1994, signed the Paris Agreement in 2016 and ratified it in 2017. Egypt is among the top affected countries by climate change. Egypt is already implementing plans pertaining to energy resources diversification and acceleration of decreased carbon emissions, in line with its “Sustainable Development Strategy: Egypt Vision 2030”, the “Integrated Sustainable Energy Strategy 2035” and its “National Climate Change Strategy 2050”. Egypt hosted the United Nations Climate Change Conference-COP27, during which the role of the oil and gas sector was the highlight of the “Decarbonization Day” thereof. Egypt submitted in June 2023 a revised Nationally Determined Contribution (“NDC”) to the United Nations Development Programme, focusing on Egypt’s commitment to reduce emissions by 65% in the oil and gas sector (1.7 Mt CO_2e) by 2030, increasing renewable energy capacities and alternative energy (including natural gas) sources to generate 42% of electricity by 2035, and increased policy actions and measures across key sectors including the oil and gas sector. In December 2023, during COP28, Egypt formally launched the first African voluntary carbon marketplace.

In addition to the ratification of the Paris Agreement, Côte d'Ivoire has implemented various climate regulations and policies to address the challenges of climate change. A Central Directorate in charge of the Fight against Climate Change was established to coordinate climate action. In 2022, Côte d'Ivoire submitted its revised NDC for 2021-2030, committing to reduce GHG emissions by 30.41% by 2030. The National Development Plan 2021-2025 includes climate change as one of its six priority areas. Other key climate-related policies include the National Gender and Climate Change Strategy, and the National REDD+ Strategy which look to develop credible carbon credit programs. Additionally, Côte d'Ivoire has joined international climate initiatives such as the Clean Development Mechanism and the Climate and Clean Air Coalition.

The Carbon Border Adjustment Mechanism (“CBAM”) is the EU’s carbon pricing tool designed to reduce carbon emissions and prevent carbon leakage by imposing a carbon price on certain imported goods. It requires importers to report embedded emissions in their products and eventually purchase CBAM certificates. Currently it applies to imports of cement, iron and steel, aluminum, fertilizers, hydrogen, and electricity with the aim to create a level playing field between EU and non-EU producers while encouraging cleaner industrial production globally. CBAM is poised to significantly reshape the global oil and gas trade landscape. As the mechanism gradually expands to encompass the oil and gas sector by 2028, with full coverage expected by 2036, industry players are bracing for substantial shifts in market dynamics. Based on WoodMac Research, CBAM's implementation could potentially increase crude and refined product prices by up to $5 per barrel, translating to approximately 30 euro cents per liter at the pump for consumers. This price adjustment is likely to alter the competitive landscape, favoring low-emission intensity crudes and potentially reshaping trade flows as producers and refiners adapt their strategies to maximize value in a carbon-constrained market.

Moreover, Gabon has recently adopted Law no. 007/2023 of November 2, 2023 on the prevention and management of disasters, which requires companies conducting activities defined as dangerous or operating at facilities that are deemed to have an impact on the environment, to obtain, as relevant, authorizations, or establish operational plans. There are no further guidelines on whether and how it will apply to the petroleum industry.

Any significant increase in the regulation or enforcement of environmental issues in any of our operating areas could have a material effect on us. Economically developing countries, in certain instances, have patterned environmental laws after those in the U.S. However, the extent that any environmental laws are enforced in economically developing countries varies significantly.

With regards to our development operations offshore West Africa, we are a member of Oil Spill Response Limited (“OSRL”), a global emergency and crude oil spill-response organization headquartered in London. OSRL has aircraft and equipment available for dispersant application or equipment transport, including various boom systems that can be used for offshore and shoreline recovery operations. In addition, VAALCO has a Tier 1 spill kit in-country for immediate deployment if required. See "*Item 1A. Risk Factors*" for further discussion on the impact of these and other regulations relating to environmental protection.

Item 1A. Risk Factors

Our business faces many risks. You should carefully consider the following risk factors in addition to the other information included in this Annual Report. If any of these risks or uncertainties actually occurs, our business, financial condition and results of operations could be materially adversely affected. Any risks discussed elsewhere in this Annual Report and in our other SEC filings could also have a material impact on our business, financial position or results of operations. Additional risks not presently known to us or that we consider immaterial based on information currently available to us may also materially adversely affect us.

Risks Relating to Our Business, Operations and Strategy

Our business requires significant capital expenditures and we may not be able to obtain needed capital or financing to fund our exploration and development activities or potential acquisitions on satisfactory terms or at all.

Our exploration and development activities, as well as our active pursuit of complementary opportunistic acquisitions, are capital intensive. To replace and grow our reserves, we must make substantial capital expenditures for the acquisition, exploitation, development, exploration and production of crude oil, natural gas and NGLs reserves. Historically, we have financed these expenditures primarily with cash from operations, debt, asset sales and private sales of equity. We are the operator of the Etame Marin block offshore Gabon, and are responsible for contracting on behalf of all the remaining parties participating in the project and rely on our joint venture owners to pay for 36.4% of the offshore Gabon budget. With respect to Block P, as the appointed technical operator, we rely on the timely payment of cash calls by our joint venture owners to pay for 46.3% of the Equatorial Guinea budget, except during any development phases where we have agreed or will agree to carry their interests. The continued economic health of our joint venture owners could be adversely affected by low crude oil prices, thereby adversely affecting their ability to make timely payment of cash calls.

If low crude oil, natural gas and NGLs prices, operating difficulties or declines in reserves result in our revenues being less than expected or limit our ability to enter into debt financing arrangements, or our joint venture owners fail to pay their share of project costs, we may be unable to obtain or expend the capital necessary to undertake or complete future drilling programs or to acquire additional reserves.

We do not currently have any commitments for future external funding for capital expenditures or acquisitions beyond cash generated from operating activities and the agreement governing our 2025 RBL Facility (the "2025 Facility Agreement") . Our ability to secure additional or replacement financing to finance expenditure beyond our current committed capital expenditure for the next 12 months may be limited. We cannot provide any assurances that such additional debt or equity financing or cash generated by operations will be available to meet our capital requirements and fund acquisitions. We may not be able to obtain debt or equity financing on terms favorable to us, or at all. Even if we succeed in selling additional equity securities to raise funds, at such time the ownership percentage of our existing stockholders would be diluted, and new investors may demand rights, preferences or privileges senior to those of existing stockholders. If we raise additional capital through debt financing, the financing may involve covenants that restrict our business activities or our ability to make future acquisitions. If cash generated by operations or cash available under any financing sources is not sufficient to meet our capital requirements beyond our current committed expenditure for the next 12 months, the failure to obtain additional financing could result in a curtailment of our operations relating to the development of our properties or prevent us from consummating acquisitions of additional reserves. Such a curtailment in operations or activities could lead to a decline in our estimated net proved reserves and would likely materially adversely affect our business, financial condition and results of operations.

Unless we are able to replace the proved reserve quantities that we have produced through acquiring or developing additional reserves, our cash flows and production will decrease over time.

Our future success depends upon our ability to find, develop or acquire additional crude oil, natural gas and NGLs reserves that are economically recoverable. In general, production from crude oil, natural gas and NGLs properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our ability to make the necessary capital investment to maintain or expand our asset base of crude oil, natural gas and NGLs reserves would be limited to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves. Except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, our estimated net proved reserves will generally decline as reserves are produced.

There can be no assurance that our development and exploration projects and acquisition activities will result in significant additional reserves or that we will have continuing success drilling productive wells at economic finding costs. The drilling of crude oil, natural gas and NGLs wells involves a high degree of risk, especially the risk of dry holes or of wells that are not sufficiently productive to provide an economic return on the capital expended to drill the wells. Additionally, seismic and other technology does not allow us to know conclusively prior to drilling a well that crude oil, natural gas or NGLs is present or economically producible. Our drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, including declines in crude oil, natural gas or NGLs prices and/or prolonged periods of historically low crude oil, natural gas and NGLs prices, weather conditions, political instability, availability of capital, economic/currency imbalances, compliance with governmental requirements, receipt of additional seismic data or the reprocessing of existing data, failure of wells drilled in similar formations, equipment failures (such as ESPs), delays in the delivery of equipment, and the availability of drilling rigs. If we are unable to increase our proved quantities, there will likely be a material impact on our cash flows, business and operations.

The Company does not always control decisions made under joint operating agreements, and the parties under such agreements may fail to meet their obligations.

The Company conducts many of its exploration and production operations through joint operating agreements with other parties under which the Company may not control decisions, either because it does not have a controlling interest or is not an operator under the agreement. Such decisions may relate to development and exploitation activities, including the timing of the capital expenditures for such activities. The success and timing of development and exploitation activities on such properties, depends upon a number of factors, including:

- the timing and amount of capital expenditures;
- the availability of suitable offshore drilling rigs, drilling equipment, support vessels, production and transportation infrastructure and qualified operating personnel;
- the operator’s expertise, financial resources and willingness to initiate exploration or development projects;
- approval of other participants in drilling wells;
- risk of a non-operator’s failure to pay its share of costs, which may require us to pay our proportionate share of the defaulting party’s share of costs;
- selection of technology;
- delays in the pace of exploratory drilling or development;
- the rate of production of the reserves; and/or
- the operator’s desire to drill more wells or build more facilities on a project inconsistent with our capital budget, whether on a cash basis or through financing, which may limit our participation in those projects or limit the percentage of our revenues from those projects.

There is also a risk that these parties may at any time have economic, business, or legal interests or goals that are inconsistent with the Company’s, and therefore, decisions may be made that the Company does not believe are in its best interest. Moreover, parties to these agreements may be unable to meet their economic or other obligations, and the Company may be required to fulfill those obligations alone. In either case, the value of the investment may be adversely affected.

The occurrence of any of the foregoing events could have a material adverse effect on our anticipated exploration and development activities.

Provisions of our agreements could discourage an acquisition of us by a third-party.

Certain provisions of our production sharing contracts, joint operating agreements and other agreements could make it more difficult or more expensive for a third-party to acquire us or our assets, or may even prevent a third-party from acquiring us or our assets. For example, some of these agreements contain restrictions on assignments of our assets, including requirements to obtain consent from applicable counterparties, preemption rights and requirements to make bonus payments. In some cases, these restrictions apply to “indirect assignments.” By discouraging an acquisition of us or our assets by a third-party, these provisions could have the effect of deterring otherwise interested third-parties from proposing or consummating these acquisitions. This could deprive the holders of our common stock of an opportunity to sell their common stock at a premium over prevailing market prices.

We have limited control over the assets we do not operate.

We have limited control over matters relating to development and exploitation activities, including the timing of and capital expenditures for such activities and compliance with environmental, safety, and other standards, of assets where we are not the operator. The operator and our fellow non-operating owners of these properties may act in ways that are not in our best interest. Additionally, we are dependent on the operator and our fellow non-operating owners of such projects to fund their contractual share of the capital expenditures of such projects. Our dependence on the operator and such parties could have a material adverse effect on our business, results of operations or financial condition.

Our offshore operations involve special risks that could adversely affect our results of operations.

Offshore operations are subject to a variety of operating risks specific to the marine environment. Our offshore production facilities are subject to hazards such as capsizing, sinking, grounding, collision and damage from severe weather conditions. The relatively deep offshore drilling that we conduct involves increased drilling risks of high pressures and mechanical difficulties, including stuck pipe, collapsed casing and separated cable. We have experienced pipeline blockages in the past and may experience additional pipeline blockages in the future. The impact that any of these risks may have upon us is increased due to the low number of producing properties we own. We could incur substantial expenses that could reduce or eliminate the funds available for exploration, development or license acquisitions, or result in loss of equipment and license interests.

Exploration and development operations offshore Africa often lack the physical and oilfield service infrastructure present in other regions. As a result, a significant amount of time may elapse between an offshore discovery and the marketing of the associated crude oil, natural gas and NGLs, increasing both the financial and operational risks involved with these operations. Offshore drilling operations generally require more time and more advanced drilling technologies, involving a higher risk of equipment failure and usually higher drilling costs. In addition, there may be production risks for which we are currently unaware. The development of new subsea infrastructure and use of floating production systems to transport crude oil from producing wells may require substantial time for installation or encounter mechanical difficulties and equipment failures that could result in loss of production, significant liabilities, cost overruns or delays.

In addition, in the event of a well control incident, containment and, potentially, clean-up activities for offshore drilling are costly. The resulting regulatory costs or penalties, and the results of third-party lawsuits, as well as associated legal and support expenses, including costs to address negative publicity, could well exceed the actual costs of containment and clean-up. As a result, a well control incident could result in substantial liabilities for us and have a significant negative impact on our earnings, cash flows, liquidity, financial position and stock price.

Acquisitions and divestitures of properties and businesses may subject us to additional risks and uncertainties, including that acquired assets may not produce as projected, may subject us to additional liabilities and may not be successfully integrated with our business. In addition, any sales or divestments of properties we make may result in certain liabilities that we are required to retain under the terms of such sales or divestments.

One of our growth strategies is to capitalize on opportunistic acquisitions of crude oil, natural gas and NGLs reserves and/or the companies that own them and other strategic transactions that fit within our overall business strategy. Any future acquisition will require an assessment of recoverable reserves, title, future crude oil, natural gas and NGLs prices, operating costs, potential environmental hazards, potential tax and employer liabilities, regulatory requirements and other liabilities and similar factors. Ordinarily, our review efforts are focused on the higher valued properties and are inherently incomplete because it generally is not feasible to review in depth every potential liability on each individual property involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and potential problems, such as ground water contamination and other environmental conditions and deficiencies in the mechanical integrity of equipment are not necessarily observable even when an inspection is undertaken. Any unidentified problems could result in material liabilities and costs that negatively impact our financial condition.

Additional potential risks related to acquisitions include, among other things:

- incorrect assumptions regarding the reserves, future production and revenues, or future operating or development costs with respect to the acquired properties, as well as future prices of crude oil, natural gas and NGLs;
- decreased liquidity as a result of using a significant portion of our cash from operations or borrowing capacity to finance acquisitions;
- significant increases in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs (including potential regulatory actions) that we are not indemnified for or that our indemnity, insurance or other protection is inadequate to protect against;
- an increase in our costs or a decrease in our revenues associated with any claims or disputes with governments or other interest owners;
- an incurrence of non-cash charges in connection with an acquisition and the potential future impairment of goodwill or intangible assets acquired in an acquisition;
- the risk that crude oil, natural gas and NGLs reserves acquired may not be of the anticipated magnitude or may not be developed as anticipated;
- difficulties in the assimilation of the assets and operations of the acquired business, especially if the assets acquired are in a new business segment or geographic area;
- the diversion of management's attention from other business concerns during the acquisition and throughout the integration process;
- losses of key employees at the acquired businesses;
- difficulties in operating a significantly larger combined organization and adding operations;
- delays in achieving the expected synergies from acquisitions;
- the failure to realize expected profitability or growth;
- the failure to realize expected synergies and cost savings; and
- challenges in coordinating or consolidating corporate and administrative functions.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and you may not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in evaluating future acquisitions. In addition, acquisitions of businesses often require the approval of certain government or regulatory agencies and such approval could contain terms, conditions, or restrictions that would be detrimental to our business after a merger.

In the case of sales or divestitures of our properties and businesses, we may become exposed to future liabilities that arise under the terms of those sales or divestitures. Under such terms, sellers typically are required to retain certain liabilities for matters with respect to their sold properties or businesses. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a sale, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations. In addition, we may be required to recognize losses in accordance with exit or disposal activities.

Our reserve information represents estimates that may turn out to be incorrect if the assumptions on which these estimates are based are inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present values of our reserves.

There are numerous uncertainties inherent in estimating quantities of proved crude oil, natural gas and NGLs reserves, including many factors beyond our control. Reserve engineering is a subjective process of estimating the underground accumulations of crude oil, natural gas and NGLs that cannot be measured in an exact manner. The estimates included in this document are based on various assumptions required by the SEC, including non-escalated prices and costs and capital expenditures subsequent to December 31, 2025, and, therefore, are inherently imprecise indications of future net revenues.

Estimates of economically recoverable crude oil, natural gas and NGLs reserves and the future net cash flows from them are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserves recovery, timing and amount of capital expenditures, marketability of crude oil, natural gas and NGLs, royalty rates, the assumed effects of regulation by governmental agencies, and future operating costs, all of which may vary materially from actual results. For those reasons, among others, estimates of the economically recoverable crude oil, natural gas and NGLs reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery, and estimates of future net revenues associated with reserves may vary and such variations may be material.

Actual future production, revenues, taxes, operating expenses, development expenditures and quantities of recoverable crude oil, natural gas and NGLs reserves may vary substantially from those assumed in the estimates. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves.

In addition, our reserves may be subject to downward or upward revision based upon production history, results of future development, availability of funds to acquire additional reserves, prevailing crude oil, natural gas and NGLs prices and other factors. Moreover, the calculation of the estimated present value of the future net revenue using a 10% discount rate as required by the SEC is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our reserves or the crude oil, natural gas and NGLs industry in general. It is also possible that reserve engineers may make different estimates of reserves and future net revenues based on the same available data.

Our reserve estimates are prepared using an average of the first-day-of-the-month prices received for crude oil, natural gas and NGLs for the preceding twelve months. Future reductions in prices, below the average calculated for 2025, would result in the estimated quantities and present values of our reserves being reduced. The forecast prices and costs assumptions assume changes in wellhead selling prices and take into account inflation with respect to future operating and capital costs.

Our proved reserves are in foreign countries and are or will be subject to service contracts, production sharing contracts and other arrangements. The quantity of crude oil, natural gas and NGLs that we will ultimately receive under these arrangements will differ based on numerous factors, including the price of crude oil, natural gas and NGLs, production rates, production costs, cost recovery provisions and local tax and royalty regimes. Changes in many of these factors could affect the estimates of proved reserves in foreign jurisdictions.

If our assumptions underlying accruals for abandonment and decommissioning costs are too low, we could be required to expend greater amounts than expected.

Our estimates of the future abandonment and remediation costs are subject to change and could vary substantially from our actual costs. Under various contracts, permits and regulations, we have material legal obligations to remove tangible equipment and restore the land or seabed at the end of operations at operational sites. Our largest asset removal obligations involve plugging and abandonment of wells, removal and disposal of offshore oil and gas platforms around the world, as well as oil and gas production facilities. Estimating future asset removal costs requires significant judgment. Most of these removal obligations are many years, or decades, in the future and the contracts and regulations often have vague descriptions of what removal practices and criteria must be met when the removal event actually occurs. The carrying value of our asset retirement obligation estimate is sensitive to inputs such as asset removal technologies and costs, regulatory and other compliance considerations, expenditure timing, and other inputs into valuation of the obligation, including discount and inflation rates, which are all subject to change between the time of initial recognition of the liability and future settlement of our obligation.

If we are required to expend greater amounts than expected on abandoning or decommissioning costs or on future abandonment funding, this could materially affect our revenues and financial performance.

We could lose our interest in Block P in Equatorial Guinea if we do not meet our commitments under the production sharing contract.

Our Block P production sharing contract provides for a development and production period of 25 years from the first oil production. We and our Block P joint venture owners are evaluating the timing and budgeting for development and exploration activities in the block. There can be no certainty that any such transaction will be completed or that we will be able to commence drilling operations in Block P. If the joint venture owners of Block P fail to meet the commitments under the production sharing contract amendment, our capitalized costs of $10 million associated with Block P interest would be impaired.

The FPSO in Côte d'Ivoire ceased hydrocarbon production on January 31, 2025 for scheduled maintenance. Our results will be adversely affected until the FPSO is returned to service which may be a time later than we expect.

As an offshore asset, we, along with the operator and contractors of the Block CI-40 PSC, depend on the FPSO to store the crude oil produced prior to sale to customers. As part of the planned dry dock refurbishment, the Baobab FPSO ceased hydrocarbon production on January 31, 2025, with the final crude oil lifting in February 2025. The vessel departed from the field in late March 2025 and arrived at the shipyard in Dubai in May 2025. Although, the refurbishment work was completed in February 2026 and the Baobab FPSO has commenced its mobilization back to Cote d'Ivoire, there can be no assurance that the FPSO will return to service in the expected timeframe or that the costs of returning it to service will not be more than expected, and in either such case our results would be adversely affected. In addition, there can be no assurance that wells that are currently shut in will be returned to production on a timely basis, if at all, or at historical or anticipated production levels.

Commodity derivative transactions that we enter into may fail to protect us from declines in commodity prices and could result in financial losses or reduce our income.

In order to reduce the impact of commodity price uncertainty and increase cash flow predictability relating to the marketing of our crude oil, natural gas and NGLs we have entered into and may continue to enter into derivative arrangements with respect to a portion of our expected production in order to hedge against potential commodity price declines. In addition, under the 2025 RBL Facility agreement, if the aggregate borrowings under the 2025 RBL Facility exceeds 35% of the lower of (a) the available total commitments and (b) the applicable borrowing base amount, we are also required to enter into commodity price hedge positions covering certain volumes of anticipated future production set out in the banking case.

Our derivative contracts typically consist of a series of commodity swap contracts, such as puts, collars and fixed price swaps, and are limited in duration.

The hedge counterparty will be obligated to make payments to us to the extent that the floating (market) price is below an agreed fixed (strike) price. However, hedging agreements expose us to risk of financial loss if the counterparty to a hedging contract defaults on its contract obligations. Disruptions in the market could also lead to sudden changes in the liquidity of the counterparties to our hedge transactions, which in turn limits our ability to perform under their hedging contracts with us. Even if we accurately predict sudden changes, our ability to negate the related risk may be limited depending upon market conditions. If the creditworthiness of our counterparties deteriorates and results in their non-performance, we could incur a significant loss.

Derivative arrangements also expose us to the risk of financial loss in some circumstances, including when production is less than the volume covered by the derivative instruments or when there is an increase in the differential between the underlying price and actual prices received pursuant to the derivative instrument. In addition, certain types of derivative arrangements may limit the benefit that we could receive from increases in the prices for crude oil, natural gas and NGLs, and may expose us to cash margin requirements.

We are exposed to the credit risks of the third parties with whom we contract.

We are exposed to third-party credit risk through our contractual arrangements with government entities party to our PSCs, our current or future joint venture owners, marketers of our petroleum and natural gas production, purchasers of our oil, natural gas and NGLs products and other parties. In addition, we are exposed to third-party credit risk from operators of properties in which we have a working interest or royalty interest. In the event such entities fail to meet their contractual obligations to us, such failures may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry generally and among our joint venture owners may affect a joint venture owner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until we find a suitable alternative partner. To the extent that any of such third parties go bankrupt, become insolvent, or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in our inability to collect all or a portion of any money owing from such parties. Any of these factors could materially adversely affect our financial and operational results.

Our ability to collect payments from the sale of crude oil, natural gas and NGLs from our customers depends on the payment ability of our customer base, which may include a small number of significant customers. For example, our revenue concentration by customer for each of the Gabon, Egypt, and Cote d'Ivoire operating segments for the year ended December 31, 2025, was with a single respective significant customer. If our significant customers fail to pay for any reason, we could experience a material loss. In addition, if our significant customers cease to purchase or reduce the volume they purchase of our crude oil, natural gas or NGLs, the loss or reduction could have a detrimental effect on our production volumes and may cause a temporary interruption in sales of, or a lower price for, our crude oil, natural gas and NGLs.

In addition, we are and may in the future be exposed to third-party credit risk through our contractual arrangements with governmental entities in countries where we operate. Significant changes in the crude oil industry, including fluctuations in commodity prices and economic conditions, environmental regulations, government policy, royalty rates and other geopolitical factors, could adversely affect our ability to realize the full value of our accounts receivable from government entities in countries where we operate. Historically, we have had significant account receivables outstanding from governmental entities in countries where we operate. For example, while EGPC has made regular payments of these amounts, the timing of these payments have historically been longer than the normal industry standard. In addition, EGPC has at times faced difficulties in accessing foreign exchange markets for the purpose of obtaining U.S. dollars in exchange for Egyptian pounds. In the event the governments of the countries where we operate fail to meet their respective obligations or we are forced to accept payment in foreign currencies, such failures could materially adversely affect our financial and operational results.

We are also exposed to third-party credit risk through our banking relationships in the jurisdictions in which we operate. In 2023, macroeconomic conditions caused turmoil in the banking sector in the United States and elsewhere. We were not impacted by such turmoil. However, if similar conditions arise in the banking sector again and if any of the banks in which we keep our deposits is affected by such turmoil, we could be materially and adversely affected.

Our business could be materially and adversely affected by security threats, including cybersecurity threats, and other disruptions.

As a crude oil, natural gas and NGLs producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. The potential for such security threats has subjected our operations to increased risks that could have a material adverse effect on our business. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs. Costs for insurance may also increase as a result of security threats, and some insurance coverage may become more difficult to obtain, if available at all. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of sensitive information, critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations and cash flows.

Cybersecurity attacks in particular are becoming more sophisticated, and geopolitical tensions or conflicts, such as Russia's invasion of Ukraine or the ongoing conflicts in the Middle East, may further heighten the risk of such attacks. We rely extensively on information technology systems, including internet sites, computer software, data hosting facilities and other hardware and platforms, some of which are hosted by third parties, to assist in conducting our business. Our technologies systems and networks, and those of our business associates may become the target of cybersecurity attacks, including without limitation malicious software, attempts to gain unauthorized access to data and systems, and other electronic security breaches that could lead to disruptions in critical systems and materially and adversely affect our business in a variety of ways, including the following:

- unauthorized access to and release of seismic data, reserves information, strategic information or other sensitive or proprietary information, which could have a material adverse effect on our ability to compete for crude oil, natural gas and NGLs resources;
- data corruption, communication interruption, or other operational disruption during drilling activities could result in failure to reach the intended target or a drilling incident;

- unauthorized access to and release of personal identifying information of employees and vendors, which could expose us to allegations that we did not sufficiently protect that information and potential liabilities under domestic and international data and privacy laws;
- a cybersecurity attack on a vendor or service provider, which could result in supply chain disruptions that could delay or halt operations;
- a cybersecurity attack on third-party gathering, transportation, processing, fractionation, refining or export facilities, which could delay or prevent us from transporting and marketing our production, resulting in a loss of revenues;
- a cybersecurity attack involving commodities exchanges or financial institutions could slow or halt commodities trading, thus preventing us from engaging in hedging activities, resulting in a loss of revenues; and
- business interruptions, including use of social engineering schemes and/or ransomware, could result in expensive remediation efforts, distraction of management, damage to our reputation, or a negative impact on the price of our common stock.

To protect against such attempts of unauthorized access or attack, we have implemented multiple layers of cybersecurity protection, infrastructure protection technologies, disaster recovery plans and employee training. While we have invested significant amounts in the protection of our technology systems and maintain what we believe are adequate security controls over sensitive data, there can be no guarantee such plans will be effective.

Any cyber incident could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability. Additionally, certain cyber incidents, such as surveillance, may remain undetected for an extended period.

Current and future geopolitical events outside of our control could adversely impact our business, results of operations, cash flows, financial condition and liquidity.

We face risks related to geopolitical events, international hostility, epidemics, outbreaks and other macroeconomic events that are outside of our control. The occurrence of certain geopolitical events, including those arising from terrorist activity, international hostility, public health crises, and the economic impact of global trade tensions and the imposition of tariffs, could significantly disrupt our business and operational plans and adversely affect our results of operations, cash flows, financial condition and liquidity. For instance, the ongoing conflicts in the Middle East, including the United States-Israel-Iran war and between Russia and Ukraine have and may continue to cause geopolitical instability, and adversely impact the global economy, supply chains and specific markets and industries. Although we are not able to enumerate all potential risks to our business resulting from these and other similar events, we believe that such risks include, but are not limited to, the following:

- disruption to our supply chain for materials essential to our business, including restrictions on importing and exporting products;
- customers, suppliers and other third parties arguing that their non-performance under our contracts with them is permitted as a result of force majeure or other reasons;
- cybersecurity attacks, particularly as digital technologies may become more vulnerable and experience a higher rate of cyberattacks in the current environment of remote connectivity;
- any reductions of our workforce to adjust to market conditions, including severance payments, retention issues, and possible inability to hire employees when market conditions improve;
- logistical challenges, including those resulting from border closures and travel restrictions, as well as the possibility that our ability to continue production may be interrupted, limited or curtailed if workers and/or materials are unable to reach our offshore platforms, our FPSO vessel and our FSO charter vessel or our counterparties are unable to lift crude oil from our FPSO vessel or our FSO charter vessel;
- economic, political and regulatory conditions domestically and internationally, including imposition of tariffs or other tax incentives or disincentives;
- we may be materially adversely affected by the effects of sanctions and other penalties imposed on Russia by the U.S., the European Union and other countries; and
- we may experience a structural shift in the global economy and our demand for crude oil, natural gas and NGLs as a result of changes in the way people work, travel and interact, or in connection with a global recession or depression.

In 2025 and continuing into 2026, the current U.S. presidential administration has implemented wide-ranging policy changes and issued numerous executive actions on topics including international trade, energy resources, corporate taxes, global climate change initiatives, employment practices, corporate compliance programs and environmental regulations, among other matters. In addition, the administration has continued to pursue structural changes to the executive branch of the federal government, including significant reductions in the federal workforce and reorganization of certain regulatory agencies. Ongoing legal challenges to many of these policy changes and executive actions remain unresolved, contributing to increased regulatory uncertainty.

In addition, any disruption in the operations of the U.S. federal government, including as a result of any future temporary or prolonged shutdowns resulting from the failure of Congress to enact appropriations bills, raise the federal debt ceiling or otherwise, could adversely affect our business, operations and financial condition. Recently, beginning on October 1, 2025 through November 12, 2025, the U.S. federal government shut down, during which time certain regulatory agencies, such as the SEC, furloughed large numbers of employees and stopped routine activities and operations. Additionally, on October 10, 2025, the U.S. federal government implemented substantial layoffs and workforce reductions in connection with the federal government shutdown, which resulted in the suspension or delay of various government-funded programs. Furthermore, the recent federal government shutdown resulted in reduced availability of government services, and the suspension or delay of activities by key agencies that regulate or otherwise interact with our business, including the SEC. As a result, review and approval of our filings, applications, and submissions could be delayed, and we may be unable to access or rely upon certain government data or systems. Any U.S. federal government shutdown or prolonged budget negotiation uncertainty may further adversely affect the broader U.S. economy, investor confidence, and capital markets. Such conditions could negatively impact the liquidity or trading volume of our securities, which in turn could have a material adverse effect on our business, results of operations, and stock price.

Furthermore, geopolitical events, including the recent developments in Venezuela and Iran and changing U.S. foreign policy priorities, have heightened volatility in the regulatory environment affecting our industry. We cannot predict how these policy changes, executive actions, and geopolitical events will be implemented or interpreted or the impact of a possible U.S. federal government shutdown or prolonged budget negotiation, or the ultimate effect they will have on our business, financial condition, and results of operations.

We cannot reasonably estimate the period of time that these conditions will persist; the full extent of the impact they will have on our business, results of operations, cash flows, financial condition and liquidity; or the pace or extent of any subsequent recovery.

Production cuts mandated by the government of Gabon, a member of OPEC, could adversely affect our revenues, cash flow and results of operations.

Historically and from time to time, members of OPEC and other leading allied producing countries (collectively, "OPEC+") have entered into agreements to reduce worldwide production of crude oil to reduce the gap between excess supply and demand in an effort to stabilize the international oil market. As a member of OPEC+, Gabon may take measures to comply with such OPEC+ production quota agreements. As a result, the Minister of Hydrocarbons may request us to limit our production for a period of time in compliance with the OPEC+ mandate.

The ability of the OPEC+ to agree on and to maintain crude oil price and production controls has also had, and is likely to continue to have, a significant impact on the market prices of crude oil.

We have not received any mandate to reduce current oil production from the Etame Marin block as a result of an OPEC+ initiative and currently, our production is not impacted by OPEC+ curtailments. However, any future reduction in our crude oil production or export activities for a substantial period could materially and adversely affect our revenues, cash flows and results of operations. Gabon remains a member of OPEC+.

We have less control over our investments in foreign properties than we would have over our domestic investments.

Our exploration, development and production activities are subject to various political, economic and other uncertainties, including but not limited to changes, sometimes frequent or marked, in energy policies or the personnel administering them, expropriation of property, cancellation or modification of contract rights, changes in laws and policies governing operations of foreign-based companies, unilateral renegotiation of contracts by governmental entities, uncertainties as to whether laws and regulations will be applicable in any particular circumstance, uncertainty as to whether we will be able to demonstrate to the satisfaction of the applicable governing authorities compliance with governmental or contractual requirements, redefinition of international boundaries or boundary disputes, foreign exchange restrictions, currency fluctuations, foreign currency availability, royalty and tax increases, changes to tax legislation or the imposition of new taxes, the imposition of production bonuses or other charges and other risks arising out of governmental sovereignty over the areas in which our operations are conducted.

Our operations require, and any future opportunistic acquisitions may require, protracted negotiations with host governments, local governments and communities, local competent authorities, national oil companies, and third parties. Host governments may also conduct audits of our operations, the results of which may have a significant negative impact on our reported earnings or cash flows. Host governments may seek to participate in oil, natural gas or NGLs projects in a manner that could be dilutive to our interests. Host governments may also require us to hire a specified percentage of local citizens in our operations. In addition, if a dispute arises with respect to our foreign operations, we may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons, especially foreign crude oil ministries and national oil companies, to the jurisdiction of the U.S.

Private ownership of crude oil reserves under crude oil leases in the U.S. differs distinctly from our rights in foreign reserves where the state generally retains ownership of the minerals and, in many cases participates in, the exploration and production of hydrocarbon reserves. In the foreign countries in which we may do business, the state generally retains ownership of the minerals and consequently retains control of, and in many cases participates in, the exploration and production of hydrocarbon reserves. Accordingly, operations outside the U.S. may be materially affected by host governments.

Any of the factors detailed above or similar factors could have a material adverse effect on our business, results of operations or financial condition. If our operations are disrupted and/or the economic integrity of our projects are threatened for unexpected reasons, our business may be harmed. Prolonged problems may threaten the commercial viability of our operations.

Our operations may be adversely affected by political and economic circumstances in the countries in which we operate.

Our operations are subject to risks of loss due to civil strife, acts of war, acts of terrorism, piracy, disease, guerrilla activities, insurrection, military activities and other political risks, including tension and confrontations among political parties, that may result in:

- volatility in global crude oil prices, which could negatively impact the global economy, resulting in slower economic growth rates, which could reduce demand for our products;
- negative impact on the world crude oil supply if infrastructure or transportation are disrupted, leading to further commodity price volatility;
- difficulty in attracting and retaining qualified personnel to work in areas with potential for conflict;
- the inability of our personnel or supplies to enter or exit the countries where we are conducting operations;
- disruption of our operations due to evacuation of personnel;
- the inability to deliver our production due to disruption or closing of transportation routes;
- a reduced ability to export our production due to efforts of countries to conserve domestic resources;
- damage to or destruction of our wells, production facilities, receiving terminals or other operating assets;
- the incurrence of significant costs for security personnel and systems;
- damage to or destruction of property belonging to our commodity purchasers leading to interruption of deliveries, claims of force majeure, and/or termination of commodity sales contracts, resulting in a reduction in our revenues;
- the inability of our service and equipment providers to deliver items necessary for us to conduct our operations resulting in a halt or delay in our planned exploration activities, delayed development of major projects, or shut-in of producing fields;
- a lack of availability of drilling rig, oilfield equipment or services if third party providers decide to exit the region;
- the imposition of U.S. government or international sanctions that limit our ability to conduct our business;
- a shutdown of a financial system, communications network, or power grid causing a disruption to our business activities; and

- a capital market reassessment of risk and reduction of available capital, making it more difficult for us and our joint owners to obtain financing for potential development projects.

Some of these risks may be higher in the developing countries in which we conduct our activities, namely, Gabon, Egypt, Cote d'Ivoire, Nigeria and Equatorial Guinea.

While we monitor the economic and political environments of the countries in which we operate, loss of property and/or interruption of our business plans resulting from civil or political unrest could have a significant negative impact on our earnings and cash flow. In addition, losses caused by these disruptions may not be covered by insurance, or even if they are covered by insurance, we may not have enough insurance to cover all of these losses. If any violent action causes us to become involved in a dispute, we may be subject to the exclusive jurisdiction of courts outside the U.S. or may not be successful in subjecting non-U.S. persons to the jurisdiction of courts in the U.S. or international arbitration, which could adversely affect the outcome of such dispute.

Inflation could adversely impact our ability to control costs, including operating expenses and capital costs.

The U.S. inflation rate has fluctuated throughout 2024 and 2025, and it remains close to the historic levels over the past several decades. Although the current outlook is uncertain, heightened inflation may persist in the near to medium-term, particularly in the U.S., with the possibility that monetary policy may tighten in response. In addition, global and industry-wide supply chain disruptions have resulted in shortages in labor, materials and services. Such shortages have resulted in inflationary cost increases for labor, materials and services and could continue to cause costs to increase, or cause a scarcity of certain products and raw materials. To the extent inflation remains elevated, we may experience further cost increases for our operations, including oilfield services and equipment as a result of increasing prices of oil, natural gas and NGLs, increased drilling activity in our areas of operations, and increased labor costs. An increase in the prices of oil, natural gas and NGLs may cause the costs of materials and services we use to rise. We cannot predict any future trends in the rate of inflation, and a significant increase in inflation, to the extent we are unable to recover higher costs through higher commodity prices and revenues, could negatively impact our business, financial condition and results of operation.

Our results of operations, financial condition and cash flows could be adversely affected by changes in currency exchange rates.

We are exposed to foreign currency risk from our foreign operations. While crude oil sales are denominated in U.S. dollars, portions of our costs in Gabon and Cote d'Ivoire are denominated in the local currency. A weakening U.S. dollar will have the effect of increasing costs, while a strengthening U.S. dollar will have the effect of reducing operating costs. The Gabonese and Ivorian local currency is tied to the Euro. The exchange rate between the Euro and the U.S. dollar has fluctuated widely in recent years in response to international political conditions, general economic conditions, the European sovereign debt crisis and other factors beyond our control. Our financial statements, presented in U.S. dollars, may be affected by foreign currency fluctuations through both translation risk and transaction risk. In addition, currency devaluation can result in a loss to us for any deposits of that currency, such as our deposits in the Etame PSC abandonment account, which have been converted from U.S. dollars to the Gabonese local currency.

We are also exposed to foreign currency exchange risk related to certain cash, accounts receivable, lease obligations and accounts payable and accrued liabilities denominated in Canadian dollars, and on cash balances denominated in Egyptian pounds. Some collections of our accounts receivable from the Egyptian Government are received in Egyptian pounds, and while we are generally able to spend the Egyptian pounds received on accounts payable denominated in Egyptian pounds, there remains foreign currency exchange risk exposure on Egyptian pound cash balances.

We currently do not utilize derivative instruments to manage these foreign currency risks. As a result, our consolidated earnings and cash flows may be impacted by movements in the exchange rates.

We operate in international jurisdictions, and we could be adversely affected by violations of the U.S. Foreign Corrupt Practices Act and similar worldwide anti-corruption laws.

We are subject to the provisions of the U.S. Foreign Corrupt Practices Act, the UK Bribery Act and other similar laws. The foregoing laws prohibit companies and their intermediaries from making improper payments to officials for the purpose of obtaining or retaining business. In addition, such laws require the maintenance of records relating to transactions and an adequate system of internal controls over accounting. There can be no assurance that our internal control policies and procedures, compliance mechanisms or monitoring programs will protect us from recklessness, fraudulent behavior, dishonesty or other inappropriate acts or adequately prevent or detect possible violations under applicable anti-bribery and anti-corruption legislation.

Our failure to comply with anti-bribery and anti-corruption legislation, or investigations by governmental authorities, could result in severe criminal or civil sanctions and may subject us to other liabilities, including fines, prosecution, potential debarment from public procurement and reputational damage, all of which could have a material adverse effect on our business, results of operations and financial condition.

Our business could suffer if we lose the services of, or fail to attract, key personnel.

We are highly dependent upon the efforts of our senior management and other key employees. The loss of the services of our Chief Executive Officer, Chief Operating Officer or Chief Financial Officer, as well as any loss of the services of one or more other members of our senior management, could delay or prevent the achievement of our objectives. We do not maintain any “key-man” insurance policies on any of our senior management, and do not intend to obtain such insurance. In addition, due to the specialized nature of our business, we are highly dependent upon our ability to attract and retain qualified personnel with extensive experience and expertise in evaluating and analyzing drilling prospects and producing crude oil, natural gas and NGLs from proved properties and maximizing production from crude oil, natural gas and NGLs properties. There is competition for qualified personnel in the areas of our activities, and we may be unsuccessful in attracting and retaining these personnel.

We are subject to relinquishment obligations under certain of our title documents.

We are subject to relinquishment obligations under certain of our title documents that oblige us to relinquish certain proportions of our concession lease and license areas and thereby reduce our acreage. Additionally, we may be unable to drill all of our prospects or satisfy our minimum work commitments prior to relinquishment and may be unable to meet our obligations under the title documents. Failure to meet such obligations could result in concessions, leases and licenses being suspended, revoked or terminated which could have a material adverse effect on our business.

Our results of operations, financial condition and cash flows could be adversely affected by changes in currency regulations.

From time to time, emerging market countries such as those in which we operate adopt measures to restrict the availability of the local currency or the repatriation of capital across borders. These measures are imposed by governments or central banks, in some cases during times of economic instability, to prevent the removal of capital or the sudden devaluation of local currencies or to maintain in-country foreign currency reserves. In addition, many emerging markets countries require consents or reporting processes before local currency earnings can be converted into U.S. dollars or other currencies and/or such earnings can be repatriated or otherwise transferred outside of the operating jurisdiction. These measures may have a number of negative effects on us, including the reduction of the immediately available capital that we could otherwise deploy for investment opportunities or the payment of expenses. In addition, measures that restrict the availability of the local currency or impose a requirement to operate in the local currency may create other practical difficulties for us.

In December 2021 and during 2022, the Bank of Central African States (“BEAC”), which is the central bank for the CEMAC, passed new regulations and instructions for the CEMAC FX regulations, which were introduced in 2018, that only apply to the extractive industry. The intent of the new regulations is to ensure the application of the FX regulations as of January 1, 2022, without impeding the operations of the extractive industry. Due to the lack of necessary banking infrastructure and preparedness by the banking sector and the various government agencies to apply the new regulations, it is foreseeable that we will run the risk of seeing delays in paying our vendors and domiciliation of goods and services into the CEMAC region throughout 2026 and beyond.

As part of securing the first of two five-year extensions to the Etame PSC in 2016, we agreed to a cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin block. On February 28, 2019, in accordance with certain foreign currency regulatory requirements, the Gabonese branch of the international commercial bank holding the abandonment funds in a U.S. dollar-denominated account transferred the funds to the Central Bank for CEMAC and later converted, at the request of BEAC, the funds in U.S. dollars to franc CFA, the currency of the CEMAC, of which Gabon is one of the six member states. The Etame PSC provides that these payments must be denominated in U.S. dollars. After continued discussions with CEMAC, they agreed to the return of the USD funds and on January 12, 2023, the abandonment funds were returned to the USD account of the Gabonese branch of the international commercial bank. We were allowed to re-establish a USD denominated account and made whole for the original USD amount. Pursuant to Amendment No. 5 of the Etame PSC, we are working with Directorate of Hydrocarbons in Gabon on establishing a payment schedule to resume funding of the abandonment fund in compliance with the Etame PSC.

Our results of operations, financial condition and cash flows could be adversely affected by changes to interest rates.

As of December 31, 2025, we had $190.0 million of aggregate facility commitments, $130.0 million of available borrowing capacity and $60.0 million of outstanding borrowings under the 2025 RBL Facility. An increase in interest rates could result in a significant increase in the amount we pay to service any subsequently drawn, and any future other debt taken out by us, resulting in a reduced amount available to fund our exploration and development activities and, if applicable, the cash available for dividends. Such an increase could also negatively impact the market price of the shares of common stock.

The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced.

At December 31, 2025, approximately 59% of our total estimated proved reserves were undeveloped reserves. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling. Our reserves data assumes that we can and will make these expenditures and conduct these operations successfully. These assumptions, however, may not prove correct. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices will reduce the value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. If we choose not to spend the capital to develop these reserves, or if we are not otherwise able to successfully develop these reserves, we will be required to write-off these reserves. In addition, under the SEC's reserve rules, because proved undeveloped reserves may be recognized only if they relate to wells planned to be drilled within five years of the date of their initial recognition, we may be required to write off any proved undeveloped reserves that are not developed within this five-year time frame.

Risks Relating to Our Industry

Crude oil, natural gas and NGLs prices are highly volatile and a depressed price regime, if prolonged, may negatively affect our financial results.

Our revenues, cash flow, profitability, crude oil, natural gas and NGLs reserves value and future rate of growth are substantially dependent upon prevailing prices for crude oil, natural gas and NGLs. Our ability to enter into debt financing arrangements and to obtain additional capital on reasonable terms, or at all, is substantially dependent on crude oil, natural gas and NGLs prices.

World-wide crude oil, natural gas and NGLs prices and markets have been volatile and may continue to be volatile in the future. Prices for crude oil, natural gas and NGLs are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for crude oil, natural gas and NGLs, market uncertainty and a variety of additional factors that are beyond our control. These factors include, but are not limited to, increases in supplies from U.S. shale production; international political conditions, including war, uprisings, terrorism and political unrest in the Middle East and Africa; slowdowns to the global supply chain; the domestic and foreign supply of crude oil, natural gas and NGLs; actions by OPEC+ member countries and other state-controlled oil companies to agree upon and maintain crude oil price and production controls; the level of consumer demand that is impacted by economic growth rates; weather conditions; domestic and foreign governmental regulations and taxes; the price and availability of alternative fuels; technological advances affecting energy consumption; the health of international economic and credit markets; and changes in the level of demand resulting from global or national health epidemics and concerns. In addition, various factors including the effect of federal, state and foreign regulation of production and transportation, general economic conditions, changes in supply due to drilling by other producers and changes in demand may adversely affect our ability to market our crude oil, natural gas and NGLs production.

In a period of depressed or declining crude oil, natural gas and NGLs prices, we are subject to numerous risks, including but not limited to the following:

- our revenues, cash flows and profitability may decline substantially, which could also indirectly impact expected production by reducing the amount of funds available to engage in exploration, drilling and production;

- third-party confidence in our commercial or financial ability to explore and produce crude oil, natural gas and NGLs could erode, which could impact our ability to execute on our business strategy;
- our suppliers, hedge counterparties (if any), vendors and service providers could renegotiate the terms of our arrangements, terminate their relationship with us or require financial assurances from us;
- we may take measures to preserve liquidity, such us our decision to cease or defer discretionary capital expenditures during such periods of depressed or declining oil prices; and
- it may become more difficult to retain, attract or replace key employees.

The occurrence of certain of these events may have a material adverse effect on our business, results of operations and financial condition.

If crude oil, natural gas or NGLs prices decline, we expect that the estimated quantities and present values of our reserves will be reduced, which may necessitate write-downs. Any future write-downs or impairments could have a material adverse impact on our results of operations. A material decline in prices could also result in a reduction of our net production revenue. Any substantial and extended decline in the price of oil, natural gas and NGLs would have an adverse effect on the carrying value of our reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on our business, financial condition, results of operations and prospects. Volatile oil, natural gas and NGLs prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil, natural gas and NGLs producing properties, as buyers and sellers have difficulty agreeing on such values. Price volatility also makes it difficult to budget for, and project the return on, acquisitions and development and exploitation projects.

Exploring for, developing, or acquiring reserves is capital intensive and uncertain.

We may not be able to economically find, develop, or acquire additional reserves, or may not be able to make the necessary capital investments to develop our reserves, if our cash flows from operations decline or external sources of capital become limited or unavailable. Drilling activities are subject to many risks, including the risk that no commercially productive reservoirs will be encountered. There can be no assurance that new wells that we drill will be productive or that we will recover all or any portion of our investment. Drilling for crude oil, natural gas and NGLs may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. The cost of drilling, completing and operating wells is often uncertain and cost overruns are common. In particular, offshore drilling and development operations require highly capital-intensive techniques.

Our drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, many of which are beyond our control, including weather conditions, equipment failures or accidents, elevated pressure or irregularities in geologic formations, compliance with governmental requirements and shortages or delays in the delivery of or increased costs for equipment and services. If we are unable to continue drilling operations and we do not replace the reserves we produce or acquire additional reserves, our reserves, revenues and cash flow will decrease over time, which could have a material effect on our ability to continue as a going concern.

Our costs could escalate and become uncompetitive due to supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, and additional government intervention through stimulus spending or additional regulations. Our inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on our financial performance and cash flows.

Competitive industry conditions may negatively affect our ability to conduct operations.

The crude oil, natural gas, and NGLs industry is intensely competitive. Our competitors include major integrated oil companies and substantial independent energy companies, many of which possess greater financial, technological, personnel and other resources than we do.

We may be outbid by our competitors in our attempts to acquire exploration and production rights in crude oil, natural gas and NGLs properties. These properties include exploration prospects as well as properties with proved reserves. Our competitors may also use superior technology that we may be unable to afford or that would require costly investment in order to compete. There is also competition for contracting for drilling equipment and the hiring of experienced personnel. Factors that affect our ability to compete in the marketplace include, among other things:

- our access to the capital necessary to drill wells and acquire properties;
- our ability to acquire and analyze seismic, geological and other information relating to a property;
- our ability to retain and hire experienced personnel, especially for our engineering, geoscience and accounting departments; and
- the location of, and our ability to access, platforms, pipelines and other facilities used to produce and transport crude oil, natural gas and NGLs production.

In addition, competition due to advances in renewable fuels may also lessen the demand for our products and negatively impact our profitability.

Alternatives to petroleum-based products and production methods are continually under development. For example, a number of automotive, industrial and power generation manufacturers are developing alternative clean power systems using fuel cells or clean-burning gaseous fuels that may address increasing worldwide energy costs, the long-term availability of petroleum reserves and environmental concerns, which if successful could lower the demand for crude oil, natural gas and NGLs. If these non-petroleum based products and crude oil alternatives continue to expand and gain broad acceptance such that the overall demand for crude oil, natural gas and NGLs is decreased, it could have an adverse effect on our operations and the value of our assets.

Weather, unexpected subsurface conditions and other unforeseen operating hazards may adversely impact our crude oil, natural gas and NGLs activities.

The crude oil, natural gas and NGLs business involves a variety of operating risks, including fire, explosions, blow-outs, pipe failure, casing collapse, abnormally pressured formations; and environmental hazards such as crude oil spills, natural gas leaks, ruptures and discharges of toxic gases, underground migration, and surface spills or mishandling of well fluids, including chemical additives. The occurrence of any of these or other related events could result in substantial losses due to injury and loss of life, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations.

Climate change could have an effect on the severity of weather (including hurricanes, floods and wildfires), sea levels, the arability of farmland, and water availability and quality. If such effects were to occur, our exploration and production operations may be adversely affected. Potential adverse effects could include damages to our facilities, disruption of our production activities, less efficient or non-routine operating practices necessitated by climate effects or increased costs for insurance coverages in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship.

We maintain insurance against some, but not all, potential risks; however, there can be no assurance that such insurance will be adequate to cover any losses or exposure for liability. The occurrence of a significant unfavorable event not fully covered by insurance could have a material adverse effect on our financial condition, results of operations and cash flows. Furthermore, we cannot predict whether insurance will continue to be available to us at a reasonable cost or at all.

An increased societal and governmental focus on ESG matters, including climate change issues, may adversely impact our business, hinder access to investors and financing, and decrease demand for our product.

Heightened expectations for companies to address ESG matters, including climate change, social license to operate, human rights, and governance, have a myriad of potential impacts on our business. Investors, lenders, and other stakeholders are increasingly factoring these issues into investment, financing, and business decisions, often relying on ESG ratings from third-party agencies. Unfavorable ESG ratings, coupled with growing activism around fossil fuels, could dissuade investors or lenders from engaging with us, potentially impacting our share price or access to capital across all of our operating jurisdictions (Gabon, Egypt, Cote d'Ivoire and Equatorial Guinea). Furthermore, the European Commission, in February 2025, adopted proposals to focus the Corporate Sustainability Reporting Directive (CSRD) primarily on the largest companies (those with over 1000 employees), which, while potentially easing burdens on smaller entities, reinforces the global trend towards increased sustainability reporting requirements and scrutiny for significant market participants.

While we may issue voluntary disclosures regarding ESG matters, these are often based on hypothetical expectations and assumptions that may not fully represent current or future risks, due to the inherent uncertainties, long timelines, and evolving methodologies for identifying, measuring, and reporting on many ESG topics. The approaches to climate change and the transition to a lower-carbon economy, including governmental regulations, corporate policies, and consumer behavior, are continuously evolving globally. Our operating countries, including Gabon, Egypt, Cote d'Ivoire, and Equatorial Guinea, are signatories to the Paris Agreement and are developing or implementing various climate-related strategies, NDCs, and regulations, including those aimed at reducing flaring, capping emissions, and promoting energy efficiency. We cannot reliably estimate the full impact of these evolving approaches on our financial condition, results of operations, and ability to compete.

Operational activities across our global footprint, including exploration and development, are increasingly subject to stringent social and environmental review. Certain social license risks, involving community engagement, land access, and local content requirements, are pertinent in all our operating countries and can affect our ability to obtain or renew necessary permits and approvals.

Any long-term material adverse effect on the global oil and gas industry, whether driven by climate policies, social pressures, or other ESG factors, may adversely affect our financial condition, results of operations, and cash flows. Such impacts could also arise from increased awareness and adverse publicity, restricting our access to capital or impacting the marketability of our crude oil, natural gas, and NGLs. The physical impacts of climate change, such as changes in weather patterns, sea levels, and temperatures, also pose highly uncertain but potentially significant risks to our operations in specific geographic areas. We cannot predict the full extent of how these multifaceted ESG and climate change considerations will ultimately affect us.

We face various risks associated with increased opposition to and activism against crude oil, natural gas and NGLs exploration and development activities.

The oil and natural gas exploration, development and operating activities that we conduct may, at times, be subject to public opposition. Opposition against crude oil, natural gas and NGLs drilling and development activity has been growing globally. Companies in the crude oil, natural gas and NGLs industry are often the target of activist efforts from both individuals and non-governmental organizations regarding safety, human rights, climate change, environmental matters, sustainability and business practices. Anti-development activists are working to, among other things, delay or cancel certain operations such as offshore drilling and development.

Such public opposition could expose us to higher costs, delays or even project cancellations, due to increased pressure on governments and regulators by special interest groups, including Indigenous groups, landowners, environmental interest groups (including those opposed to oil and natural gas production operations) and other non-governmental organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support from the federal, provincial or municipal governments, reputational damage, delays in, challenges to or the revocation of regulatory approvals, permits and/or licenses, and direct legal challenges, including the possibility of climate-related litigation. There is no guarantee that we will be able to satisfy the concerns of the special interest groups and non-governmental organizations, and attempting to address such concerns may require us to incur significant and unanticipated capital and operating expenditures.

Further, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector. Moreover, activist shareholders in our industry have introduced shareholder proposals that may seek to force companies to adopt aggressive emission reduction targets or to shift away from more carbon-intensive activities. While we cannot predict the outcomes of such proposals, they could ultimately make it more difficult for us to engage in exploration and production activities.

Risks Relating to Legal and Regulatory Matters

Our operations are subject to risks associated with climate change and potential regulatory programs meant to address climate change; these programs may impact or limit our business plans, result in significant expenditures or reduce demand for our product.

Climate change continues to be the focus of political and societal attention. Numerous proposals have been made and are likely to be forthcoming on the international, national, regional, state and local levels to reduce the emissions of GHG emissions. These efforts have included or may include cap-and-trade programs, carbon taxes, GHG emissions reporting obligations and other regulatory programs that limit or require control of GHG emissions from certain sources. These programs may limit our ability to produce crude oil, natural gas and NGLs, limit our ability to explore in new areas, or may make it more expensive to produce. In addition, these programs may reduce demand for our product either by incentivizing or mandating the use of other alternative energy sources, by prohibiting the use of our product, by requiring equipment using our product to shift to alternative energy sources, or by directly increasing the cost of fossil fuels to consumers. Additionally, in March 2024, the SEC adopted final rules intended to enhance and standardize climate-related disclosures by public companies and in public offerings. Immediately after the SEC's release of the final rules, several lawsuits were filed to challenge their legality, and the rules were stayed pending judicial review. On March 27, 2025, the SEC ended its defense of the final rules on climate-related disclosures, effectively withdrawing its support for the regulation; however, the rules remain on hold pending such legal challenges, which are currently held in abeyance by the Eighth Circuit Court of Appeals until such time as the SEC determines whether the rules will be rescinded, repealed, modified or defended in litigation.

Compliance with applicable environmental laws and other government regulations could be costly and could negatively impact production.

The laws and regulations of countries where we have activities control our current business. These laws and regulations may require that we obtain permits for our development activities, limit or prohibit drilling activities in certain protected or sensitive areas or restrict the substances that can be released in connection with our operations.

Our operations could result in liability for personal injuries, property damage, natural resource damages, crude oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. Failure to comply with environmental laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties and the issuance of orders enjoining operations. In addition, we could be liable for environmental damages caused by, among others, previous property owners or operators of properties that we purchase or lease. Some environmental laws provide for joint and several strict liabilities for remediation of releases of hazardous substances, rendering a person liable for environmental damage without regard to negligence or fault on the part of such person. As a result, we may incur substantial liabilities to third parties or governmental entities and may be required to incur substantial remediation costs. We could also be affected by more stringent laws and regulations adopted in the future, including any related to climate change and GHG and the use of hydraulic fracturing fluids, resulting in increased operating costs.

We are also subject to a wide variety of laws relating to health and safety, taxes, employment, labor standards, money laundering, terrorist financing, and other matters in the jurisdictions in which we operate.

These laws and other governmental regulations, which cover matters including drilling operations, taxation and environmental protection, may be changed from time to time in response to economic or political conditions and could have a significant impact on our operating costs, as well as the crude oil, natural gas and NGLs industry in general. The compliance mechanisms and monitoring programs that we have adopted and implemented may not adequately prevent or detect possible violations of such applicable laws. Our failure to comply with any such legislation could result in severe criminal or civil sanctions and may subject us to other liabilities, including fines, prosecution and reputational damage, all of which could have a material adverse effect on our business, consolidated results of operations and consolidated financial condition.

While we believe that we are currently in compliance with environmental laws and other government regulations applicable to our operations, no assurances can be given that we will be able to continue to comply with such environmental laws and regulations without incurring substantial costs.

We have been, and in the future may become, involved in legal proceedings with governmental bodies and private litigants, and, as a result, may incur substantial costs in connection with those proceedings.

Our business subjects us to liability risks from litigation or government actions. We have been involved in legal proceedings from time to time and may in the future be party to various lawsuits or governmental actions. There is risk that any matter in litigation could be decided unfavorably against us, which could have a material adverse effect on our financial condition, results of operations and cash flows. Litigation can be very costly, and the costs associated with defending litigation could also have a material adverse effect on our results of operation, net cash flows and financial condition. Adverse litigation decisions or rulings may also damage our business reputation.

Often, our operations are conducted through joint ventures over which we may have limited influence and control. Private litigation or government proceedings brought against us could also result in significant delays in our operations.

Risks Relating to the 2025 Facility Agreement

A significant level of indebtedness incurred under the 2025 Facility may limit our ability to borrow additional funds or capitalize on acquisition or other business opportunities in the future. In addition, the covenants in the 2025 Facility impose restrictions that may limit our ability and the ability of our subsidiaries to take certain actions. Our failure to comply with these covenants could result in the acceleration of any future outstanding indebtedness under the 2025 Facility.

The 2025 Facility Agreement governing our 2025 Facility with The Standard Bank of South Africa Limited, Isle of Man Branch, The Standard Bank of South Africa Limited, and the other financial institutions contains certain affirmative and negative covenants, including, among other things, as to compliance with laws (including environmental laws and anti-corruption laws), delivery of quarterly and annual financial statements and compliance certificates, no change of business, no merger and maintenance of corporate existence, field preservations and related contracts relating to the Borrowing Base Assets (as defined in the 2025 Facility Agreement), maintenance of insurance, entry into certain derivatives contracts which are regulated by the 2025 Facility Agreement and the Hedging Policy (as defined in the 2025 Facility Agreement), restrictions on the incurrence of liens, indebtedness, asset dispositions, acquisitions, restricted payments, entry into offtake agreements with Qualifying Offtakers (as defined in the 2025 Facility Agreement) and other customary covenants. The 2025 Facility Agreement also contains certain financial covenants and other covenants that restrict our ability to pay dividends and to enter into certain acquisitions and disposition transactions. We were in compliance with covenants under the 2025 Facility Agreement as of the date hereof.

Restrictions contained in the 2025 Facility Agreement governing any future indebtedness may reduce our ability to incur additional indebtedness, engage in certain transactions or capitalize on proposed acquisition or other business opportunities. Any future indebtedness under the 2025 Facility and other financial obligations and restrictions could have financial consequences. For example, they could:

- impair our ability to obtain additional financing in the future for capital expenditures, potential acquisitions, general business activities or other purposes;
- increase our vulnerability to general adverse economic and industry conditions;
- require us to dedicate a substantial portion of future cash flows to payments of our indebtedness and other financial obligations, thereby reducing the availability of our cash flows to fund working capital, capital expenditures and other general corporate requirements;
- limit our flexibility in planning for, or reacting to, changes in our business and industry; and
- place us at a competitive disadvantage to those who have proportionately less debt.

In addition, our ability to comply with the 2025 Facility Agreement's covenants could be affected by events beyond our control and we cannot assure you that we will satisfy those requirements. A prolonged period of oil and gas prices at depressed levels could further increase the risk of our inability to comply with covenants to maintain specified financial ratios. A breach of any of these provisions could result in a default under the 2025 Facility, which could allow all amounts outstanding thereunder to be declared immediately due and payable. In the event of such acceleration, we cannot assure that we would be able to repay our debt or obtain new financing to refinance our debt. Even if new financing was made available to us, it may not be on terms acceptable to us. We may also be prevented from taking advantage of business opportunities that arise if we fail to meet certain ratios or because of the limitations imposed on us by the covenants under the 2025 Facility.

The borrowing base under the 2025 RBL Facility may be reduced pursuant to the terms of the 2025 Facility Agreement, which may limit our available funding for exploration and development. We may have difficulty obtaining additional credit, which could adversely affect our operations and financial position.

In the future we may depend on the 2025 RBL Facility for a portion of our capital needs. The 2025 RBL Facility had initial aggregate commitments of $190 million and an initial borrowing base of $182 million. Subject to certain conditions, we may request, at any time prior to the date falling 30 months after the date of the 2025 Facility Agreement to increase the total commitments available under the 2025 RBL Facility to an aggregate principal amount not to exceed $300 million. In addition, subject to certain conditions precedent, certain existing Lenders under the 2025 RBL Facility agreed to increase their initial commitment effective January 23, 2026 (the “Effective Increase Date”) so that the aggregate borrowing base under the 2025 RBL Facility as of the Effective Increase Date increased from $190.0 million to $255.0 million. The increase in commitments was undertaken with the existing accordion feature included in the 2025 RBL Facility.

The total amount of loans which may be drawn under the 2025 Facility is limited to the lower of the amount of the aggregate commitments and the Borrowing Base Amount at the relevant time. The Borrowing Base Amount is calculated pursuant to the 2025 Facility Agreement and redetermined on March 31 and September 30 of each year beginning June 30, 2025 and other interim triggers set out in the 2025 Facility Agreement.

In the future, we may not be able to access adequate funding under the 2025 RBL Facility as a result of (i) a decrease in our borrowing base due to the outcome of a subsequent borrowing base redetermination, or (ii) an unwillingness or inability on the part of the lenders to meet their funding obligations. As a result, we may be unable to obtain adequate funding under the 2025 RBL Facility. If funding is not available when needed, or is available only on unfavorable terms, it could adversely affect our development plans as currently anticipated, which could have a material adverse effect on our production, revenues and results of operations.

Risks Relating to Ownership of Our Common Stock

The price of our Common Stock may fluctuate significantly.

Our common stock currently trades on the New York Stock Exchange (“NYSE”) and the London Stock Exchange (“LSE”), but an active trading market for our common stock may not be sustained. The market price of our common stock could fluctuate significantly as a result of:

- dilutive issuances of our common stock;
- announcements relating to our business or the business of our competitors;
- changes in expectations as to our future financial performance or changes in financial estimates of public market analysis;
- actual or anticipated quarterly variations in our operating results;
- conditions generally affecting the crude oil, natural gas and NGLs industry;
- the success of our operating strategy; and
- the operating and stock price performance of other comparable companies.

Many of these factors are beyond our control, and we cannot predict their potential effects on the price of our common stock. In addition, the stock markets can experience considerable price and volume fluctuations. Recent volatility in the financial markets has resulted in significant price and volume fluctuations that have affected the market prices of equity securities without regard to a company’s operating performance, underlying asset values or prospects. Accordingly, the market price of our common stock may decline even if our operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause decreases in asset values, which may result in impairment losses. There is no assurance that fluctuations in the price and volume of publicly traded equity securities will not occur. If such increased levels of volatility and market turmoil continue, our operations could be adversely impacted, and the trading price of our common stock may be adversely affected.

We currently intend to pay dividends on our common stock; however, no assurance can be given that we will be able to pay dividends to our stockholders in the future at indicated levels or at all.

Our Board of Directors adopted a quarterly cash dividend policy of an expected $0.0625 per share of common stock commencing in the first quarter of 2023. To the extent we have adequate cash on hand and cash flows from operations, we will consider continuing to pay dividends on our common stock in the future. Payment of future dividends, if any, and the establishment of future record and payment dates will be at the discretion of our Board of Directors after taking into account various factors, including current financial condition, the tax impact of repatriating cash, operating results and current and anticipated cash needs. As a result, no assurance can be given that we will be able to continue to pay dividends to our stockholders or that the level of any future dividends will achieve a market yield or increase or even be maintained over time, any of which could materially and adversely affect the market price of our common stock.

Dual-listing on the NYSE and the LSE may lead to an inefficient market in our common stock.

Our common stock is quoted on the NYSE and the LSE. Consequently, the trading in and liquidity of our common stock are split between these two exchanges. The price of our common stock may fluctuate and may at any time be different on the NYSE and the LSE. Dual-listing of our common stock will result in differences in liquidity, settlement and clearing systems, trading currencies, and prices and transaction costs between the exchanges where our common stock will be quoted. These and other factors may hinder the transferability of our common stock between the two exchanges.

Investors could seek to sell or buy our common stock to take advantage of any price differences between the two markets through a practice referred to as arbitrage. Any arbitrage activity could create unexpected volatility in both common stock prices on either exchange and in the volumes of our common stock available for trading on either market. This could adversely affect the trading of our common stock on these exchanges and increase their price volatility and/or adversely affect the price and liquidity of the shares of common stock on these exchanges. In addition, holders of our common stock in either jurisdiction will not be immediately able to transfer such shares for trading on the other market without effecting necessary procedures with our transfer agents/registrars. This could result in time delays and additional cost for stockholders.

Our common stock is quoted and traded in USD on the NYSE and traded in GBX on the LSE. The market price of our common stock on those exchanges may also differ due to exchange rate fluctuations.

Substantial future sales of our common stock, or the perception that such sales might occur, or additional offerings of our common stock could depress the market price of our common stock.

We cannot predict what effect, if any, future sales of our common stock, or the availability of our common stock for future sale, or the offer of additional shares of our common stock in the future, will have on the market price of our common stock. Sales or an additional offering of substantial number of shares of our common stock in the public market, or the perception or any announcement that such sales or an additional offering could occur, could adversely affect the market price of our common stock and may make it more difficult for stockholders to sell their common stock at a time and price that they deem appropriate and could also impede our ability to raise capital through the issuance of equity securities.

Any issuance of preferred shares will rank in priority to our shares of common stock.

While we do not currently have any preferred shares outstanding, under our certificate of incorporation, we are authorized to issue up to 500,000 preferred shares. Any issuance of preferred shares would rank in priority to our shares of common stock with respect to the payment of dividends, liquidation, and other matters.

Our certificate of incorporation and bylaws do not contain any rights of pre-emption in favor of existing stockholders, which means that stockholders may be diluted if additional shares of common stock are issued.

Our stockholders do not have pre-emptive rights and we, without stockholder consent, may issue additional shares of common stock, preferred shares, warrants, rights, units and debt securities for general corporate purposes, including, but not limited to, working capital, capital expenditures, investments, acquisitions and repayment or refinancing of borrowings. We actively seek to expand our business through complementary or strategic acquisitions and may issue additional shares of common stock in connection with those acquisitions. We also issue shares of our common stock to our executive officers, employees and independent directors as part of their compensation. This may have the effect of diluting the interests of existing stockholders. Additionally, to the extent that pre-emptive rights are granted, stockholders in certain jurisdictions may experience difficulties in exercising or the inability to exercise their pre-emptive rights.

The choice of forum provisions in our Third Amended and Restated Bylaws (the "Bylaws") could limit our stockholders' ability to obtain a favorable judicial forum for disputes.

Our Bylaws provide that the Court of Chancery of the State of Delaware (or, if the Court of Chancery does not have jurisdiction, the federal district court for the District of Delaware) shall be the sole and exclusive forum for (i) any derivative action or proceeding brought in the name or right of the Company or on its behalf, (ii) any action asserting a claim for breach of a fiduciary duty owed by any director, officer, employee, stockholder or other agent of the Company to the Company or the stockholders, (iii) any action arising or asserting a claim arising pursuant to any provision of the General Corporation Law of Delaware (the "DGCL") or any provision of our Restated Certificate of Incorporation, as amended (the "Charter"), or the Bylaws or as to which the DGCL confers jurisdiction on the Court of Chancery of the State of Delaware or (iv) any action asserting a claim governed by the internal affairs doctrine, including, without limitation, any action to interpret, apply, enforce or determine the validity of the Charter or the Bylaws. Nonetheless, pursuant to our Bylaws, the foregoing provisions will not apply to suits brought to enforce a duty or liability created by the Exchange Act or any other claim for which the federal courts have exclusive jurisdiction. Our Bylaws further provide that unless we consent in writing to the selection of an alternative forum, the federal district courts of the U.S. shall be the exclusive forum for the resolution of any complaint asserting a cause of action arising under the Securities Act. Under the Securities Act, federal and state courts have concurrent jurisdiction over all suits brought to enforce any duty or liability created by the Securities Act, and stockholders cannot waive compliance with the federal securities laws and the rules and regulations thereunder. Accordingly, there is uncertainty as to whether a court would enforce such a forum selection provision as written in connection with claims arising under the Securities Act. Any person or entity purchasing or otherwise acquiring any interest in shares of our capital stock will be deemed to have notice of and have consented to the provisions in the Bylaws related to choice of forum. The choice of forum provisions in our Bylaws may limit our stockholders' ability to obtain a favorable judicial forum for disputes with us. Additionally, the enforceability of choice of forum provisions in other companies' governing documents has been challenged in legal proceedings, and it is possible that, in connection with any applicable action brought against us, a court could find the choice of forum provisions contained in our Bylaws to be inapplicable or unenforceable in such action. If so, we may incur additional costs associated with resolving such action in other jurisdictions, which could harm our business, results of operations, and financial condition.

Item 1B. Unresolved Staff Comments

None.

Item 1C. Cybersecurity

Risk management and strategy

Our corporate information technology, communication networks, enterprise applications, accounting and financial reporting platforms, and related systems are necessary for the operation of our business. We use these systems, among others, to manage our exploration, development and production processes, for internal communications, for accounting to operate record-keeping function, and for many other key aspects of our business. Our business operations rely on the secure collection, storage, transmission, and other processing of proprietary, confidential, and sensitive data.

We have implemented and maintain various information security processes designed to identify, assess and manage material risks from cybersecurity threats to our critical computer networks, third-party hosted services, communications systems, hardware and software, and our critical data, including confidential information that is proprietary, strategic or competitive in nature ("Information Systems and Data").

We rely on a multidisciplinary team, including our information security function, legal department, management, and third-party service providers, as described further below, to identify, assess, and manage cybersecurity threats and risks. We identify and assess risks from cybersecurity threats by monitoring and evaluating our threat environment and our risk profile using various methods including, for example, using manual and automated tools, subscribing to reports and services that identify cybersecurity threats, analyzing reports of threats and threat actors, conducting scans of the threat environment, evaluating our industry's risk profile, utilizing internal and external audits, and conducting threat and vulnerability assessments.

Depending on the environment, we implement and maintain various technical, physical, and organizational measures, processes, standards, and/or policies designed to manage and mitigate material risks from cybersecurity threats to our Information Systems and Data, including risk assessments, incident detection and response, vulnerability management, disaster recovery and business continuity plans, internal controls within our accounting and financial reporting functions, encryption of data, network security controls, access controls, physical security, asset management, systems monitoring, vendor risk management program, infrastructure protection technologies, disaster recovery plans, employee training, and penetration testing.

We work with third parties from time to time that assist us in identifying, assessing, and managing cybersecurity risks, including professional services firms, consulting firms, threat intelligence service providers and penetration testing firms.

To operate our business, we utilize certain third-party service providers to perform a variety of functions. We seek to engage reliable, reputable service providers that maintain cybersecurity programs. Depending on the nature of the services provided, the sensitivity and quantity of information processed, and the identity of the service provider, our vendor management process may include reviewing the cybersecurity practices of such provider, contractually imposing obligations on the provider, conducting security assessments, and conducting periodic reassessments during their engagement.

We are not aware of any risks from cybersecurity threats, including as a result of any cybersecurity incidents, which have materially affected or are reasonably likely to materially affect our Company, including our business strategy, results of operations, or financial condition. Refer to “Item 1A. Risk factors” in this Annual Report on Form 10-K, including “Our business could be materially and adversely affected by security threats, including cybersecurity threats, and other disruptions”, for additional discussion about cybersecurity-related risks.

Governance

Our Board of Directors holds oversight responsibility over the Company’s strategy and risk management, including the management of systemic risks and material risks related to cybersecurity threats. This oversight is performed by the Board of Directors and its committees. The Board of Directors engages in discussions with management when management identifies any significant financial risk exposures that may result from material cybersecurity threats and the measures implemented to monitor and control these risks.

Our management, represented by our Chief Financial Officer, Ron Bain, and our Information Technology Director (the “IT Director”), Ryan Fernandez, leads our cybersecurity risk assessment and management processes and oversees their implementation and maintenance.

Our IT Director is an experienced information technology professional in our information technology department and has served as IT Director since November 2025. He works with the Company’s internal information technology department and external partners to monitor and improve our cybersecurity capabilities. Our IT Director possesses extensive experience in technology and cybersecurity, gained over his career spanning more than 25 years. Our previous IT Director, Perry Pasloski, led our IT department since 2024 prior to transitioning out of his role in November 2025 and leaving the Company in February 2026.

Management, in coordination with our information technology department, is responsible for hiring appropriate personnel, helping to integrate cybersecurity risk considerations into the Company’s overall risk management strategy, and communicating key priorities to relevant personnel. Management is responsible for approving budgets, approving cybersecurity processes, and reviewing cybersecurity assessments and other cybersecurity-related matters.

Our cybersecurity incident response and vulnerability management processes are designed to escalate certain cybersecurity incidents to members of management depending on the circumstances. Management, including the IT Director and the Chief Financial Officer, serves on the Company’s incident response team to help the Company mitigate and remediate cybersecurity incidents of which they are notified. In addition, the Company’s incident response processes include reporting to the Board of Directors for certain cybersecurity incidents. The Board of Directors holds regular meetings throughout the year and receives periodic reports from management, including our Chief Financial Officer, concerning the Company’s significant cybersecurity threats and risk and the processes the Company has implemented to address them.

Item 2. Properties

The location and general character of our principal crude oil, natural gas and NGLs assets, production facilities, and other important physical properties have been described by segment under Item 1. “*Business*.” Information about crude oil, natural gas and NGLs reserves, including the basis for their estimation, is discussed in Item 1. “*Business*.” Our principal executive office is located at 2500 CityWest Boulevard, Houston, Texas 77042. As of December 31, 2025, we maintained offices in Houston, Texas; London, United Kingdom; Port-Gentil, Gabon; Calgary, Alberta; Cairo, Egypt; Abidjan, Cote d’Ivoire; and Malabo, Equatorial Guinea. All of our office space is leased. While we may in the future require additional office space as our business expands, we believe that our existing facilities are adequate to meet our needs for the immediate future and that additional facilities will be available on commercially reasonable terms as needed. For information regarding the Company’s obligations under its office leases, see Part IV, Item 15., Note 13. *Leases* to the Consolidated Financial Statements.

Item 3. Legal Proceedings

We are subject to litigation claims and tax, governmental and regulatory proceedings arising in the ordinary course of business. While we cannot predict the occurrence or outcome of these proceedings with certainty, it is management's opinion that all claims and litigation we are currently involved in are not likely to have a material adverse effect on our consolidated financial position, cash flows or results of operations.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is traded on the New York Stock Exchange and London Stock Exchange under the symbol "EGY".

As of February 28, 2026, based upon information received from our transfer agent and brokers and nominees, there were approximately 101 holders of record of VAALCO common stock. This number does not include beneficial or other owners for whom common stock may be held in "street" names.

Dividends

Our Board of Directors adopted a quarterly cash dividend policy of an expected $0.0625 per common share per quarter commencing in the first quarter of 2023. The following table is a schedule of our dividends paid during 2025:

Dividend Payment Date	Amount per common share	Record Date
March 28, 2025	$0.0625	February 28, 2025
June 27, 2025	$0.0625	May 23, 2025
September 19, 2025	$0.0625	August 22, 2025
December 24, 2025	$0.0625	November 21, 2025
Aggregate per share amount paid in 2025	$0.2500	

In connection with the 2025 RBL Facility, we are required to provide a group liquidity forecast prior to any distribution, share buyback, or stock repurchase (each, a "Distribution"). The forecast must include the amount of Distribution expected in the forecast period. Provided there is no borrowing base deficiency, and no event of default results or exists, we may make Distributions without further approval as long as (1) the current forecast is above the required ratio and the proposed Distribution, aggregated with the amount declared or paid in any three months within the forecast period, does not exceed 110% of the estimated amount for that period, or (2) we provide an updated forecast that is above the required threshold taking into account the proposed Distribution and the expected Distribution in any three-month period within the relevant forecast period. In the event the liquidity test is not met, an approval or waiver would need to be obtained from the Lenders to make a Distribution. Cash dividends during the expected period of the refurbishment of the FPSO in Cote d'Ivoire, if any are declared, shall not be more than $0.26 per share. For the year ended December 31, 2025, no specific approval or waivers were required to make Distributions.

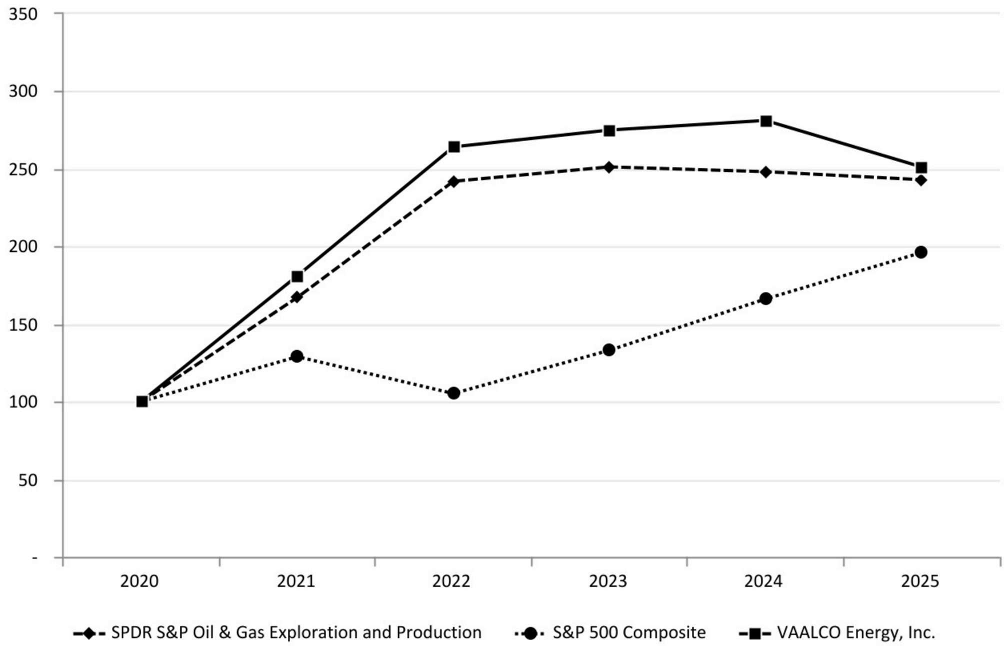
To the extent we have adequate cash on hand and cash flows from operations, we will consider paying additional cash dividends on a quarterly basis; however, any future dividend payments, if any, will be at the discretion of the Board of Directors after taking into account various factors, including current financial condition, the tax impact of repatriating cash, operating results and current and anticipated cash needs.

Securities Authorized for Issuance Under Equity Compensation Plans

See "*Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*" for discussion of shares of common stock that may be issued under our compensation plans.

Performance Graph

The following graph compares the annual percentage change in our cumulative total stockholder return on common shares with the cumulative total return of the S&P 500 Index and the SPDR S&P Oil & Gas Exploration and Production Index. The graph assumes $100 was invested on December 31, 2020 in our common stock and in each index, and that all dividends, if any, are reinvested. Stockholder returns over the indicated period may not be indicative of future stockholder returns.



	2020	2021	2022	2023	2024	2025
SPDR S&P Oil & Gas Exploration and Production	$ 100	$ 167	$ 242	$ 251	$ 248	$ 243
S&P 500 Composite	$ 100	$ 129	$ 105	$ 133	$ 166	$ 196
VAALCO Energy, Inc.	$ 100	$ 181	$ 264	$ 275	$ 281	$ 251

Unregistered Sales of Equity Securities and Use of Proceeds

There were no sales of unregistered securities during the year ended December 31, 2025 that were not previously reported on a Current Report on Form 8-K.

Issuer Repurchases of Common Stock

The Company previously implemented a Rule 10b5-1 trading plan (the “10b5-1 Plan”) to facilitate share purchases through open market purchases, privately negotiated transactions, or otherwise under the Exchange Act. The 10b5-1 Plan provided for an aggregate purchase of currently outstanding common stock of up to $30 million over a maximum period of up to 20 months. Payment for shares repurchased under the share buyback program were funded using the Company's cash on hand and cash flow from operations. The share buyback program was completed on March 12, 2024.

Item 6. [Reserved].

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following management's discussion and analysis describes the principal factors affecting our capital resources, liquidity, and results of operations. This management's discussion and analysis should be read in conjunction with the accompanying Financial Statements and related notes, information about our business practices, significant accounting policies, risk factors, and the transactions that underlie our financial results, which are included in various parts of this Annual Report. For discussion related to changes in financial condition and results of operations for 2024 as compared with 2023, refer to Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2024 Form 10-K, which was filed with the SEC on March 17, 2025. Certain statements in our discussion below are forward-looking statements. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause actual results to differ materially from those implied or expressed by the forward-looking statements. Please see "Cautionary Statement Regarding Forward-Looking Statements" and "Item 1A. Risk Factors" for further details about these statements.

INTRODUCTION

We are an independent energy company headquartered in Houston, Texas engaged in the acquisition, exploration, development and production of crude oil, natural gas and NGLs. We have a diversified African-focused portfolio of production, development and exploration assets located in Gabon, Egypt, Cote d'Ivoire, Equatorial Guinea, Nigeria, as well as, prior to the Canada Asset Divestment, producing properties in Canada. For further discussion of our five operating segments see *"Item 1. Business – Segment and Geographical Information."*

We intend to accelerate shareholder returns and increase shareholder value by controlling operating costs and capital expenditures, maximizing reserve recoveries and making disciplined strategic accretive acquisitions that meet our strategic and financial objectives.

We believe that our quality portfolio, strong management and technical expertise specific to the markets in which we operate, and our ongoing focus on maintaining a competitive cost structure and disciplined capital allocation framework position us to achieve our business strategy and navigate a variety of commodity price environments. Over the past years, we have delivered on our focused strategy and believe we will continue to do so with the organic growth programs across our diversified portfolio over the coming years.

Recent Developments and Outlook

2025 Acquisition

In March 2025, the Company farmed into the CI-705 block offshore Côte d'Ivoire as the operator with a 70% working interest and a 100% paying interest though a commercial carry arrangement with two other parties inclusive of the State Oil Company. The CI-705 block is located in the Tano basin, west of the Company's CI-40 Block, where the Baobab and Kossipo oil fields are located. The total amount of acquisition costs for this transaction is approximately $3.0 million.

Divestment of Non-Core Assets

On February 4, 2026, the Company entered into an asset purchase agreement (the "Canada APA") to sell all its operating assets in Canada (the "Canada Asset Divestment") for a purchase price of $24.4 million (C$33.4 million Canadian dollars), subject to customary adjustments. The Canada Asset Divestment closed on February 19, 2026 with an effective date of February 1, 2026 for an adjusted purchase price of $25.5 million. The Canada Asset Divestment represents the Company's complete exit of its Canadian oil and gas operations. Please see Part IV, Item 15., Note 4. *Acquisitions and Divestiture* and Note 20. *Subsequent Events*, to the Consolidated Financial Statements for further discussion on the Canada Asset Divestment.

Capital Program

We expect our 2026 capital program to range between $290.0 million to $360.0 million, assuming normal operating conditions, which prioritizes free cash flow generation and meaningful return of capital to shareholders. The program includes estimated spending of approximately between $110.0 million to $135.0 million for Gabon, $9.0 million to $12.0 million for Egypt, $0.5 million to $1.5 million for Equatorial Guinea, $170.0 million to $210.0 million for Cote d'Ivoire for oil and natural gas development and $0.5 to $1.5 million related to corporate and other capital costs. The foregoing amounts related to Etame projects in Gabon do not include amounts funded by the non-operating partners. See below under

"Capital Resources, Liquidity and Cash Requirements" for further discussion on the capital spending for each of our operating segments.

Commodity Prices

Prices for crude oil and condensate, NGLs and natural gas have historically been volatile. This volatility is expected to continue due to the many uncertainties associated with the worldwide political and economic environment and the global supply of, and demand for, crude oil, NGLs and natural gas and the availability of other energy supplies, the relative competitive relationships of the various energy sources in the view of consumers and other factors. Significant changes in oil and natural gas prices have a material impact on our liquidity. Declining commodity prices negatively affect our operating cash flow but have a positive indirect effect on operating expenses. The inverse is also true during periods of rising commodity prices. To mitigate some of the risk inherent in oil and natural gas prices, we have utilized various derivative instruments to hedge commodity price risk.

Trends and Uncertainties

Geopolitical Conflict and Other Market Forces – The Company continues to monitor geopolitical developments globally, and specifically in Europe, the Middle East, Africa, and North America, where they have the potential to impact operational continuity and market dynamics. On October 9, 2025, Israel, Hamas, the United States and other countries in the region agreed to a framework for a ceasefire in Gaza between Israel and Hamas, which if sustained, could reduce regional instability in the Eastern Mediterranean, and improve security conditions affecting Egypt operations and related energy supply chains. However, such ceasefire has not progressed beyond the first phase, and whether the ceasefire will be sustained or will result in a lasting de-escalation of tensions in the region is unknown. Additionally, geopolitical tensions and localized disruptions persist in parts of West Africa, where we hold significant producing and development interests, require ongoing vigilance regarding political, economic, and security risks.

Global markets are also experiencing volatility and uncertainty connected to the United States-Israel-Iran war and U.S intervention in Venezuela. Following the February 2026 missile strikes in Iran, there has been increased instability, including airspace closures in the Middle East, damage to airports and the de facto closure of Strait of Hormuz, a waterway that transports approximately 20% of the world's petroleum. The duration and impact of these ongoing armed conflicts, and the potential of these conflicts spreading to more regions is uncertain and could adversely affect the global economy, financial markets, our customers and in turn us.

Additionally, geopolitical tensions and localized disruptions persist in parts of West Africa, where we hold significant producing and development interests, require ongoing vigilance regarding political, economic, and security risks.

Additionally, global market forces including inflation, supply chain constraints due to lingering impacts from conflicts such as the Russia-Ukraine war, and shifts in U.S. trade policy including tariffs on energy-related goods, continue to increase costs and extend lead times for equipment and materials essential to drilling and production activities. These factors could affect project timing, cost structures, and overall operational efficiency. The Company also notes ongoing volatility in commodity prices driven by dynamic supply and demand fundamentals, energy transition policies, and broader macroeconomic uncertainties. Vaalco actively manages exposure to these risks through operational flexibility, diversified sourcing, and prudent financial planning to safeguard long-term growth and value creation.

U.S. Tariffs and Global Trade Policies – In 2025, the U.S. administration enacted sweeping trade legislation, including significant tariff increases on industrial goods, energy-related equipment, and certain critical minerals, with a stated intent to prioritize domestic manufacturing and energy security. Global trade policy continues to evolve and the ultimate impact of recent developments with respect to U.S. tariffs is unclear. On February 20, 2026, the United States Supreme Court issued a ruling striking down certain tariffs previously imposed under the International Emergency Economic Powers Act ("IEEPA"). Following the Supreme Court's decision, the U.S. presidential administration announced its intention to invoke other laws to collect tariffs and announced new tariffs on imports from all countries, in addition to any existing non-IEEPA tariffs. While there is significant uncertainty as to the duration of these and any further tariffs, and the impacts these tariffs and any corresponding retaliatory tariffs will have on the oil and gas industry and on commodity prices, these tariffs, along with anticipated retaliatory measures from affected trading partners, have introduced new volatility into the global supply chain for energy infrastructure.

While we do not maintain U.S. based production assets, our operations on the continent of Africa rely on equipment, services, and materials that are often sourced, engineered, or consolidated through the United States or through U.S. aligned trading routes. As a result, we may experience increased costs and longer lead times for the procurement and delivery of drilling and production equipment, particularly if suppliers adjust pricing in response to increased duties or if we are required to diversify sourcing channels. These impacts could affect the timing, cost structure and execution risk of certain development activities, especially in frontier offshore environments.

Additionally, the evolving global trade environment may increase compliance complexity and affect the cost efficiency of international operations. Enhanced documentation requirements and new rules of origin associated with U.S. trade actions could impact our ability to efficiently move materials through international logistics hubs, such as those in Houston, Texas and could necessitate additional internal resources to maintain compliance. These complexities necessitate additional internal resources to ensure sustained compliance and efficient material flow.

The broader geopolitical trade environment, including retaliatory tariffs and ongoing trade tensions with key partners, continues to inject volatility into the global supply network, necessitating vigilant risk management and strategic sourcing to mitigate operational disruptions and cost impacts.

Enactment of the One Big Beautiful Bill Act of 2025 – On July 4, 2025, the budget reconciliation bill known as the One Big Beautiful Bill Act of 2025 ("OBBBA") was signed into law, which includes significant changes to federal tax law and other regulatory provisions that may impact the Company. Among other provisions, the OBBBA makes permanent key elements of the Tax Cuts and Jobs Act of 2017. The legislation has multiple effective dates, with certain provisions effective in 2025 and others implemented through 2027. The impact of provisions effective in 2025 are not material and the Company is still assessing the impact of provisions that are not yet effective.

Moreover, to the extent U.S. policy shifts create uncertainty in bilateral relations or disrupt traditional trade partnerships, there could be indirect effects on our ability to manage risk and maintain favorable operating conditions in host countries. While we continue to monitor the evolving regulatory and trade landscape, we cannot predict the full impact of current or future tariffs, trade restrictions or retaliatory actions on our operations, financial condition or future capital deployment decisions.

Commodity Prices – Historically, the markets for oil, natural gas and NGLs have been volatile. Oil, natural gas and NGLs prices are subject to wide fluctuations in supply and demand. Our cash flows from operations may be adversely impacted by volatility in crude oil and natural gas prices, a decrease in demand for crude oil, natural gas or NGLs and future production cuts by OPEC. In addition, recent U.S. energy policy changes that prioritize domestic production and energy security, including through tax credits and development incentives, may influence global supply dynamics and capital flows, potentially altering the competitive landscape for international assets.

ESG and Climate Change Effects – Sustainability matters continue to attract public, political, regulatory and scientific attention.

While 2025 has seen a deceleration in the adoption of sustainability-oriented regulation, particularly in the U.S., and a noticeable shift by some financial institutions away from explicitly "ESG" or "Net Zero" branded initiatives due to perceived political or reputational sensitivities, we believe the underlying trend of focusing on sustainability remains consistent. Long-term structural pressures, including stakeholder expectations, evolving global market standards, and transition-related investment priorities, continue to support the integration of sustainability considerations into corporate strategy and capital markets.

The attention to climate change and environmental stewardship coupled with increasing government incentives around renewable energy sources may result in demand shifts away from crude oil and natural gas products, higher regulatory and compliance costs, additional governmental investigations and private litigation against the oil and gas industry, including Vaalco. For example, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes, voluntary efforts to reduce routine flaring, GHG reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. In addition, institutional investors, proxy advisory firms and other industry participants continue to focus on ESG matters, including climate change. We expect that this heightened focus will continue to drive ESG efforts across our industry and influence investment and voting decisions, which for some investors may lead to less favorable sentiment towards carbon assets and diversion of investment to other industries.

Climate-Related Disclosures – On March 27, 2025, the SEC ended its defense of the final rules on climate-related disclosures, effectively withdrawing its support for the regulation. The rules, which were adopted in March 2024, require publicly traded companies to disclose climate-related risks and greenhouse gas emissions. The SEC's decision to end its defense was made after a change in administration and a shift in policy, with Acting Chairman Mark Uyeda expressing concerns about the rule's costs and intrusiveness. While the rules remain on hold pending legal challenges, which, as of

September 2025, have been held in abeyance by the Eighth Circuit Court of Appeals until such time as the SEC reconsiders the challenged rules by notice-and-comment rulemaking or renews its defense of the rules, the SEC's withdrawal of support signals a potential shift in direction for climate disclosure regulations. Despite this regulatory shift in the U.S., we remain committed to maintaining transparency and aligning with industry standards for similarly situated companies.

U.S. activity notwithstanding, the landscape for international climate-related financial reporting has evolved significantly. The Task Force on Climate-related Financial Disclosures ("TCFD"), which previously served as a leading framework, ceased operations in early 2024, with its responsibilities and legacy transitioning to the International Sustainability Standards Board (ISSB).

In line with this global evolution, in June 2025, the UK government advanced its endorsement process for sustainability reporting standards by publishing exposure drafts for UK Sustainability Reporting Standards ("UK SRS") S1 and S2, derived from the International Financial Reporting Standards ("IFRS") S1 and S2 frameworks, and initiated a public consultation scheduled to conclude in autumn 2025. Pending final government approval and subsequent Financial Conduct Authority (FCA) rulemaking, UK listed businesses will be subject to phased implementation starting with climate-related disclosures, excluding Scope 3 greenhouse gas emissions in the first period, transitioning to full coverage in subsequent years. The UK approach eliminates fixed commencement dates and offers regulatory flexibility, with transitional reliefs supporting issuer compliance and a "climate-first" methodology for initial reports, ensuring a measured shift from existing TCFD requirements to the new UK SRS/IFRS-aligned disclosure regime. UK listed entities are advised to prepare for mandatory reporting in line with IFRS S1 and S2, anticipated from accounting periods beginning in 2026, subject to the outcomes of the consultation and final government direction.

RESULTS OF OPERATIONS

Year Ended December 31, 2025 Compared to Year Ended December 31, 2024

We reported a net loss for the year ended December 31, 2025 of $41.4 million compared to a net income of $58.5 million for the year ended December 31, 2024. The year-over-year decrease in net income was due primarily to an impairment loss on assets held for sale for our Canada segment, a decrease in revenues partially offset by decreases in depreciation, depletion and amortization expense, credit losses and income tax expense during the current year.

Further discussion of results by significant line item follows.

	Year Ended December 31,		Increase/
	2025	**2024**	**(Decrease)**
(in thousands except Boe and per Boe and per Bbl information)			
Net crude oil, natural gas and NGLs production (MBoe)	**6,043**	7,296	(1,253)
Net crude oil, natural gas, and NGLs sales volume (MBoe)	**6,370**	7,262	(892)
Average crude oil, natural gas and NGLs sales price (per Boe)	**$ 56.11**	$ 65.64	$ (9.53)
Average Dated Brent spot price* ($/Bbl)	**$ 69.14**	$ 80.52	$ (11.38)
Net crude oil, natural gas, and NGLs revenue	**$ 359,272**	$ 478,988	$ (119,716)
Operating costs and expenses:			
Production expense	**158,177**	163,500	(5,323)
Exploration expense	**8,914**	48	8,866
Depreciation, depletion and amortization	**109,978**	143,034	(33,056)
Impairment loss on assets held for sale	**67,224**	—	67,224
General and administrative expense	**33,089**	29,684	3,405
Credit (recovery) losses and other	**106**	6,304	(6,198)
Total operating costs and expenses	**377,488**	342,570	34,918
Other operating income (expense), net	**(2,391)**	78	(2,469)
Operating income (loss)	**(20,607)**	136,496	$ (157,103)
Other expense, net	**(5,962)**	3,301	(9,263)
Income (loss) before income taxes	**(26,569)**	139,797	(166,366)
Income tax expense	**14,822**	81,307	(66,485)
Net income (loss)	**$ (41,391)**	$ 58,490	$ (99,881)

* Average of daily Dated Brent spot prices posted on the U.S. Energy Information Administration website.

Crude oil, natural gas and NGLs net revenues decreased $119.7 million, or approximately 25%, during the year ended December 31, 2025 compared to the same period of 2024. The revenue decrease is primarily attributable to lower revenues in Gabon and Côte d'Ivoire.

Gabon

Crude oil sales in Gabon are a function of the number and size of crude oil liftings in each year and thus crude oil sales do not always coincide with volumes produced in any given year. The Company's Gabon segment contributed $181.7 million of revenue to the Company's total revenue during the year ended December 31, 2025, which is lower than the $206.0 million of revenue contributed by the segment in 2024. The decrease in revenues is primarily due to a decrease in the Gabon average realized price per barrel received during the year ended December 31, 2025 of $65.76 per barrel (Bbl) compared to the price received in 2024 of $78.81 per Bbl. Partially offsetting this decrease in revenues was a slightly higher sales volume for the year ended December 31, 2025 of 2,735 MBbls or 151 MBbls higher than the sales volume of 2,584 MBbls in the same period in 2024. Our share of crude oil inventory, excluding royalty barrels, was approximately 67 MBbls and 268 MBbls at December 31, 2025 and 2024, respectively.

Egypt

Crude oil sales in Egypt are either sold to a third party via a cargo lifting or sold directly to the government, EGPC. The Company's Egypt segment contributed $140.0 million of revenue to the Company's total revenue for the year ended December 31, 2025 compared to $146.0 million of revenue contributed by the segment in 2024. The decrease in revenues was primarily due to a lower average realized price received in Egypt of $51.27 per Bbl during the year ended December 31, 2025, which was $5.20 lower per Bbl compared to the $56.47 per Bbl received in 2024. This was partially offset by an increase in sales volumes during the year ended December 31, 2025 to 2,730 MBbls compared to 2,585 MBbls during the same period in 2024. The Company's Egypt segment had no oil inventory at December 31, 2025.

Canada

Prior to the Canada Asset Divestment, crude oil sales in Canada were normally sold through pipelines to a third party. The Company's Canadian segment contributed $19.2 million of revenue to the Company's total revenue for the year ended December 31, 2025, a decrease from the $32.0 million of revenue contributed by the Canada Segment in 2024. The decrease in revenues is due to the lower average realized sales price received during the year ended December 31, 2025 of $28.74 per MBoe or a decrease of $8.03 per Boe from the $36.77 per Boe received during the same period in 2024. In addition, there was a decrease in total sales volumes for the year ended December 31, 2025 to 667 MBoe from the 870 MBoe sold during the same period in 2024 which contributed to the decrease in revenues. The Company's Canadian segment had no oil inventory at December 31, 2025.

Cote d'Ivoire

Crude oil sales in Côte d'Ivoire are sold through a marketing contract with an international oil trading company which offers the cargo shipments to buyers, mainly refineries, around the world. As previously noted, the FPSO ceased production in January 2025 to undergo a planned dry dock refurbishment. The refurbishment work was completed in February 2026 and the Baobab FPSO has commenced its mobilization back to Cote d'Ivoire. The FPSO is expected to return to service during the fourth quarter of 2026. The Company's Côte d'Ivoire segment contributed $18.4 million of revenue to the Company's total revenue for the year ended December 31, 2025 or $76.7 million lower than the $95.1 million of revenue contributed by the segment in 2024. The decrease in revenues was primarily due to the decrease in sales volumes during the year ended December 31, 2025 to 238 MBbls compared to 1,223 MBbls during the same period in 2024. The average realized price received in Côte d'Ivoire was $77.36 per Bbl during the year ended December 31, 2025, which was also slightly lower compared to the $77.74 per Bbl received in 2024. The Company's Côte d'Ivoire segment had no oil inventory at December 31, 2025.

Production expenses decreased $5.3 million, or approximately 3%, to $158.2 million in the year ended December 31, 2025 compared to the same period of 2024. The decrease in production expense was primarily driven by a reduction in production expenses in our Côte d'Ivoire segment partially offset by an increase in expenses in our Gabon segment. On a per barrel basis, production expense, excluding workover expense and stock compensation expense, for the year ended December 31, 2025 increased to $24.78 per barrel from $22.48 per barrel for the year ended December 31, 2024. The increase in production cost per barrel is primarily due to a 17% decrease in production volumes compared to the prior year.

*Exploration expen*ses for the year ended December 31, 2025 of $8.9 million was attributable to the purchase of seismic data to be used in Block 705 in Cote d'Ivoire, the costs associated with Blocks G and H in Gabon and the costs associated with the Egypt exploration well in South Ghazalat determined to be not commercially viable. Exploration costs incurred during the same period in 2024 was minimal.

Depreciation, depletion and amortization decreased $33.1 million, or approximately 23%, to $110.0 million in the year ended December 31, 2025 compared to the same period of 2024. The decrease in depreciation, depletion and amortization expense is due primarily to no production in Côte d'Ivoire since January 2025 when the FPSO went offline.

General and administrative expenses increased $3.4 million, or approximately 11%, to $33.1 million in the year ended December 31, 2025 compared to the same period of 2024. The increase in general and administrative expenses is primarily due to an increase in stock based compensation, salaries and wages, and professional service fees.

Credit loss and other allowances - Credit loss and other expense decreased $6.2 million, or approximately 98%, to $0.1 million in the year ended December 31, 2025 compared to the same period of 2024. The credit losses and other for the year ended December 31, 2024 was primarily attributable to the higher allowance calculated during 2024 related to the Egypt

Backdated Receivables, defined in Part IV, Item 15., Note 11. *Commitments and Contingencies* to the Consolidated Financial Statements. The Backdated Receivables were settled as of March 31, 2025, while the remaining trade receivables are current and therefore it was determined that no provision was required.

Derivative instruments gain (loss), net is attributable to our commodity instruments as discussed in Part IV, Item 15., Note 9. *Derivatives* to the Consolidated Financial Statements. During the years ended December 31, 2025 and 2024, we recognized net realized losses of less than $0.1 million and $0.5 million, respectively, and an unrealized gain of $2.9 million and an unrealized loss of $0.2 million, respectively, or a total net derivative gain of $2.9 million and a total net derivative loss of $0.7 million, respectively. Derivative gains for 2025 are a result of the increase in the price of Dated Brent crude oil over the initial strike price per barrel of the option over the year ended December 31, 2025. Our derivative instruments currently cover a portion of our production through March 2027 for oil and through December 2026 for gas. As part of our Canada Asset Divestment, the purchaser under the Canada APA assumed our hedge contracts associated with gas production volumes from our Canada operating segment.

Impairment loss on assets held for sale for the year ended December 31, 2025 of $67.2 million was attributable to recorded impairments to the carrying value of proved and unproved oil and gas properties for our Canada assets reported as held for sale. The impairment was primarily attributable to a sustained decline in forward strip commodity prices during the period, including decreases in both crude oil and natural gas benchmark pricing. Lower forward pricing reduced expected future net cash flows and negatively impacted market participant valuation assumptions. As a result, estimated proceeds from the planned divestiture declined below the carrying value of the disposal group. There were no assets held for sale as of December 31, 2024.

Interest (expense) income, net increased $4.5 million to an expense of $8.2 million for the year ended December 31, 2025 from an expense of $3.7 million during the same period in 2024. The increase of net interest expense for the year ended December 31, 2025 primarily resulted from an increase in our amortization of debt issue costs, commitment fees incurred and interest incurred on our borrowing under the 2025 RBL Facility, partially offset by interest income. The Company did not draw any amounts under its previous reserve-based credit facility during 2024.

Other (expense) income, net decreased $5.2 million to an expense of $0.6 million for the year ended December 31, 2025 from an expense of $5.8 million for the year ended December 31, 2024. Other (expense) income, net normally consists of foreign currency losses as discussed in Part IV, Item 15., Note 2. *Summary of Significant Accounting Policies* to the Consolidated Financial Statements. However, for the year ended December 31, 2024, other (expense) income, net, also included $3.9 million of transaction costs associated with the Svenska Acquisition.
Income tax expense (benefit) for the year ended December 31, 2025 was an expense of $14.8 million which includes a $13.7 million favorable oil price adjustment as a result of the change in value of the government of Gabon's allocation of Profit Oil between the time it was produced and the time it was taken in-kind. After excluding this impact, income taxes were $28.5 million for the period. For the year ended December 31, 2024, we recorded an income tax expense of $81.3 million which is comprised of $98.9 million of current tax expense and a deferred tax benefit of $17.6 million. The current tax expense in both periods is primarily attributable to our operations in Gabon, Egypt, Canada and Cote d'Ivoire. The income tax expense is lower in 2025 than the income tax expense in 2024 period as a result of lower revenues. See Part IV, Item 15., Note 7. *Income Taxes* to the Consolidated Financial Statements for further discussion.

CAPITAL RESOURCES AND LIQUIDITY

Capital Expenditures

During 2025, we had accrual basis expenditures attributable to operations of $236.4 million, that includes $61.7 million for Gabon, $28.8 million for Egypt, $1.6 million for Canada, $143.2 million for Cote d'Ivoire, $0.6 million for Equatorial Guinea and $0.5 million for the corporate offices, compared to $109.4 million for 2024. Capital expenditures in 2025 were attributable to expenditures primarily related to the new wells drilled as part of the drilling campaign in Egypt, the Phase Three drilling in Gabon, as well as expenditures associated with the refurbishment of the FPSO in Côte d'Ivoire. During the same period in 2024, our cash spending primarily related to the Svenska acquisition as well as payments for the 2024 drilling campaigns in both Egypt and Canada.

Recent Operational Updates

Gabon

The Company's Phase Three Drilling Program in Gabon commenced in the fourth quarter of 2025 with the drilling of the Etame 15H-ST1 development well in the 1V block of Etame in December 2025. The well was completed and placed on production in January 2026 confirming expectations from the pilot well results. Although the West Etame exploration well (ET-14P) encountered 10 meters of high quality sands, the target zone was water-bearing. The lower portion of the well will be plugged and abandoned but the well bore will be utilized and sidetracked in the upper portion of the well to drill the ET-14H development well in the Main Fault Block of Etame. Operations are expected to be completed in April.

After completing our program at the Etame platform, we expect to move the drill rig to the SEENT and Ebouri platforms where we have several wells and workovers planned to enhance production and potentially add reserves.

In July 2025, the Company performed planned, staged shutdowns of the Gabon platforms to perform safety inspections and necessary maintenance to increase the integrity and reliability of the assets. This is the first full field maintenance shutdown that the Company has performed since the new Floating Storage and Offloading vessel ("FSO") was brought online in 2022. All fields were successfully brought back online and the planned turnaround was completed on budget and with no safety or environmental incidents.

The BWE Consortium initiated its 3D seismic campaign across the Niosi and Guduma blocks in November 2025 and such campaign was completed in January 2026. The seismic acquisition was executed and satisfies the minimum commitments under the terms of the Niosi PSC as well as to inform the decision on proceeding into the second exploration period for the Guduma Block.

Egypt

The drilling campaign in Egypt began in December 2024 and continued throughout 2025. During 2025, we drilled a total of 16 wells in the Eastern Dessert, which included 16 development wells. In December 2025, we started drilling an additional well which was completed in January 2026. All wells drilled in the Eastern Dessert successfully achieved their target. Additionally, continuous well interventions, workovers and optimization activities were carried out in 2025 to enhance production levels. We also drilled one exploration well in South Ghazalat which was later determined to be not commercially viable.

Cote d'Ivoire

In connection with the planned dry dock refurbishment, the Baobab FPSO ceased hydrocarbon production on January 31, 2025, with the final crude oil lifting in February 2025. The vessel departed the field in late March 2025 for Dubai for the refurbishment work, which was completed in February 2026. The Baobab FPSO has commenced mobilization back to Cote d'Ivoire and is expected to return to offshore Cote d'Ivoire by late March 2026, with field production expected to restart during the second quarter of 2026. A rig has been secured for the planned development drilling program which is expected to begin during the fourth quarter of 2026 after the FPSO returns to service. The drilling campaign is expected to bring meaningful additions to production from the main Baobab field in CI-40.

In February 2026, the Company became the operator with a 60% working interest in the Kossipo field on the CI-40 Block with a field development plan to be completed in the second half of 2026.

In March 2025, the Company farmed into the CI-705 block offshore Côte d'Ivoire as the operator with a 70% working interest and a 100% paying interest though a commercial carry arrangement with two other parties. The CI-705 block is located in the Ivorian Basin, west of the Company's CI-40 Block, where the Baobab and Kossipo oil fields are located.

Canada

In 2025, the Company decided to defer the drilling of additional wells in Canada based on a reassessment of capital allocation priorities across the portfolio and to ensure that investment is directed toward projects with the highest expected returns. As discussed above, in early 2026, the Company completely exited its Canadian oil and gas operations. Please see above under "*Divestment of Non-Core Assets*," for further discussion on the sale of the Canada operating assets.

Equatorial Guinea

We own a 60% working interest in an undeveloped portion of Block P offshore Equatorial Guinea where we are the designated operator. We have an existing plan of development of the Venus field discovery on Block P, which focuses on key areas of drilling evaluations, facilities design, market inquiries and metocean review. In the second quarter of 2025, the Company completed the initial Front End Engineering and Design study that confirmed the viability of the development concept and is currently evaluating alternative technical solutions which may deliver enhanced economic value.

Commodity Price Hedging

The price we receive for our crude oil significantly influences our revenue, profitability, liquidity, access to capital and prospects for future growth. Crude oil commodities and, therefore their prices can be subject to wide fluctuations in response to relatively minor changes in supply and demand. We believe these prices will likely continue to be volatile in the future.

Due to the inherent volatility in crude oil prices, we use commodity derivative instruments such as swaps to hedge price risk associated with a portion of our anticipated crude oil production. These instruments allow us to reduce, but not eliminate, the potential effects of variability in cash flow from operations due to fluctuations in commodity prices. The instruments provide only partial protection against declines in crude oil prices and may limit our potential gains from future increases in prices. None of these instruments are used for trading purposes. We do not speculate on commodity prices but rather attempt to hedge physical production by individual hydrocarbon product in order to protect returns. The counterparty to our derivative swap transactions was a major oil company’s trading subsidiary, and our costless collars are with Glencore. We have not designated any of our derivative contracts as fair value or cash flow hedges. The changes in fair value of the contracts are included in the consolidated statements of operations and other comprehensive income (loss). We record such derivative instruments as assets or liabilities in the consolidated balance sheet. We do not anticipate any substantial changes in our hedging policy.

Please see Part IV, Item 15., Note 9. *Derivatives* in our Consolidated Financial Statements for more information on the related hedges.

Cash on Hand

At December 31, 2025 and 2024, we had unrestricted cash of $58.9 million and $82.6 million, respectively, which as of certain dates, exceeded Federal Deposit Insurance Corporation insurance limits. We invest cash not required for immediate operational and capital expenditure needs in short-term money market instruments primarily with financial institutions where we determine our credit exposure is negligible. As operator of the Etame Marin block in Gabon, we enter into project-related activities on behalf of our working interest joint venture owners. We generally obtain advances from joint venture owners prior to significant funding commitments. Our cash on hand will be utilized, along with cash generated from operations, to fund our operations.

Capital Resources, Liquidity and Cash Requirements

Our primary source of liquidity has been cash flows from operations and our primary use of cash has been to fund capital expenditures for development activities. We continually monitor the availability of capital resources, including equity and debt financings that could be utilized to meet our future financial obligations, planned capital expenditure activities and liquidity requirements including those to fund opportunistic acquisitions. Our future success in growing proved reserves, production and balancing the long-term development of our assets with a focus on generating attractive corporate-level returns will be highly dependent on the capital resources available to us.

Based on current expectations, we believe we have sufficient liquidity through our existing cash balances, cash flow from operations and our 2025 RBL Facility to support our current cash requirements during the next 12 months and beyond, including the FPSO refurbishment, drilling programs, dividend payments, abandonment funding, as well as transaction expenses and capital and operational costs associated with our business segments' operations. However, our ability to generate sufficient cash flow from operations or fund any potential future acquisitions, consortiums, joint ventures or pay dividends for other similar transactions depends on operating and economic conditions, some of which are beyond our control. If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. We are continuing to evaluate all uses of cash, including opportunistic acquisitions, and whether to pursue growth opportunities and whether such growth opportunities, additional sources of liquidity, including equity and/or debt financings, are appropriate to fund any such growth opportunities.

Merged Concession Agreement

For information on the Merged Concession Agreement, see Part IV, Item 15., Note 11. *Commitments and Contingencies* to the Consolidated Financial Statements.

2025 RBL Facility Agreement and Available Credit

For information on our 2025 Facility Agreement and available credit, see Part IV, Item 15., Note 12. *Debt* to the Consolidated Financial Statements.

Cash Requirements

Our material cash requirements generally consist of the FPSO refurbishment, finance and operating leases, capital projects, dividend payments and abandonment funding, each of which is discussed in further detail below.

Abandonment Funding - Under the terms of the Etame PSC, we have a cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin block. As a result of the PSC Extension, annual funding payments are spread over the periods from 2018 through 2028, under the applicable abandonment study. The amounts paid will be reimbursed through the Cost Account and are non-refundable. In August 2023, an abandonment study was completed which estimated abandonment costs of approximately $77.9 million ($45.9 million, net to Vaalco) on an undiscounted basis. The abandonment estimate was presented to the Gabonese Directorate of Hydrocarbons as required by the PSC. In the first quarter of 2023, the Directorate of Hydrocarbons in Gabon approved a $26.6 million ($15.6 million, net to Vaalco) abandonment funding payment associated with the FPSO retirement. The Company received payment of $15.6 million in March 2023. No additional activity was noted in the abandonment funding account through the end of 2025. At December 31, 2025, the balance of the abandonment fund was $10.7 million ($6.3 million, net to Vaalco) on an undiscounted basis. The annual payments will be adjusted based on revisions in the abandonment estimate. This cash funding is reflected under “Other noncurrent assets” in the “Abandonment funding” line item of the consolidated balance sheets. The Company is working with the Directorate of Hydrocarbons in Gabon to establish a payment schedule to resume funding of the abandonment fund. Future changes to the anticipated abandonment cost estimate could change the asset retirement obligation and the amount of future abandonment funding payments.

Capital Projects - In December 2024, the Company secured a rig for the Phase Three drilling campaign at Etame and has spud the first infill well in December 2025. The Phase Three drilling campaign includes several wells and workovers planned to enhance production, lower costs and potentially add reserves. In Egypt, we anticipate to continue our drilling and completion campaign, as well as recompletion activities in 2026. In CDI, a rig has been secured for the Phase 5 planned development drilling program, which is expected to begin during the fourth quarter of 2026 following the FPSO’s returns to service.

Leases - We are a party to several operating and financing lease arrangements, including operating leases, which may include corporate offices, drilling rigs, rental of marine vessels and helicopter, warehouse and storage facilities, equipment and financing lease agreements for the FSO, and equipment and vehicles used in operations. The annual costs of these leases are significant to us. For further information see Part IV, Item 15., Note 13. *Leases* to our Consolidated Financial Statements.

Merged Concession Agreement - Under the Merged Concession Agreement, a total of $65.0 million of modernization payments were to be made to EGPC over a period of six years from February 1, 2020 (the “Merged Concession Effective Date”). As of December 31, 2025, all modernization payments had been fully settled either through actual cash payments or through the issuance of credit against receivables owed from EGPC. We also have minimum financial work commitments of $50.0 million per each five-year period of the primary development term, commencing on the Merged Concession Effective Date. As of December 31, 2025, the $50.0 million of financial work commitments had been delivered to EGPC.

FPSO Maintenance – The Baobab FPSO arrived at the shipyard in Dubai ahead of schedule in mid-May 2025 for planned maintenance and upgrades. The FPSO refurbishment work was completed in February 2026 and the Baobab FPSO has commenced its mobilization back to Cote d’Ivoire. The FPSO is expected to return to service in the second quarter of 2026.

BWE Consortium – We are a member of the BWE Consortium that was awarded the licenses for the Niosi Marin and the Guduma Marin exploration blocks in Gabon. These licenses are covered by PSCs entered into with the Gabonese Government. These PSCs will have two exploration periods totaling eight years which may be extended by an additional two more years. During the first exploration period, the joint owners intend to reprocess existing seismic and carry out a 3-D seismic campaign on these two blocks and have also committed to drilling exploration wells on both blocks. The first exploration period ends in May 2026. In the event the BWE Consortium elects to enter the second exploration period, the BWE Consortium will be committed to drilling at least another one exploration well on each of the awarded blocks. Under the terms of the BWE Consortium PSC, the Company holds a 37.5% non-operating working interest in these licenses.

Dividend Policy – Our Board of Directors adopted a quarterly cash dividend policy of an expected $0.0625 per common share per quarter, which commenced in the first quarter of 2023. Payment of future dividends, if any, will be at the discretion of the Board of Directors after taking into account various factors, including current financial condition, the tax impact of repatriating cash, operating results and current and anticipated cash needs.

Drilling Rig Commitment - The Company entered into a bareboat charter agreement (the "Bareboat Charter") in late 2024 to charter the drilling rig for its Phase Three drilling campaign in Gabon. Pursuant to the Bareboat Charter, the Company also entered into a service agreement with a third party for the drilling rig maintenance and operations. The Bareboat Charter commenced with the mobilization of the drilling rig towards the Company's first well in November 2025 and has a noncancellable period of 300 days plus five single well options. The Bareboat Charter stipulates fixed day rates and other variable payments.

Cash Flows

Our cash flows for the years ended December 31, 2025 and 2024 are as follows:

	Year Ended December 31,		
	2025	2024	**Increase (Decrease) in 2025 over 2024**
		(in thousands)	
Net cash provided by operating activities before changes in operating assets and liabilities	**$ 117,263**	$ 184,312	$ (67,049)
Net change in operating assets and liabilities	**95,404**	(70,594)	165,998
Net cash provided by operating activities	**212,667**	113,718	98,949
Net cash used in investing activities	**(255,890)**	(102,119)	(153,771)
Net cash provided by (used in) in financing activities	**12,377**	(43,048)	55,425
Effects of exchange rate changes on cash	**83**	(3)	86
Net change in cash, cash equivalents and restricted cash	**$ (30,763)**	$ (31,452)	$ 689

The $98.9 million increase in net cash provided by operating activities during the year ended December 31, 2025 compared to the year ended December 31, 2024, was driven primarily by changes in operating assets and liabilities during the period. The net increase in changes provided by operating assets and liabilities of $166.0 million for the year ended December 31, 2025 compared to the same period of 2024 was related to an increase in cash provided by trade receivable and Egypt receivables and other, net (collectively $121.7 million). In addition, cash provided by operating assets and liabilities increased due to an increase in accounts payable and accrued liabilities and other balances of $82.9 million. Partially offsetting these changes was a decrease in cash provided on a decrease in foreign income taxes receivable (payable) of $45.1 million.

The $153.8 million increase in net cash used in investing activities during the year ended December 31, 2025 was due to the increase in cash capital spending in 2025. In 2025 capital spending was primarily attributable to costs associated with the development drilling programs in Egypt, as well as maintenance, project costs and long lead items for Gabon and Côte d'Ivoire. In 2024 capital spending was primarily attributable to the costs associated with the recompletion and drilling program. In addition, the Company used $40.2 million in cash for the acquisition of Svenska which is offset by the cash received from Svenska in the amount of $41.0 million.

Net cash provided by financing activities during the year ended December 31, 2025 included $60.0 million in proceeds from borrowings under our new 2025 RBL Facility partially offset by $26.5 million for dividend distributions, $0.7 million for treasury stock repurchases as a result of tax withholding on options exercised and on vested restricted stock, $7.1 million for deferred financing costs related to our new 2025 RBL Facility and $13.3 million of principal payments on our finance leases. For the year ended December 31, 2024, cash used in financing activities included $26.2 million for dividend distributions, $6.8 million for treasury stock repurchased under our stock repurchase plan, and $10.5 million of principal payments on our finance leases partially offset by $0.4 million in proceeds from options exercised.

Regulatory and Joint Interest Audits

We are subject to periodic routine audits by various government agencies, including audits of our petroleum Cost Account, customs, taxes and other operational matters, as well as audits by other members of the contractor group under our joint operating agreements. See Part IV, Item 15., Note 11. *Commitment and Contingencies* to the Consolidated Financial Statements for further discussion.

CRITICAL ACCOUNTING ESTIMATES

The preparation of Financial Statements in accordance with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the Financial Statements and the reported amounts of revenues and expenses during the respective reporting periods. Accounting estimates are considered to be critical if (1) the nature of the estimates and assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change, and (2) the impact of the estimates and assumptions on financial condition or operating performance is material. Actual results could differ from the estimates and assumptions used. Further, in some cases, GAAP allows more than one alternative accounting method for reporting. In those cases, our reported results of operations would be different should we employ an alternative accounting method. See Part IV, Item 15., Note 2. *Summary of Significant Accounting Policies* to the Consolidated Financial Statements for our accounting policy elections.

Asset Retirement Obligations

The Company has significant obligations to remove tangible equipment and restore land or seabed at the end of oil and gas production operations. Estimating the future plugging and abandonment costs requires management to make estimates and judgments inherent in the present value calculation of the future obligation. These include ultimate plugging and abandonment costs, inflation factors, credit adjusted discount rates, and timing of settlement and changes in the legal, regulatory, environmental and political environments.

We account for asset retirement obligations as required by ASC 410 — Asset Retirement and Environmental Obligations. Under these standards, the fair value of a liability for an asset retirement obligation is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. If a reasonable estimate of fair value cannot be made in the period the asset retirement obligation is incurred, the liability is recognized when a reasonable estimate of fair value can be made. If a tangible long-lived asset with an existing asset retirement obligation is acquired, a liability for that obligation is recognized at the asset's acquisition or in service date. In addition, a liability for the fair value of a conditional asset retirement obligation is recorded if the fair value of the liability can be reasonably estimated. We capitalize the asset retirement costs by increasing the carrying amount of the related long-lived asset by the same amount as the liability. We record increases in the discounted abandonment liability resulting from the passage of time in depletion, depreciation and amortization in the consolidated statement of operations and comprehensive income (loss). To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation liability, a corresponding adjustment is made to the oil and natural gas property balance.

Income Taxes

Our annual tax provision is based on expected taxable income, statutory rates and tax planning opportunities available to us in the various jurisdictions in which we operate. The determination and evaluation of our annual tax provision and tax positions involves the interpretation of the tax laws in the various jurisdictions in which we operate and requires significant judgment and the use of estimates and assumptions regarding significant future events such as the amount, timing and character of income, deductions and tax credits. Changes in tax laws, regulations, agreements and tax treaties or our level of operations or profitability in each jurisdiction would impact our tax liability in any given year. We also operate in foreign jurisdictions where the tax laws relating to the crude oil, natural gas and NGLs industry are open to interpretation, which could potentially result in tax authorities asserting additional tax liabilities. While our income tax provision (benefit) is based on the best information available at the time, a number of years may elapse before the ultimate tax liabilities in the various jurisdictions are determined.

Judgment is required in determining whether deferred tax assets will be realized in full or in part. Management assesses the available positive and negative evidence to estimate if existing deferred tax assets will be utilized. When it is estimated to be more-likely-than-not that all or some portion of the deferred tax assets will not be realized, a valuation allowance must be established for the amount of the deferred tax assets that are estimated to not be realizable. Factors considered include earnings generated in previous periods, forecasted earnings, the expiration period of carryovers, and overall economic conditions of the industry. As of December 31, 2025, we had deferred tax assets of $310.0 million primarily attributable to Canada and U.S. basis differences in fixed assets, foreign tax credit carryforwards, and foreign net operating loss carryforwards. A valuation allowance of $203.6 million has been established against the deferred tax assets as of December 31, 2025, as management has concluded that it was more-likely-than-not that only some portion of the deferred tax assets would be realized. In future periods, we may determine that it is more-likely-than-not that all or some portion of the deferred tax assets will be realized, and in such period all or a portion of this valuation allowance may be reversed as the evidence warrants.

In certain jurisdictions, we may deem the likelihood of realizing deferred tax assets as remote where we expect that, due to the structure of operations and applicable law, the operations in such jurisdictions will not give rise to future tax consequences. Should our expectations change regarding the expected future tax consequences, we may be required to record additional deferred taxes that could have a material effect on our consolidated financial position and results of operations. For further discussion, see Part IV, Item 15., Note 7. *Income Taxes* to the Consolidated Financial Statements.

Oil and Gas Accounting Reserves Determination

The successful efforts method of accounting depends on the estimated reserves we believe are recoverable from our crude oil, natural gas and NGLs reserves. The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data.

To estimate the economically recoverable crude oil, natural gas and NGLs reserves and related future net cash flows, we incorporate many factors and assumptions including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future crude oil, natural gas and NGLs differentials;
- assumed effects of regulation by governmental agencies; and
- future development and operating costs.

We believe our assumptions are reasonable based on the information available to us at the time we prepare our estimates. However, these estimates may change substantially going forward as additional data from development activities and production performance becomes available and as economic conditions impacting crude oil, natural gas and NGLs prices and costs change.

Management is responsible for estimating the quantities of proved crude oil, natural gas and NGLs reserves and for preparing related disclosures. Estimates and related disclosures are prepared in accordance with SEC requirements and generally accepted industry practices in the U.S. as prescribed by the Society of Petroleum Engineers. Reserve estimates are independently evaluated at least annually by NSAI, who is our independent qualified reserves engineer. Prior to 2025, reserves estimates for Canada were evaluated by GLJ. Equatorial Guinea will receive a Management Case Report.

Our Board of Directors has established the Technical & Reserves Committee with the authority, responsibility and primary purpose of assisting the Board of Directors in its oversight responsibilities relating to evaluating and reporting on oil and gas reserves. The Technical & Reserves Committee, to the extent it deems necessary or appropriate, will oversee (i) annual review of oil and gas reserves, (ii) procedures for evaluating and reporting oil and gas producing activities, and (iii) compliance with applicable regulatory and securities laws relating to the preparation and disclosure of information with respect to oil and gas reserves and shall consult with the Audit Committee on such matters relating to oil and gas reserves which impact our financial statements.

Our senior executives and reserve engineers oversee the preparation of our crude oil, natural gas and NGLs reserves and related disclosures by our appointed independent reserve engineers. The Technical & Reserves Committee and senior management meet with the reserve engineers periodically to review the reserves process and results, and to confirm that the independent reserve engineers have had access to sufficient information, including the nature and satisfactory resolution of any material differences of opinion between us and the independent reserve engineers.

Reserves estimates are critical to many of our accounting estimates, including:

- determining whether or not an exploratory well has found economically producible reserves;
- calculating our unit-of-production depletion rates. Proved developed reserves estimates are used to determine rates that are applied to each unit-of-production in calculating our depletion expense; and
- assessing, when necessary, our crude oil, natural gas and NGLs assets for impairment using undiscounted future cash flows based on management's estimates. If impairment is indicated, discounted values will be used to determine the fair value of the assets. The critical estimates used to assess impairment, including the impact of changes in reserves estimates, are discussed below.

See "*Item 15. Exhibits and Financial Statement Schedules – Supplemental Information on crude oil, natural gas and NGLs Producing Activities (unaudited).*"

Impairment of crude oil, natural gas and NGLs producing properties

We review the crude oil, natural gas and NGLs producing properties for impairment quarterly or whenever events or changes in circumstances indicate that the carrying amount of such properties may not be recoverable. When a crude oil, natural gas and NGLs property's undiscounted estimated future net cash flows are not sufficient to recover its carrying amount, an impairment charge is recorded to reduce the carrying amount of the asset to its fair value. Our assessment involves a high degree of estimation uncertainty as it requires us to make assumptions and apply judgment to estimate undiscounted future net cash flows related to proved and probable reserves. Such assumptions include commodity prices, capital spending, production and abandonment costs and reservoir data. The fair value of the asset is measured using a discounted cash flow model relying primarily on Level 3 inputs to estimate the undiscounted future net cash flows. In addition, we considered risk adjustment factors in our fair value measurement. The undiscounted estimated future net cash flows used in the impairment evaluations at each quarter end are based upon the most recently prepared reserve reports evaluated by independent reserve engineers adjusted to use forecasted prices from the forward strip price curves near each quarter end and adjusted as necessary for drilling and production results. Assets that are not impaired on a held-and-used basis could possibly become impaired if a decision is made to sell such assets. That is, the assets would be impaired if they are classified as held-for-sale and the estimated proceeds from the sale, less costs to sell, are less than the assets' associated carrying values. For further discussion, see Part IV, Item 15., Note 4. *Acquisitions and Divestitures* and Note 8. *Crude Oil, Natural Gas and NGLs Properties and Equipment, Net* to the Consolidated Financial Statements.

Impairment of Unproved Property

We evaluate our undeveloped crude oil, natural gas and NGLs leases for impairment on at least a quarterly basis by considering numerous factors that could include nearby drilling results, seismic interpretations, market values of similar assets, existing contracts and future plans for exploration or development. When undeveloped crude oil, natural gas and NGLs leases are deemed to be impaired, exploration expense is charged. Unproved property costs consist mainly of acquisition costs related to undeveloped acreage in the Etame Marin, Niosi Marin, and Guduma Marin blocks in Gabon, the CI-705 block in Cote d'Ivoire and to Block P in Equatorial Guinea.

Business Combinations

We apply the acquisition method of accounting for business combinations, under which we record the acquired assets and assumed liabilities at fair value and recognize goodwill to the extent the consideration transferred exceeds the fair value of the net assets acquired. To the extent the fair value of the net assets acquired exceeds the consideration transferred, we recognize a bargain purchase gain.

In estimating the fair values of assets acquired and liabilities assumed in a business combination, various assumptions are made. The most significant assumptions relate to the estimated fair values assigned to proved and unproved crude oil, natural gas and NGLs properties. If sufficient market data is not available regarding the fair values of proved and unproved properties, estimates of the fair value of crude oil and gas reserves are prepared. Estimates of future prices to apply to the estimated reserves quantities acquired and estimates of future operating and capital costs are used to estimate future net cash flows. For estimated proved reserves, the future net cash flows are discounted using a market-based discount rate and risk adjustment factors determined appropriate at the time of the acquisition. Estimated deferred taxes are based on available information concerning the tax basis of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

We estimate the fair values of the acquired assets and assumed liabilities as of the date of the acquisition, and our estimates are subject to adjustment through completion, which is in each case within one year of the acquisition date, based on our ongoing assessments of the fair values of property and equipment, intangible assets, other assets and liabilities and our evaluation of tax positions and contingencies.

ACCOUNTING STANDARDS

See Part IV, Item 15., Note 3. *New Accounting Standards* to the Consolidated Financial Statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risks, including the effects of adverse changes in foreign exchange rates and commodity prices as described below.

Foreign Exchange Rate Risk

Our results of operations and financial condition are affected by currency exchange rates. While crude oil sales are denominated in U.S. dollars, portions of our costs in Gabon are denominated in the local currency (the Central African CFA Franc, or XAF), and our VAT receivable as well as certain liabilities in Gabon are also denominated in XAF. A weakening U.S. dollar will have the effect of increasing costs while a strengthening U.S. dollar will have the effect of reducing costs. For our VAT receivable in Gabon, a strengthening U.S. dollar will have the effect of decreasing the value of this receivable resulting in foreign exchange losses, and vice versa. The Gabon local currency is tied to the Euro. The exchange rate between the Euro and the U.S. dollar has historically fluctuated in response to international political conditions, general economic conditions and other factors beyond our control. As of December 31, 2025, we had net monetary liabilities of $113.4 million (XAF 63.2 billion) denominated in XAF. A 10% weakening of the CFA relative to the U.S. dollar would have a $10.3 million increase in the value of these net liabilities. For the year ended December 31, 2025, we had expenditures of approximately $86.4 million denominated in XAF.

Related to our Canadian operations, our currency exchange risk relates primarily to certain cash and cash equivalents, accounts receivable, lease obligations and accounts payable and accrued liabilities denominated in Canadian dollars. We estimate that a 10% increase in the value of the Canadian dollar against the US dollar would increase net earnings for the year ended December 31, 2025 by approximately $0.2 million. Conversely, a 10% decrease in the value of the Canadian dollar against the US dollar would decrease net earnings for the year ended December 31, 2025 by approximately $0.2 million.

We are also exposed to foreign currency exchange risk on cash balances denominated in Egyptian pounds. Some collections of accounts receivable from the Egyptian Government are received in Egyptian pounds, and while we are generally able to use the Egyptian pounds received on accounts payable denominated in Egyptian pounds, there remains foreign currency exchange risk exposure on Egyptian pound cash balances. Using month-end cash balances converted at month-end foreign exchange rates at December 31, 2025, we estimate that a 10% increase in the value of the Egyptian pound against the US dollar would decrease net earnings for the year ended December 31, 2025 by approximately $4.2 million. Conversely, a 10% decrease in the value of the Egyptian pound against the US dollar would increase net earnings for the year ended December 31, 2025 by approximately $3.5 million.

In Cote d'Ivoire, our currency exchange risk also relates primarily to certain cash and cash equivalents, accounts receivable and accounts payable and accrued liabilities denominated in Swedish Krona. We estimate that a 10% decrease in the value of the Swedish Krona against the US dollar would increase the value of the net assets for the year ended December 31, 2025 by approximately $1.8 million. Conversely, a 10% increase in the value of the Swedish Krona against the US dollar would decrease the value of the net liabilities for the year ended December 31, 2025 by approximately $2.2 million.

We do not utilize derivative instruments to manage foreign exchange risk. We maintain nominal balances of British Pounds Sterling to pay in-country costs incurred in operating our London office. Foreign exchange risk on these funds is not considered material.

Commodity Price Risk

Our major market risk exposure continues to be the prices received for our crude oil, natural gas and NGLs production. Sales prices are primarily driven by the prevailing market prices applicable to our production. Market prices for crude oil, natural gas and NGLs have been volatile and unpredictable in recent years, and this volatility may continue. Sustained low crude oil, natural gas and NGLs prices or a presumption of the decreases in crude oil, natural gas and NGLs prices could have a material adverse effect on our financial condition, the carrying value of our proved reserves, our undeveloped leasehold interests and our ability to borrow funds and to obtain additional capital on attractive terms.

Crude oil, natural gas and NGLs properties and equipment are assessed for impairment annually as well as whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company would estimate the fair value of its properties and record an impairment charge for any excess of the carrying amount of the properties over the estimated fair value of the properties. Factors used to estimate fair value may include estimates of proved and probable reserves, estimated future commodity prices, future production estimates, and anticipated capital and operating expenditures, using a commensurate discount rate. In addition, we include risk adjustment factors in our fair value measurement. Unfavorable changes in any of these assumptions could result in a reduction in undiscounted future cash flows and could indicate property impairment. Uncertainties related to the primary assumptions could affect the timing of an impairment. In most cases, the assumption that generates the most variability in undiscounted future net cash flows is future oil and gas prices. We observed a decline in commodity prices during the year ended December 31, 2025 which prompted us to evaluate the recoverability of the carrying value of our assets and whether an other than temporary impairment occurred for certain crude oil, natural gas and NGLs properties and equipment. As a result of these tests, no impairments were recorded during the year ended December 31, 2025 related to our crude oil, natural gas and NGLs producing properties and equipment, excluding properties held for sale; however, certain crude oil, natural gas and NGLs properties and equipment may be at risk for impairment if the estimates of future cash flows decline.

It is also reasonably possible that prolonged low or further decline in commodity prices, negative reserve revisions, changes to the Company's drilling plans in response to lower prices or increases in drilling or operating costs could result in material future impairment charges.

If crude oil sales were to remain constant at the most recent annual sales volumes, a $5 per Bbl decrease in crude oil price would decrease our revenues and operating income or increase our operating loss for the year as follows:

	2025 Sales Volumes (Mbls)	Decrease in Revenues (In Millions)	Decrease in Operating Income (In Millions)
Gabon	2,735	$ 13.7	$ 12.3
Egypt	2,730	$ 13.6	$ 8.1
Cote d'Ivoire	238	$ 1.2	$ 0.6
Canada	667	$ 3.3	$ 2.6
Consolidated	6,370		

With respect to our crude oil sales in Gabon, Egypt and Cote d'Ivoire the price received is based on Dated Brent prices plus or minus a differential. With respect to our crude oil and NGLs sales in Canada, the prices received is based on NYMEX WTI (West Texas Intermediate) prices plus or minus a differential. Natural gas sales are based on Canadian index price that whose price is based, in part, on the NYMEX Henry Hub Natural Gas futures contracts.

Egypt production is shared with the Egyptian government through PSCs. When the price of oil increases, it takes fewer barrels to recover costs (Cost Oil or cost recovery barrels) which are assigned 100% to the Company. The PSCs provide for cost recovery per quarter up to a maximum percentage of total production. Timing differences often exist between the Company's recognition of costs and their recovery as the Company accounts for costs on an accrual basis, whereas cost recovery is determined on a cash basis. If the eligible cost recovery is less than the maximum defined cost recovery, the difference is defined as "excess". In Egypt, depending on the PSCs, our share of excess ranges between 5% and 15%. If the eligible cost recovery exceeds the maximum allowed percentage, the unclaimed cost recovery is carried forward to the next quarter. Typically, maximum Cost Oil ranges from 25% to 40% in Egypt. The balance of the production after maximum cost recovery is shared with the government as Profit Oil. Depending on the contract, the Egyptian government receives 67% to 84% of the Profit Oil. Production sharing splits are set in each contract for the life of the contract. Typically, the government's share of Profit Oil increases when production exceeds pre-set production levels in the respective contracts. During times of high oil prices, the Company may receive less Cost Oil and may receive more Profit Oil. During times of lower oil prices, the Company receives more Cost Oil and may receive less Profit Oil.

Outstanding derivative contracts at December 31, 2025 are as follows:

		Settlement Period			
Instrument	**Index**	**January 2026 - March 2026**	**April 2026 - June 2026**	**July 2026 - September 2026**	**October 2026 - December 2026**
Crude oil:					
Collars	Dated Brent				
Total volumes (Bbls)		400,000	360,000	75,000	—
Weighted average floor price ($/Bbl)		$ 62.29	$ 61.88	$ 65.00	$ —
Weighted average ceiling price ($/Bbl)		$ 68.63	$ 67.95	$ 71.00	$ —
Natural Gas[(a)]:					
Swaps	AECO 7A				
Total volumes (GJs)(b)		225,000	150,000	150,000	50,000
Weighted average fixed price (CAD/GJ)		$ 2.99	$ 2.80	$ 2.80	$ 2.80

(a) Natural gas hedge contracts were assumed by the third-party purchaser upon closing of the sale pursuant to the Canada APA.
(b) One gigajoule (GJ) equals one billion joules (J). A gigajoule of natural gas is approximately 25.5 cubic meters standard conditions.

Subsequent to December 31, 2025, the Company entered into the following additional derivative contracts to cover its future anticipated production:

		Settlement Period				
Instrument	**Index**	**January 2026 - March 2026**	**April 2026 - June 2026**	**July 2026 - September 2026**	**October 2026 - December 2026**	**January 2027 - March 2027**
Crude oil:						
Collars	Dated Brent					
Total volumes (Bbls)		260,000	338,000	702,000	692,000	673,000
Weighted average floor price ($/Bbl)		$ 62.00	$ 64.22	$ 63.72	$ 64.96	$ 64.68
Weighted average ceiling price ($/Bbl)		$ 67.80	$ 70.14	$ 68.49	$ 68.33	$ 72.63
Swaps	Dated Brent					
Total volumes (Bbls)		100,000	—	—	—	—
Weighted average fixed price ($/Bbl)		$ 65.10	$ —	$ —	$ —	$ —

Interest Rate Risk

As of December 31, 2025, our primary exposure to interest rate risk resulted from our outstanding borrowings under our 2025 RBL Facility of $60.0 million. The borrowing accrues interest at a rate of 10.8% per annum which is based on the Term SOFR plus the applicable margin of 6.5% per annum. We currently do not hedge our interest rate exposure. We estimate that a 10% increase in the applicable average interest rates during the time from the date the debt was drawn through December 31, 2025 would have resulted in an increase in interest expense of $0.2 million. There were no outstanding borrowings during the year ended December 31, 2024. Additionally, changes in market interest rates could impact interest costs associated with any future indebtedness.

Item 8. Consolidated Financial Statements and Supplementary Data

The information required here begins on page F-1 as described in "*Item 15. Exhibits and Financial Statement Schedules—Index to Consolidated Financial Information*".

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our principal executive officer ("CEO") and principal financial officer ("CFO"), to allow timely decisions regarding required disclosure. In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management was required to apply its judgment in evaluating and implementing possible controls and procedures. Management, including our CEO and CFO, has evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report on Form 10-K. Based on this evaluation, our CEO and CFO have concluded that the Company's disclosure controls and procedures were effective as of December 31, 2025.

Management's Annual Report on Internal Control Over Financial Reporting

Our management, including our CEO and CFO, is responsible for establishing and maintaining adequate internal control over financial reporting, as that term is defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. Internal control over financial reporting is a process designed under the supervision of our CEO and our CFO, overseen by our Board of Directors and Audit Committee, and effected by management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes using the framework in Internal Control – Integrated Framework (2013), issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO framework"). Such internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate. The Company's management, with participation of the CEO and CFO, under the oversight of our Board of Directors, evaluated the effectiveness of the Company's internal control over financial reporting as of December 31, 2025 using the COSO framework. Based on the evaluation, our management concluded that, the Company's internal control over financial reporting was effective as of December 31, 2025.

Remediation of Prior Material Weaknesses

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of annual or interim financial statements will not be prevented or detected on a timely basis.

As discussed in our Annual Report on Form 10-K for the year ended December 31, 2024, our management concluded that there were material weaknesses in our internal control over financial reporting related to general information technology controls, effectiveness of control environment, risk assessment and design and process-level controls.

In response to the identified material weakness at December 31, 2024, our management, with oversight from our Audit Committee, made the following changes in its financial reporting processes in 2025:

- We strengthened IT controls by adding resources and reallocating staff to improve risk assessment, change management, and IT oversight.
- We enhanced our efforts to design and implement a continuous risk-assessment process to identify and address risks of material misstatement and to ensure controls are properly designed and operating effectively.
- We established and implemented a comprehensive risk assessment process over general information technology controls, which continues to be refined as part of our ongoing monitoring activities.
- We hired a new IT Director and management has reviewed IT general controls with the IT Director to provide visibility into control design and align responsibilities for ongoing monitoring of controls.

After completing our testing of the design and operational effectiveness of these controls, our management concluded that we fully remediated the previously identified material weaknesses as of December 31, 2025.

Our internal controls over financial reporting as of December 31, 2025 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report which is included in Item 8 of this Annual Report. KPMG LLP has provided an attestation report on the Company's internal control over financial reporting which is included in Item 8 of this Annual Report.

Changes in Internal Control over Financial Reporting

Other than as stated above, no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) occurred during the quarter ended December 31, 2025 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

During the quarter ended December 31, 2025, none of the Company's directors or officers (as defined in Rule 16a-1(f) of the Exchange Act) adopted, terminated or modified a Rule 10b5-1 trading arrangement or non-Rule 10b5-1 trading arrangement (as such terms are defined in Item 408 of Regulation S-K of the Securities Act).

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information required by this item will be included in our proxy statement for our 2026 annual meeting, which will be filed with the SEC within 120 days of December 31, 2025, and that is incorporated herein by reference.

Item 11. Executive Compensation

Information required by this item will be included in our proxy statement for our 2026 annual meeting, which will be filed with the SEC within 120 days of December 31, 2025, and that is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by this item under Item 403 of Regulation S-K concerning the security ownership of certain beneficial owners and management will be included in our proxy statement for our 2026 annual meeting, which will be filed with the SEC within 120 days of December 31, 2025, and which is incorporated herein by reference.

The following table provides information as of December 31, 2025 regarding the number of shares of common stock that may be issued under our compensation plans. Please refer to Part IV, Item 15., Note 16. *Stock-based Compensation and Other Benefit Plans* to the Consolidated Financial Statements for additional information on stock-based compensation.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants, and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issues under equity compensation plans (excluding securities reflected in the first column)
Equity compensation plans approved by security holders	1,097,482	$ 5.30	483,624
Total	1,097,482	$ 5.30	483,624

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by this item will be included in our proxy statement for our 2026 annual meeting, which will be filed with the SEC within 120 days of December 31, 2025, and that is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

Information required by this item will be included in our proxy statement for our 2026 annual meeting, which will be filed with the SEC within 120 days of December 31, 2025, and that is incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) 1. The following is an index to the Financial Statements that are filed as part of this Form 10-K.

VAALCO ENERGY, INC. AND SUBSIDIARIES

(a) 2. Other schedules are omitted because they are not required, not applicable or the required information is included in the Financial Statements or notes thereto.

(a) 3. Exhibits:

2.1	Sale and Purchase Agreement, dated as of November 17, 2020, by and between Sasol Gabon S.A. and VAALCO Gabon S.A. (filed as Exhibit 2.1 to the Company's Annual Report on Form 10-K filed on March 9, 2021, and incorporated herein by reference).
2.2**	Arrangement Agreement, dated as of July 13, 2022, by and among VAALCO Energy, Inc., VAALCO Energy Canada ULC and TransGlobe Energy Corporation (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K filed on July 14, 2022 and incorporated herein by reference).
2.3**	Share Purchase Agreement, dated February 29, 2024, by and between VAALCO Energy (Holdings), Inc., Petroswede AB (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K filed on February 29, 2024 and incorporated herein by reference).
3.1	Restated Certificate of Incorporation as amended through May 7, 2014 (filed as Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q filed on November 10, 2014, and incorporated herein by reference).
3.1.1	Certificate of Amendment to Restated Certificate of Incorporation of VAALCO, dated October 14, 2022 (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K filed on October 13, 2022 and incorporated herein by reference).
3.2	Third Amended and Restated Bylaws, dated July 30, 2020 (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K filed on August 4, 2020, and incorporated herein by reference).
3.3	Certificate of Elimination of Series A Junior Participating Preferred Stock of VAALCO Energy, Inc., dated as of December 22, 2015 (filed as Exhibit 3.2 to the Company's Current Report on Form 8-K filed on December 23, 2015, and incorporated herein by reference).
4.1(a)	Description of Securities
10.1	Exploration and Production Sharing Contract, dated July 7, 1995, between the Republic of Gabon and VAALCO Gabon (Etame), Inc. (filed as Exhibit 10.1 to the Company's Annual Report on Form 10-K filed on March 7, 2018, and incorporated herein by reference).
10.2	Addendum No. 1 to Exploration and Production Sharing Contract, dated July 7, 2001, between the Republic of Gabon and VAALCO Gabon (Etame), Inc. (filed as Exhibit 10.2 to the Company's Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.3	Addendum No. 2 to Exploration and Production Sharing Contract, dated July 7, 2006, between the Republic of Gabon and VAALCO Gabon (Etame), Inc. (filed as Exhibit 10.3 to the Company's Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).

10.4	Addendum No. 3 to Exploration and Production Sharing Contract, dated November 26, 2009, between the Republic of Gabon and VAALCO Gabon (Etame), Inc. (filed as Exhibit 10.4 to the Company's Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.5	Addendum No. 4 to Exploration and Production Sharing Contract, dated January 5, 2012, between the Republic of Gabon and VAALCO Gabon (Etame), Inc. (filed as Exhibit 10.5 to the Company's Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.6	Addendum No. 5 to Exploration and Production Sharing Contract, dated April 25, 2016, between the Republic of Gabon and VAALCO Gabon (Etame), Inc. (filed as Exhibit 10.6 to the Company's Annual Report on Form 10-K filed on March 7, 2018, and incorporated herein by reference).
10.7	Addendum No. 6 to Exploration and Production Sharing Contract, dated September 17, 2018, between the Republic of Gabon, VAALCO Gabon S.A., Addax Petroleum Oil & Gas Gabon, Sasol Gabon S.A. and Petroenergy Resources Corporation (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed on November 7, 2018, and incorporated herein by reference).
10.8	Deed of Novation of Trustee and Paying Agent Agreement, dated June 22, 2017, between VAALCO Gabon (Etame), Inc., VAALCO Gabon S.A. and The Bank of New York Mellon, London Branch as the Trustee and Paying Agent and the Account Bank (filed as Exhibit 10.7 to the Company's Annual Report on Form 10-K filed on March 7, 2018, and incorporated herein by reference).
10.9*	VAALCO Energy, Inc. 2014 Long Term Incentive Plan (filed as Appendix A to the Company's Definitive Proxy Statement on Schedule 14A filed on April 17, 2014, and incorporated herein by reference).
10.10*	Form of Restricted Stock Award Agreement under the VAALCO Energy, Inc. 2014 Long Term Incentive Plan (filed as Exhibit 10.20 to the Company's Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.11*	Form of Non statutory Stock Option Agreement under the VAALCO Energy, Inc. 2014 Long Term Incentive Plan (filed as Exhibit 10.21 to the Company's Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.12*	Form of Stock Award Agreement (for Directors) under the VAALCO Energy, Inc. 2014 Long Term Incentive Plan (filed as Exhibit 10.22 to the Company's Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.13*	VAALCO Energy, Inc. 2016 Stock Appreciation Rights Plan (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on March 15, 2016, and incorporated herein by reference).
10.14*	Form of Stock Appreciation Rights Agreement under the VAALCO Energy, Inc. 2016 Stock Appreciation Rights Plan (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed on March 15, 2016, and incorporated herein by reference).
10.15*	Form of Change in Control Agreement (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 8, 2019, and incorporated herein by reference).
10.16*	VAALCO Energy, Inc. 2020 Long Term Incentive Plan (filed as Appendix B to the Company's Definitive Proxy Statement on Schedule 14A filed on April 29, 2020, and incorporated herein by reference).
10.17*	First Amendment to VAALCO Energy, Inc. 2020 Long Term Incentive Plan (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on June 8, 2021, and incorporated herein by reference).
10.18*	Amendment No. 2 to the VAALCO Energy, Inc. 2020 Long-Term Incentive Plan (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on June 6, 2024, and incorporated herein by reference).
10.19*	Form of Restricted Stock Award Agreement (Director) under the VAALCO Energy, Inc. 2020 Long Term Incentive Plan (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed on June 30, 2020, and incorporated herein by reference).
10.20*	Form of Restricted Stock Award Agreement (Employee) under the VAALCO Energy, Inc. 2020 Long Term Incentive Plan (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K filed on June 30, 2020, and incorporated herein by reference).
10.21*	Form of Nonqualified Stock Option Agreement under the VAALCO Energy, Inc. 2020 Long Term Incentive Plan (filed as Exhibit 10.4 to the Company's Current Report on Form 8-K filed on June 30, 2020, and incorporated herein by reference).
10.22*	Employment Agreement, by and between VAALCO Energy, Inc. and George Maxwell, effective as of April 19, 2021 (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed on April 12, 2021, and incorporated herein by reference).
10.22.1*	Amendment No. 1 to Employment Agreement, by and between VAALCO Energy, Inc. and George Maxwell, effective as of January 27, 2022 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on January 28, 2022, and incorporated herein by reference).
10.22.2*	Amendment No. 2 to Employment Agreement, by and between VAALCO Energy, Inc. and George Maxwell, effective as of November 23, 2022 (filed as Exhibit 10.21.2 to the Company's Annual Report on Form 10-K filed on April 6, 2023, and incorporated herein by reference).

10.22.3*	Amendment No. 3 to Executive Employment, effective June 6, 2024, by and between VAALCO Energy, Inc. and George W. M. Maxwell (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed on August 9, 2024, and incorporated herein by reference).
10.23*	Employment Agreement, by and between VAALCO Energy, Inc. and Ronald Bain, effective as of June 21, 2021 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on June 22, 2021, and incorporated herein by reference).
10.23.1*	Amendment No. 1 to Employment Agreement, effective as of January 27, 2022, by and between VAALCO Energy, Inc. and Ronald Bain (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed on January 28, 2022, and incorporated herein by reference).
10.23.2*	Amendment No. 2 to Employment Agreement, effective as of November 23, 2022, by and between VAALCO Energy, Inc. and Ronald Bain (filed as Exhibit 10.23.2 to the Company's Annual Report on Form 10-K filed on April 6, 2023, and incorporated herein by reference).
10.23.3*	Amendment No. 3 to Executive Employment, effective June 6, 2024, by and between VAALCO Energy, Inc. and Ronald Y. Bain (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed on August 9, 2024, and incorporated herein by reference).
10.24*	TransGlobe Energy Corporation Amended and Restated Deferred Share Unit Plan (filed as Exhibit 10.24 to the Company's Annual Report on Form 10-K filed on April 6, 2023, and incorporated herein by reference).
10.25**	Bareboat Charter, by and between VAALCO Energy, Inc. and World Carrier Offshore Services Corp, dated August 31, 2021 (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed on November 3, 2021, and incorporated by reference herein).
10.25.1**	Deed of Novation and Amendment to Bareboat Charter, by and between VAALCO Gabon SA, World Carrier Offshore Services Corp. and Ocean Cloud Navigation Inc., dated as of November 15, 2022 (filed as Exhibit 10.25.1 to the Company's Annual Report on Form 10-K filed on April 6, 2023, and incorporated herein by reference).
10.25.2**	Second Amendment to Bareboat Charter, by and between VAALCO Gabon SA and Ocean Cloud Navigation Inc., dated as of March 22, 2023 (filed as Exhibit 10.25.2 to the Company's Annual Report on Form 10-K filed on April 6, 2023, and incorporated herein by reference).
10.26**	Operating Agreement, by and between VAALCO Energy, Inc. and World Carrier Offshore Services Corp, dated August 31, 2021 (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed on November 3, 2021, and incorporated herein by reference).
10.26.1**	Deed of Novation and Amendment to Operating Agreement, by and between VAALCO Gabon SA, World Carrier Offshore Services Corp. and Atlantic Energy Logistics SASU, dated as of November 15, 2022 (filed as Exhibit 10.26.1 to the Company's Annual Report on Form 10-K filed on April 6, 2023, and incorporated herein by reference).
10.27	Deed of Guarantee and Indemnity, by and between VAALCO Energy, Inc. and World Carrier Offshore Services Corp., dated August 31, 2021 (filed as Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q filed on November 3, 2021, and incorporated herein by reference).
10.27.1	Deed of Novation and Amendment to Deed of Guarantee and Indemnity, by and between VAALCO Energy, Inc., World Carrier Offshore Services Corp. and Ocean Cloud Navigation Inc., dated as of November 15, 2022.(filed as Exhibit 10.27.1 to the Company's Annual Report on Form 10-K filed on April 6, 2023, and incorporated herein by reference).
10.28	Deed of Guarantee and Indemnity, by and between VAALCO Energy, Inc. and World Carrier Offshore Services Corp., dated August 31, 2021 (filed as Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q filed on November 3, 2021, and incorporated herein by reference)
10.28.1**	Deed of Novation and Amendment to Deed of Guarantee and Indemnity, by and between VAALCO Energy, Inc., World Carrier Offshore Services Corp. and Atlantic Energy Logistics SASU, dated as of November 15, 2022 (filed as Exhibit 10.28.1 to the Company's Annual Report on Form 10-K filed on April 6, 2023, and incorporated herein by reference).
10.29	Concession Agreement for Petroleum Exploration, Development and Exploitation between The Arab Republic of Egypt and the Egyptian General Petroleum Corporation and TransGlobe West Bakr Inc. and TransGlobe West Gharib Inc. and TG NW Gharib Inc. in Merged Development Areas of West Bakr Area, West Gharib Area, Northwest Gharib Onshore Area, Eastern Desert, A.R.E. (furnished as Exhibit 1 to TransGlobe Energy Corporation's Report of Foreign Private Issuer on Form 6-k furnished on March 24, 2022, and incorporated herein by reference)
10.30**	Crude Oil Sale and Marketing Agreement, by and between VAALCO Gabon S.A. and Glencore Energy UK Ltd., dated May 20, 2022 (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed on August 10, 2022, and incorporated herein by reference).
10.31*	Amended and Restated Executive Employment, effective April 18, 2024, by and between VAALCO Energy, Inc. and Thor Pruckl (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed on May 8, 2024, and incorporated herein by reference).

10.31.1*	Amendment No. 1 to Executive Employment, effective June 6, 2024, by and between VAALCO Energy, Inc. and Thor Pruckl (filed as Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q filed on August 9, 2024, and incorporated herein by reference).
10.32*	Executive Employment Agreement, effective January 18, 2024, by and between VAALCO Energy, Inc. and Matthew Powers (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed on May 8, 2024, and incorporated herein by reference).
10.32.1*	Amendment No. 1 to Executive Employment, effective June 6, 2024, by and between VAALCO Energy, Inc. and Matthew Powers (filed as Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q filed on August 9, 2024, and incorporated herein by reference).
10.33**	Borrowing Base Facility Agreement by and among VAALCO Energy, Inc., as the Original Borrower, The Financial Institutions listed in Schedule 1 thereto, as the Original Lenders, The Standard Bank of South Africa Limited, Isle of Man Branch, as the Mandated Lead Arranger, and The Standard Bank of South Africa Limited, as the Agent, dated March 4, 2025 (filed as Exhibit 10.34 to the Company's Annual Report on Form 10-K filed on March 17, 2025 and incorporated herein by reference).
10.34*	Form of 2025 Restricted Stock Award Agreement under the VAALCO Energy, Inc. 2020 Long Term Incentive Plan (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed on August 11, 2025, and incorporated herein by reference).
10.35**	Asset Purchase Agreement, by and among VAALCO Energy Canada, Inc., Petrus Resources Corp., and, solely for the purposes of Section 9.7 therein, Petrus Resources LTD., dated February 4, 2026. (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on February 10, 2026, and incorporated herein by reference).
19.1	Insider Trading Policy (filed as Exhibit 19.1 to the Company's Annual Report on Form 10-K filed on March 17, 2025 and incorporated herein by reference).
21.1(a)	List of subsidiaries of the Company.
23.1(a)	Consent of KPMG LLP
23.2(a)	Consent of Netherland, Sewell & Associates, Inc. — Independent Petroleum Engineers.
31.1(a)	Sarbanes-Oxley Section 302 certification of Principal Executive Officer.
31.2(a)	Sarbanes-Oxley Section 302 certification of Principal Financial Officer.
32.1(b)	Sarbanes-Oxley Section 906 certification of Principal Executive Officer.
32.2(b)	Sarbanes-Oxley Section 906 certification of Principal Financial Officer.
97.1	Clawback Policy (filed as Exhibit 97.1 to the Company's Annual Report on Form 10-K filed on March 17, 2025 and incorporated herein by reference).
99.1(a)	Report of Netherland, Sewell & Associates, Inc. (International Properties)- Egypt
99.2(a)	Report of Netherland, Sewell & Associates, Inc. (International Properties) - Gabon
99.3(a)	Report of Netherland, Sewell & Associates, Inc. (International Properties) - Cote d'Ivoire
99.4(a)	Report of Netherland, Sewell & Associates, Inc. (International Properties) - Canada
101.INS(a)	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH(a)	Inline XBRL Taxonomy Schema Document.
101.CAL(a)	Inline XBRL Calculation Linkbase Document.
101.DEF(a)	Inline XBRL Definition Linkbase Document.
101.LAB(a)	Inline XBRL Label Linkbase Document.
101.PRE(a)	Inline XBRL Presentation Linkbase Document.
104(a)	Cover Page Interactive Data File (formatted as Inline XBRL and Contained in Exhibit 101).

(a) Filed herewith
(b) Furnished herewith
* Management contract or compensatory plan or arrangement
** Information in this exhibit has been omitted pursuant to Item 601 of Regulation S-K.

Item 16. Form 10-K Summary

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

VAALCO ENERGY, INC.
(Registrant)

By /s/ George W.M. Maxwell
George W.M. Maxwell
Chief Executive Officer

Dated March 16, 2026

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on the 16th day of March 2026, by the following persons on behalf of the registrant and in the capacities indicated.

Signature		Title
By:	/s/ George Maxwell George Maxwell	Chief Executive Officer (Principal Executive Officer) and Director
By:	/s/ Ron Bain Ron Bain	Chief Financial Officer (Principal Financial Officer)
By:	/s/ Lynn Willis Lynn Willis	Chief Accounting Officer (Principal Accounting Officer)
By:	/s/ Andrew L. Fawthrop Andrew L. Fawthrop	Chairman of the Board and Director
By:	/s/ Catherine L. Stubbs Catherine L. Stubbs	Director
By:	/s/ Fabrice Nze-Bekale Fabrice Nze-Bekale	Director
By:	/s/ Edward LaFehr Edward LaFehr	Director

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors
VAALCO Energy, Inc.:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of VAALCO Energy, Inc. and subsidiaries (the Company) as of December 31, 2025 and 2024, the related consolidated statements of operations and comprehensive income (loss), shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2025, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2025, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 16, 2026 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Assessment of the impact of estimated crude oil, natural gas and natural gas liquids (NGLs) proved reserves on depletion expense related to crude oil, natural gas and NGLs properties

As discussed in Note 2 to the consolidated financial statements, the Company determines depletion of crude oil, natural gas and NGLs properties on a block basis under the unit-of-production method based upon estimates of proved reserves. For the year ended December 31, 2025, the Company recorded depreciation, depletion and amortization expense of $110 million. The estimation of proved reserves requires the expertise of reserve engineer specialists, who take into consideration future production, future operating and capital costs, and historical crude oil, natural gas and NGLs prices inclusive of price differentials. The Company engages independent reserve engineer specialists to estimate proved reserves, which are an input to the calculation of depletion.

We identified the assessment of the impact of estimated crude oil, natural gas and NGLs proved reserves on depletion expense related to crude oil, natural gas and NGLs properties as a critical audit matter. Changes in assumptions used to estimate the proved reserves could have had a significant impact on depletion expense. Complex auditor judgment was required in evaluating the Company's estimates of proved reserves. Specifically, auditor judgment was required to evaluate the assumptions used by the Company related to future production and future operating and capital costs.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls over the Company's depletion process, including controls over the estimation of proved reserves. We evaluated the professional qualifications and knowledge, skills, and ability of the Company's internal reserve engineers and the independent reserve engineer specialists and the independent reserve engineering firm engaged by the Company. We evaluated the relationship of the independent reserve engineer specialists and independent reserve engineering firm to the Company. We analyzed and assessed the determination of depletion expense for compliance with industry and regulatory standards. We assessed compliance of the methodology used by the Company's independent reserve engineer specialists to estimate proved reserves with industry and regulatory standards. We read and considered the report of the Company's independent reserve engineering firm in connection with our evaluation of the Company's proved reserve estimates. We compared future production to historical production rates. We evaluated the future operating and capital costs by comparing them to historical costs.

Evaluation of the recoverability of certain crude oil, natural gas and NGLs producing properties

As discussed in Note 2 to the consolidated financial statements, the Company performs impairment tests with respect to its crude oil, natural gas and NGLs producing properties on an asset group basis whenever events or changes in circumstances indicate that the carrying amount of such properties may not be recoverable. If there is an indication the carrying amount of the crude oil, natural gas and NGLs producing properties may not be recovered, the Company estimates the undiscounted future net cash flows and compares this to the carrying value of the crude oil and natural gas property. If the sum of the expected undiscounted future net cash flows from the use of the asset and its eventual disposition is less than the carrying amount of the asset, an impairment charge is recorded based on the fair value of the asset. Estimated future net cash flows are based on assumptions such as forecasted production, forecasted commodity prices inclusive of price differentials, and development and operating costs. As a result of these tests, no impairments were recorded during the year ended December 31, 2025 for the Company's crude oil, natural gas and NGLs producing properties, excluding properties held for sale.

We identified the evaluation of the estimate of undiscounted future net cash flows from the related proved and probable reserves, used to assess the recoverability of certain crude oil and natural gas producing properties, as a critical audit matter. Subjective auditor judgment was required in the evaluation of the estimate of undiscounted future net cash flows from the related proved and probable reserves, due to (1) uncertainty associated with future commodity prices and estimated future production, (2) judgment inherent in forecasting development and operating costs, and (3) subjectivity in determining the risk adjustment factors associated with reserve volumes.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls over the Company’s impairment of crude oil, natural gas and NGLs producing properties process, including controls over the Company’s proved and probable reserve estimation process. We evaluated the professional qualifications and knowledge, skills, and ability of the Company’s internal reserve engineers, the independent reserve engineer specialists, and the independent reserve engineering firm engaged by the Company. We evaluated the relationships of the independent reserve engineer specialists and independent reserve engineering firm to the Company. We analyzed and assessed the estimate of undiscounted future net cash flows from the related proved and probable reserves for compliance with industry and regulatory standards. We assessed compliance of the methodology used by the Company’s independent reserve engineer specialists to estimate proved and probable reserves with industry and regulatory standards. We read and considered the report of the Company’s independent reserve engineering firm in connection with our evaluation of the Company’s proved and probable reserves estimate. We evaluated the Company’s undiscounted future net cash flows analysis related to forecasted production, and development and operating costs by comparing to historical results and future development plans. We evaluated the relevant price differentials used by the Company by comparing them to historical results. We involved valuation professionals with specialized skills and knowledge, who assisted in evaluating the forecasted commodity prices, by comparing them to an independently developed range of forward price estimates using data from analysts and other industry sources, and the risk adjustment factors associated with reserve volumes, by comparing them to third party publications of risk adjustment factors utilized by market participants.

/s/ KPMG LLP

We have served as the Company’s auditor since 2023.

Houston, Texas
March 16, 2026

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors
VAALCO Energy, Inc.:

Opinion on Internal Control Over Financial Reporting

We have audited VAALCO Energy, Inc. and subsidiaries' (the Company) internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2025 and 2024, the related consolidated statements of operations and comprehensive income (loss), shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2025, and the related notes (collectively, the consolidated financial statements), and our report dated March 16, 2026 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ KPMG LLP

Houston, Texas
March 16, 2026

VAALCO ENERGY, INC. AND SUBSIDIARIES CONSOLIDATED BALANCE SHEETS

(in thousands, except share amounts)	December 31, 2025	December 31, 2024
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 58,900**	$ 82,650
Restricted cash	**136**	143
Receivables:		
Trade, net of allowances for credit loss and other of $0.0 million and $0.2 million, respectively	**39,924**	94,778
Accounts with joint venture owners, net of allowance for credit losses of $2.7 million and $1.5 million, respectively	**5,420**	179
Egypt receivables and other	**2,277**	35,763
Crude oil inventory	**1,774**	9,441
Prepayments and other	**24,370**	14,973
Current assets held for sale	**179**	—
Total current assets	**132,980**	237,927
Crude oil, natural gas and NGLs properties and equipment, net	**586,095**	538,103
Other noncurrent assets:		
Restricted cash	**1,659**	8,665
Value added tax and other receivables, net of allowances for credit loss and other of $0.0 million and $0.8 million, respectively	**7,149**	10,094
Right of use operating lease assets	**16,596**	17,254
Right of use finance lease assets	**68,615**	79,849
Deferred tax assets	**54,825**	55,581
Abandonment funding	**6,268**	6,268
Other long-term assets	**7,362**	1,209
Noncurrent assets held for sale	**31,826**	—
Total assets	**$ 913,375**	$ 954,950
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	**$ 44,661**	$ 11,756
Accounts with joint venture owners	**3,193**	3,324
Accrued liabilities and other	**106,444**	107,710
Operating lease liabilities - current portion	**5,744**	3,512
Finance lease liabilities - current portion	**12,119**	13,383
Foreign income taxes payable	**19,656**	42,043
Current liabilities held for sale	**183**	—
Total current liabilities	**192,000**	181,728
Asset retirement obligations	**78,406**	78,592
Operating lease liabilities - net of current portion	**11,183**	13,903
Finance lease liabilities - net of current portion	**57,256**	67,377
Deferred tax liabilities	**63,630**	93,904
Long-term debt	**60,000**	—
Other long-term liabilities	**—**	17,863
Noncurrent liabilities held for sale	**7,403**	—
Total liabilities	**469,878**	453,367
Commitments and contingencies (Note 11)		
Shareholders' equity:		
Preferred stock, $25 par value; 500,000 shares authorized, none issued	**—**	—
Common stock, $0.10 par value; 160,000,000 shares authorized, 123,017,656 and 122,304,124 shares issued, 104,258,253 and 103,743,163 shares outstanding, respectively	**12,302**	12,230
Additional paid-in capital	**368,536**	362,578
Accumulated other comprehensive loss	**(498)**	(4,962)
Less treasury stock, 18,759,403 and 18,560,931 shares, respectively, at cost	**(78,733)**	(78,024)
Retained earnings	**141,890**	209,761
Total shareholders' equity	**443,497**	501,583
Total liabilities and shareholders' equity	**$ 913,375**	$ 954,950

See notes to consolidated financial statements.

VAALCO ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2025	**2024**	**2023**
	(in thousands, except per share amounts)		
Revenues:			
Crude oil, natural gas and natural gas liquids sales	**$ 359,272**	$ 478,988	$ 455,066
Operating costs and expenses:			
Production expense	**158,177**	163,500	153,157
FPSO demobilization and other costs	**—**	—	7,484
Exploration expense	**8,914**	48	1,965
Depreciation, depletion and amortization	**109,978**	143,034	115,302
Impairment loss on assets held for sale	**67,224**	—	—
General and administrative expense	**33,089**	29,684	23,840
Credit losses (recovery) and other	**106**	6,304	(4,906)
Total operating costs and expenses	**377,488**	342,570	296,842
Other operating income (expense), net	**(2,391)**	78	433
Operating income (loss)	**(20,607)**	136,496	158,657
Other income (expense):			
Derivative instruments gain (loss), net	**2,876**	(745)	232
Interest expense, net	**(8,243)**	(3,732)	(6,452)
Bargain purchase gain and measurement period adjustment	**—**	13,532	(1,412)
Other expense, net	**(595)**	(5,754)	(894)
Total other income (expense), net	**(5,962)**	3,301	(8,526)
Income (loss) before income taxes	**(26,569)**	139,797	150,131
Income tax expense	**14,822**	81,307	89,777
Net income (loss)	**$ (41,391)**	$ 58,490	$ 60,354
Other comprehensive income (loss)			
Currency translation adjustments	**4,464**	(7,842)	1,701
Comprehensive income (loss)	**$ (36,927)**	$ 50,648	$ 62,055
Basic net income (loss) per share:			
Net income (loss) per share	**$ (0.40)**	$ 0.56	$ 0.56
Basic weighted average shares outstanding	**104,055**	103,669	106,376
Diluted net income (loss) per share:			
Net income (loss) per share	**$ (0.40)**	$ 0.56	$ 0.56
Diluted weighted average shares outstanding	**104,055**	103,747	106,555

See notes to consolidated financial statements

VAALCO ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common Shares Issued	Treasury Shares	Common Stock	Additional Paid-In Capital	Accumulated Other Comprehensive Loss	Treasury Stock	Retained Earnings	Total
				(in thousands)				
Balance at January 1, 2023	119,483	(11,630)	$ 11,948	$ 353,606	$ 1,179	$ (47,652)	$ 147,024	$ 466,105
Shares issued - stock-based compensation	1,915	—	192	482	—	—	—	674
Stock-based compensation expense	—	—	—	3,410	—	—	—	3,410
Treasury stock	—	(5,421)	—	—	—	(23,570)	—	(23,570)
Dividend distributions	—	—	—	—	—		(26,772)	(26,772)
Cumulative effect of adjustment upon adoption of ASU 2016-13 on January 1, 2023	—	—	—	—	—	—	(3,120)	(3,120)
Other comprehensive income					1,701	—	—	1,701
Net income	—	—	—	—	—	—	60,354	60,354
Balance at December 31, 2023	121,398	(17,051)	$ 12,140	$ 357,498	$ 2,880	$ (71,222)	$ 177,486	$ 478,782
Shares issued - stock-based compensation	906	—	90	357	—	—	—	447
Stock-based compensation expense	—	—	—	4,723	—	—	—	4,723
Treasury stock	—	(1,510)	—	—	—	(6,802)	—	(6,802)
Dividend distributions	—	—	—	—	—	—	(26,215)	(26,215)
Other comprehensive loss	—	—	—	—	(7,842)	—	—	(7,842)
Net income	—	—	—	—	—	—	58,490	58,490
Balance at December 31, 2024	122,304	(18,561)	$ 12,230	$ 362,578	$ (4,962)	$ (78,024)	$ 209,761	$ 501,583
Shares issued - stock-based compensation	714	—	72	(72)	—	—	—	—
Stock-based compensation expense	—	—	—	6,030	—	—	—	6,030
Treasury stock	—	(198)	—	—	—	(709)	—	(709)
Dividend distributions	—	—	—	—	—	—	(26,480)	(26,480)
Other comprehensive income	—	—	—	—	4,464	—	—	4,464
Net income (loss)	—	—	—	—	—	—	(41,391)	(41,391)
Balance at December 31, 2025	**123,018**	**(18,759)**	**$ 12,302**	**$ 368,536**	**$ (498)**	**$ (78,733)**	**$ 141,890**	**$ 443,497**

See notes to consolidated financial statements.

VAALCO ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2025	**2024**	**2023**
		(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	**$ (41,391)**	$ 58,490	$ 60,354
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	**109,978**	143,034	115,302
Bargain purchase gain and measurement period adjustment	**—**	(13,532)	1,412
Impairment loss on assets held for sale	**67,224**	—	—
Non-cash exploration expense	**2,409**	48	1,841
Deferred taxes	**(29,427)**	(16,785)	(2,864)
Stock-based compensation	**6,211**	4,281	2,945
Derivative instruments loss, net	**(2,876)**	745	(232)
Cash settlements paid on matured derivative contracts, net	**(48)**	(453)	(127)
Cash settlements paid on asset retirement obligations	**(225)**	(368)	(6,747)
Credit losses and other	**(164)**	6,346	7,650
Equipment and other expensed in operations	**5,572**	2,505	3,196
Change in operating assets and liabilities:			
Trade receivables, net	**45,012**	(49,890)	6,723
Accounts with joint venture owners, net	**47**	(757)	19,571
Egypt receivables and other, net	**32,427**	5,644	14,802
Crude oil inventory	**7,667**	7,488	1,387
Prepayments and other	**(11,697)**	(4,817)	4,743
Value added tax and other receivables	**7,042**	(7,110)	2,427
Other long-term assets	**1,161**	2,869	3,830
Accounts payable	**50,907**	(13,198)	(28,102)
Foreign income taxes receivable (payable)	**(22,456)**	22,682	22,030
Accrued liabilities and other	**(14,706)**	(33,504)	(6,544)
Net cash provided by operating activities	**212,667**	113,718	223,597
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property and equipment expenditures, including exploration expense	**(252,856)**	(102,996)	(97,223)
Acquisition of crude oil and natural gas properties	**(3,034)**	877	—
Net cash used in investing activities	**(255,890)**	(102,119)	(97,223)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from the issuances of common stock	**—**	447	673
Proceeds from borrowings	**60,000**	—	—
Dividend distribution	**(26,480)**	(26,216)	(26,772)
Treasury shares	**(709)**	(6,802)	(23,570)
Deferred financing costs	**(7,145)**	—	—
Payments of finance lease	**(13,289)**	(10,477)	(7,150)
Net cash used in in financing activities	**12,377**	(43,048)	(56,819)
Effects of exchange rate changes on cash	**83**	(3)	(153)
NET CHANGE IN CASH, CASH EQUIVALENTS AND RESTRICTED CASH	**(30,763)**	(31,452)	69,402
CASH, CASH EQUIVALENTS AND RESTRICTED CASH AT BEGINNING OF PERIOD	**97,726**	129,178	59,776
CASH, CASH EQUIVALENTS AND RESTRICTED CASH AT END OF PERIOD	**$ 66,963**	$ 97,726	$ 129,178

See notes to consolidated financial statements.

VAALCO ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS SUPPLEMENTAL DISCLOSURES

	Year Ended December 31,		
	2025	**2024**	**2023**
		(in thousands)	
Supplemental disclosure of cash flow information:			
Income taxes paid in-kind with crude oil	**$ 33,714**	$ 37,469	$ 32,776
Interest paid, net of amounts capitalized	**$ 6,637**	$ 6,714	$ 9,122
Supplemental disclosure of non-cash investing and financing activities:			
Property and equipment additions incurred but not paid at end of period	**$ 8,190**	$ 9,479	$ 14,137
Recognition of right-of-use operating lease assets and liabilities	**$ 3,343**	$ 17,649	$ 2,582
Recognition of right-of-use finance lease assets and liabilities	**$ 2,372**	$ —	$ 7,875
Asset retirement obligations adjustments	**$ 85**	$ 27,424	$ 2,487

See notes to consolidated financial statements.

1. ORGANIZATION

VAALCO Energy, Inc. (together with its consolidated subsidiaries "we", "us", "our", "VAALCO" or the "Company") is a Houston, Texas-based independent energy company engaged in the acquisition, exploration, development and production of crude oil, natural gas and NGLs properties. We have a diversified African-focused portfolio of production development and exploration assets located in Gabon, Egypt, Cote d'Ivoire, Equatorial Guinea, Nigeria, as well as, prior to the Canada Asset Divestment (defined below), producing properties in Canada.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of consolidation **–** The accompanying consolidated financial statements ("Financial Statements") include the accounts of the Company and its wholly owned subsidiaries. Investments in unincorporated joint ventures and undivided interests in certain operating and non-operating assets are consolidated on a pro rata basis. All intercompany transactions within the consolidated group have been eliminated in consolidation.

Use of estimates **–** The preparation of the Financial Statements in conformity with generally accepted accounting principles in the U.S. ("GAAP") requires estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the Financial Statements and the reported amounts of revenues and expenses during the respective reporting periods. The Financial Statements include amounts that are based on management's best estimates and judgments. Actual results could differ from those estimates.

Estimates of crude oil, natural gas and NGLs reserves used to estimate depletion expense and impairment charges, as well as to estimate the fair value of assets and liabilities acquired in business combinations, require significant judgments and are generally less precise than other estimates made in connection with financial disclosures. Due to inherent uncertainties and the limited nature of data, estimates are imprecise and subject to change over time as additional information becomes available.

Cash and cash equivalents – Cash and cash equivalents includes deposits and funds invested in highly liquid instruments with original maturities of three months or less at the date of purchase. The Company maintains its cash accounts in financial institutions that are insured by the Federal Deposit Insurance Corporation. From time to time, cash balances may exceed the insured amounts, however, the Company has not experienced any losses in such accounts and does not believe it is exposed to any significant credit risks associated with cash and cash equivalents.

Restricted cash and abandonment funding **–** Restricted cash includes cash that is contractually restricted. Restricted cash is classified as a current or non-current asset based on its designated purpose and estimated timing of usage. As of December 31, 2025, the balance in current restricted cash is for employee-related payroll withholdings, while the long-term restricted cash account represents the funding requirement for the debt service reserve account ("DSRA") under the 2025 RBL Facility. The DSRA required balance is calculated based on the aggregate amount of scheduled principal payable by the Company and the amount of interest payable outstanding under the 2025 RBL Facility. As of December 31, 2024, the balance in current restricted cash is for an escrow amount representing bank guarantees for customs clearance in Gabon and employee-related payroll withholdings, while the long-term restricted cash includes the balance for charter payment escrow for the FPSO offshore Gabon. In addition, the long-term account also includes an $8.9 million balance for the settlement of a tax audit related to the Svenska Acquisition with a corresponding accrued tax settlement liability recorded and included in Other long-term liabilities in the Consolidated Balance Sheet.

In the first quarter of 2023, the Directorate of Hydrocarbons in Gabon approved a $26.6 million ($15.6 million, net to VAALCO) abandonment funding payment associated with the FPSO retirement. The Company received payment of $15.6 million in March 2023. The remaining balance of the abandonment fund was unchanged during 2025.

The Company invests restricted and excess cash in readily redeemable money market funds. The following table provides a reconciliation of cash, cash equivalents, and restricted cash reported within the consolidated balance sheets to the amounts shown in the consolidated statements of cash flows.

	As of December 31,	
	2025	**2024**
	(in thousands)	
Cash and cash equivalents	**$ 58,900**	$ 82,650
Restricted cash - current	**136**	143
Restricted cash - non-current	**1,659**	8,665
Abandonment funding	**6,268**	6,268
Total cash, cash equivalents and restricted cash	**$ 66,963**	$ 97,726

Trade, net – The Company's trade accounts receivable results from sales of crude oil, natural gas and NGLs. For credit losses associated with accounts with trade receivables, see allowance for credit losses and other below.

Accounts with joint venture owners, net – Accounts with joint venture owners represent the excess of charges billed over cash calls paid by the joint venture owners for exploration, development and production expenditures made by the Company as an operator. Joint owner receivables are secured through cash calls and other mechanisms for collection under the terms of the joint operating agreements. For credit loss and other allowances associated with accounts with joint venture owners, see allowance for credit loss and other below.

Egypt receivables and other, net – As of the Merged Concession Effective Date, an effective date adjustment was owed to the Company for the difference in the historic commercial terms and the revised commercial terms applied against the production since the Merged Concession Effective Date (as defined herein) (the "Effective Date Adjustment"). The Company recognized a receivable of $67.5 million for the Effective Date Adjustment as of October 2022, based on historical realized prices (the "Backdated Receivable"). The Backdated Receivable was fully settled as of March 31, 2025.

For credit losses associated with Egypt receivables and other, net, see allowance for credit losses and other below.

Value added tax and other receivables, net – The Company incurs receivables from the government of Gabon for reimbursable Value-Added Tax ("VAT").

As of December 31, 2025 and 2024*,* the outstanding VAT receivable balance was approximately $1.1 million and $2.8 million, net to VAALCO, respectively. The receivable amount, net of allowances, is reported as a non-current asset in the "Value added tax and other receivables" line item in the consolidated balance sheets. Because both the VAT receivable and the related allowances are denominated in XAF, the exchange rate revaluation of these balances into U.S. dollars at the end of each reporting period also has an impact on the Company's results of operations. Such foreign currency gains (losses) are reported separately in the "Other expense, net" line item of the consolidated statements of operations and comprehensive income. For the allowance associated with VAT, see allowance for credit losses and other below.

Allowance for credit losses and other – On January 1, 2023*,* the Company adopted Accounting Standards Update *2016-13,* Financial Instruments—Credit Losses ("*ASU 2016-13*"). ASU *2016-13* requires an entity to measure credit losses of certain financial assets, including trade receivables, utilizing a methodology that reflects expected credit losses and requires consideration of a broader range of reasonable and supportable information to form credit loss estimates. All other amounts previously disclosed as allowances for bad debt were transferred to allowances for credit loss and other.

The Company estimates the current expected credit loss and other allowances based primarily using either an aging analysis or discounted cash flow methodology that incorporates consideration of current and future conditions that could impact its counterparties' credit quality and liquidity. Uncollectible receivables are written off when a settlement is reached for an amount that is less than the outstanding historical balance or when the Company has determined that the balance will *not* be collected.

The Company has identified the following types of financial assets that are within the scope of ASU *2016-13:*

- Trade, net;

- Accounts with joint venture owners, net;
- Egypt receivables and other, net; and
- Loans to employees.

During the years ended December 31, 2025 and 2024, the Company recognized $0.1 million and $7.7 million in credit loss and other allowances, respectively, mainly due to VAT receivables and receivables from joint venture partners.

The following table provides an analysis of the change in the aggregate credit loss and other allowances:

	Year Ended December 31,	
	2025	2024
	(in thousands)	
Allowance for credit losses and other		
Balance at beginning of period	**$ (2,554)**	$ (6,029)
Credit losses and other	**(1,126)**	(6,304)
Credit recoveries and other	**1,028**	(1,421)
Reversal of allowance resulting from the settlement of the related receivable	**—**	11,200
Balance at end of period	**$ (2,652)**	$ (2,554)

Crude oil inventory – Crude oil inventories are carried at the lower of cost or net realizable value. In Gabon and Cote d'Ivoire, inventories represent the Company's share of crude oil produced and stored on the FSO and the FPSO but unsold at the end of each period. In Egypt, inventory consists of the Company's entitlement crude oil barrels not yet sold.

Prepayments and other – Included in "Prepayments and other" line item of the Company's December 31, 2025 and 2024 consolidated balance sheet are the following assets:

	2025	2024
	(in thousands)	
Egypt advances to contractors	**$ 5,485**	$ 3,665
Prepaid fixed asset progress payments	**3,747**	9
Deposits	**3,292**	2,933
Derivatives	**3,053**	119
Employee loans and advances	**2,398**	1,430
Prepaid royalties	**285**	3,089
Other prepayments	**6,110**	3,728
Total prepayments and other	**$ 24,370**	$ 14,973

Crude oil, natural gas and NGLs properties and equipment, net – The Company uses the successful efforts method of accounting for crude oil, natural gas and NGLs producing activities.

- ***Capitalization*** – Costs of successful wells, development dry holes and leases containing productive reserves are capitalized and amortized on a unit-of-production basis over the life of the related reserves. Other exploration costs, including dry exploration well costs, geological and geophysical expenses applicable to undeveloped leaseholds, leasehold expiration costs and delay rentals, are expensed as incurred. The costs of exploratory wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. Cost incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) sufficient progress in assessing the reserves and the economic and operating viability of the project has been made. The status of suspended well costs is monitored continuously and reviewed quarterly. Due to the capital-intensive nature and the geographical characteristics of certain projects, it may take an extended period of time to evaluate the future potential of an exploration project and the economics associated with making a determination of its commercial viability. Costs of seismic studies that are utilized in development drilling within an area of proved reserves are capitalized as development costs. Interest expense is capitalized for qualifying assets under construction. Capitalized interest costs are included in Crude oil, natural gas and NGLs properties and equipment, net.

- ***Capitalized equipment, spare parts and other*** – Capitalized equipment, spare parts and other represents the costs incurred in purchasing and bringing the inventory to its present location and condition and is based on purchase costs calculated on weighted average cost basis, including transportation costs. Inventory is classified as long term when the Company expects to utilize the inventory beyond the normal operating cycle.

- ***Depreciation, depletion and amortization*** – Depletion of wells, platforms, and other production facilities are calculated on a block basis under the unit-of-production method based upon estimates of total proved developed reserves. Depletion of leasehold acquisition costs are provided on a block basis under the unit-of-production method based upon estimates of total proved reserves. Support equipment (other than equipment inventory) and leasehold improvements related to crude oil, natural gas and NGLs producing activities, as well as property, plant and equipment unrelated to crude oil, natural gas and NGLs producing activities, are recorded at cost and depreciated on a straight-line basis over the estimated useful lives of the assets, which are typically five years for office and miscellaneous equipment and five to seven years for leasehold improvements.

- ***Unproved Property Cost*** – Significant unproved properties are assessed individually for impairment and when events or circumstances indicate that the carrying value of property may not be recovered, the capitalized costs of the related properties would be expensed. The unproved property costs are not subject to depreciation, depletion and amortization, until they are classified as proved properties.

- ***Impairment*** – The Company reviews the crude oil, natural gas and NGLs properties and equipment, net for impairment on a block basis whenever events or changes in circumstances indicate that the carrying amount of such properties may not be recoverable. If the sum of the expected undiscounted future cash flows from the use of the asset and its eventual disposition is less than the carrying amount of the asset, an impairment charge is recorded based on the fair value of the asset. This may occur if the block contains lower than anticipated reserves or periods of sustained declines in commodity prices. The fair value measurement used in the impairment test is generally calculated with a discounted cash flow model using several Level 3 inputs that are based upon estimates, the most significant of which is the estimate of net proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond the Company's control. Reserve engineering is a subjective process of estimating underground accumulations of crude oil, natural gas and NGLs that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of crude oil, natural gas and NGLs that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future crude oil, natural gas and NGLs sales prices may all differ from those assumed in these estimates. Long-lived assets that are held for sale are evaluated for possible impairment by comparing the carrying value of the asset with its fair value less the cost to sell. If the net book value exceeds the fair value less cost to sell, the asset is considered impaired and adjusted to the lower value.

  Capitalized equipment inventory is reviewed regularly for obsolescence. During the year ended December 31, 2025, we recorded an inventory write-down of $2.4 million for estimated obsolete inventory as well as inventory whose carrying value is in excess of net realizable value and the related expense is included in the "Other operating income (expense), net" line item in the Consolidated Statements of Operations and Comprehensive Income (Loss).

  When undeveloped crude oil, natural gas and NGLs leases are deemed to be impaired, exploration expense is charged. Unproved property costs consist of acquisition costs related to unproved property costs in the Etame Marin block in Gabon, Canada, Egypt and in Block P in Equatorial Guinea.

- ***Assets and Liabilities Held for Sale*** – The Company classifies disposal groups as held for sale in the period in which all of the following criteria are met: (1) management, having the authority to approve the action, commits to a plan to sell the disposal group; (2) the disposal group is available for immediate sale in its present condition subject only to terms that are usual and customary for sales of such disposal groups; (3) an active program to locate a buyer or buyers and other actions required to complete the plan to sell the disposal group have been initiated; (4) the sale of the disposal group is probable, and transfer of the disposal group is expected to qualify for recognition as a completed sale, within one year, except if events or circumstances beyond the Company's control extend the period of time required to sell the disposal group beyond one year; (5) the disposal group is being actively marketed for sale at a price that is reasonable in relation to its current fair value; and (6) actions required to complete the plan indicate that it is unlikely that significant changes to the plan will be made or that the plan will be withdrawn.

A disposal group that is classified as held for sale is initially measured at the lower of its carrying amount or fair value less any costs to sell. Any loss resulting from this measurement is recognized in the period in which the held for sale criteria are met. Subsequent changes in the fair value of a disposal group less any costs to sell are reported as an adjustment to the carrying amount of the disposal group, as long as the new carrying amount does not exceed the carrying amount of the asset at the time it was initially classified as held for sale. Depreciation, depletion and amortization expense is not recorded on assets to be divested once they are classified as held for sale. In the initial period in which the disposal group meets the criteria to be classified as held for sale, the assets and liabilities of the disposal group are separately presented as assets held for sale and liabilities held for sale, respectively, in the Consolidated Balance Sheets.

When items of crude oil, natural gas and NGLs properties and equipment are sold or otherwise disposed of, any gains or losses are reported in net income. Gains on the disposal of crude oil, natural gas and NGLs properties and equipment are recognized when earned, which is generally at the time of closing. If a loss on disposal is expected, such losses are recognized when the assets are classified as held for sale.

Lease commitments – At inception, contracts are reviewed to determine whether an agreement contains a lease as defined under Accounting Standards Codification (“ASC”) 842*, Leases*. If a lease is identified within the contract, a determination is made whether the lease qualifies as an operating or financing lease. Regardless of the type of lease, the initial measurement of the lease results in recording a right of use (“ROU”) asset and a lease liability at the present value of the future lease payments.

Asset retirement obligations (“ARO”) – The Company has legal obligations to remove tangible equipment and restore land or seabed at the end of crude oil, natural gas and NGLs production operations. The removal and restoration obligations are primarily associated with plugging and abandoning wells, removing and disposing of all or a portion of onshore or offshore crude oil, natural gas and NGLs platforms, and capping pipelines. Estimating the future restoration and removal costs requires management to make estimates and judgments. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety, and public relations considerations.

A liability for ARO is recognized in the period in which the legal obligations are incurred if a reasonable estimate of fair value can be made. The ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with crude oil, natural gas and NGLs properties and equipment, net. The Company uses current retirement costs to estimate the expected cash outflows for retirement obligations. Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental, and political environments. Initial recording of the ARO liability is offset by the corresponding capitalization of asset retirement cost recorded to crude oil, natural gas and NGLs properties and equipment, net. To the extent these or other assumptions change after initial recognition of the liability, the fair value estimate is revised and the recognized liability adjusted, with a corresponding adjustment made to the related capitalized asset retirement cost or through a charged to earnings, as appropriate. Depreciation of capitalized asset retirement costs and accretion of asset retirement obligations are recorded over time. Depreciation is determined on a units-of-production basis for crude oil, natural gas and NGLs properties and equipment, net production facilities, while accretion escalates over the lives of the assets to reach the expected settlement value. Where there is a downward revision to the ARO that exceeds the net book value of the related asset, the corresponding adjustment is limited to the amount of the net book value of the asset and the remaining amount is recognized as a gain.

Revenue recognition – The Company’s revenues are derived from contracts with customers. Royalties are considered to be part of the price of the sale transaction and are therefore presented as a reduction to revenues. Revenues associated with the sale of crude oil, natural gas and NGLs are measured based on the consideration specified in contracts with customers.

Revenues from contracts with customers are recognized when the Company satisfies a performance obligation by transferring a good or service to a customer. A good or service is transferred when the customer obtains control of the good or service. The transfer of control of oil, natural gas and NGLs usually coincides with title passing to the customer and the customer taking physical possession. The Company mainly satisfies its performance obligations at a point in time. Sales and delivery costs associated with certain sales are netted against revenue in accordance with the Company’s policy regarding classification of these type of expenses. The Company has utilized the practical expedient in ASC Topic 606-10-50-14(a), which states that the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation.

Revenues associated with the sales of the Company's crude oil, natural gas, condensates and natural gas liquids ("NGLs") are recognized by reference to actual volumes sold and quoted market prices in active markets for crude oil, natural gas, condensates and NGLs, adjusted according to specific terms and conditions as applicable per the sales contracts. Revenue is measured at the fair value of the consideration received or receivable.

Major maintenance activities – Costs for major maintenance are expensed in the period incurred and can include the costs of workovers of existing wells, contractor repair services, materials and supplies, equipment rentals and labor costs.

Stock-based compensation – The Company measures the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award on the date of the grant. The grant date fair value for options or stock appreciation rights ("SARs") is estimated using either the Black-Scholes or Monte Carlo method depending on the complexity of the terms of the awards granted. The SARs fair value is estimated at the grant date and remeasured at each subsequent reporting date until exercised, forfeited or cancelled.

Black-Scholes and Monte Carlo models employ assumptions, based on management's best estimates at the time of grant, which impact the calculation of fair value and ultimately, the amount of expense that is recognized over the life of the stock options or SAR award. These models use the following inputs: (i) the quoted market price of the Company's common stock on the valuation date, (ii) the maximum stock price appreciation that an employee may receive, (iii) the expected term that is based on the contractual term, (iv) the expected volatility that is based on the historical volatility of the Company's stock for the length of time corresponding to the expected term of the option or SAR award, (v) the expected dividend yield that is based on the anticipated dividend payments and (vi) the risk-free interest rate that is based on the U.S. treasury yield curve in effect as of the reporting date for the length of time corresponding to the expected term of the option or SAR award.

For restricted stock awards, the grant date fair value is determined using the market value of the common stock on the date of grant.

The stock-based compensation expense for equity awards is recognized over the period that services are provided. For awards considered liabilities under US GAAP, awards are measured at fair value on the grant date and remeasured at fair value until the award is settled.

Legal Contingencies – We are subject to legal proceedings, claims, and liabilities that arise in the ordinary course of business. We accrue losses associated with legal claims when such losses are probable and reasonably estimable. If we determine that a loss is probable and cannot estimate a specific amount for that loss but can estimate a range of loss, the best estimate within the range is accrued. If no amount within the range is a better estimate than any other, the minimum amount of the range is accrued. Estimates are adjusted as additional information becomes available or circumstances change. Legal defense costs associated with loss contingencies are expensed in the period incurred.

Foreign currency transactions – The U.S. dollar is the functional currency of the Company's foreign operating subsidiaries except for Canada which has a functional currency of the Canadian dollar. When the Company's subsidiaries' functional currency is the US dollar, gains and losses on foreign currency transactions are included in income. When the Company's subsidiaries functional currency is the local currency, not the US dollar, the cumulative effects of translating the balance sheet accounts from the functional currency into the U.S. dollar at current exchange rates are included in accumulated other comprehensive income (loss). The Company recognized losses on foreign currency transactions of $0.7 million in 2025, $1.8 million in 2024 and $0.9 million in 2023.

Income taxes – The tax provision is based on expected taxable income, statutory rates and tax planning opportunities available to the Company in the various jurisdictions in which the Company operates. The determination and evaluation of the annual tax provision and tax positions involves the interpretation of the tax laws in the various jurisdictions in which the Company operates and requires significant judgment and the use of estimates and assumptions regarding significant future events such as the amount, timing and character of income, deductions and tax credits. Changes in tax laws, regulations, agreements and tax treaties or the level of operations or profitability in each jurisdiction would impact the tax liability in any given year. The Company also operates in foreign jurisdictions where the tax laws relating to the crude oil, natural gas and NGLs industry are open to interpretation, which could potentially result in tax authorities asserting additional tax liabilities. While the income tax provision (benefit) is based on the best information available at the time, a number of years may elapse before the ultimate tax liabilities in the various jurisdictions are determined. The Company also records as income tax expense the increase or decrease in the value of the government's allocation of Profit Oil, which is due to changes in value from the time the allocation is originally produced to the time the allocation is actually lifted.

Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax basis. Deferred tax assets are recognized when it is more likely than not that they will be realized. We periodically assess our deferred tax assets and reduce such assets by a valuation allowance if we deem it is more likely than not that some portion or all of the deferred tax assets will not be realized. Judgment is required in determining whether deferred tax assets will be realized in full or in part. Management assesses the available positive and negative evidence to estimate if existing deferred tax assets will be utilized, and when it is estimated to be more-likely-than-not that all or some portion of specific deferred tax assets, such as net operating loss carry forwards or foreign tax credit carryovers, will not be realized. A valuation allowance must be established for the amount of the deferred tax assets that are estimated to not be realizable. Factors considered are earnings generated in previous periods, forecasted earnings and the expiration period of carryovers.

Derivative instruments and hedging activities – The Company enters into crude oil hedging arrangements from time to time in an effort to mitigate the effects of commodity price volatility and enhance the predictability of cash flows relating to the marketing of a portion of our crude oil production. While these instruments mitigate the cash flow risk of future decreases in commodity prices, they may also curtail benefits from future increases in commodity prices.

The Company records balances resulting from commodity risk management activities in the consolidated balance sheets as either assets or liabilities measured at fair value. The Company has elected not to offset fair value amounts of qualifying derivatives under a master netting arrangement and associated fair value amounts for cash collateral receivables and payables. Gains and losses from the change in fair value of derivative instruments and cash settlements on commodity derivatives are presented in the "Derivative instruments gain (loss), net" line item located within the "Other income (expense)" section of the consolidated statements of operations and comprehensive income (loss).

Fair value – Fair value is defined as the price that would be received to sell an asset or the price paid to transfer a liability in an orderly transaction between market participants at the measurement date. Inputs used in determining fair value are characterized according to a hierarchy that prioritizes those inputs based on the degree to which they are observable. The three input levels of the fair-value hierarchy are as follows:

Level 1 – Inputs are observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the measurement date.

Level 2 – Inputs are observable market-based inputs or unobservable inputs that are corroborated by market data.

Level 3 – Inputs are unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

Nonrecurring Fair Value Measurements – The Company applies fair value measurements to its nonfinancial assets and liabilities measured on a nonrecurring basis, which consist of measurements or remeasurements of impairment of crude oil, natural gas and NGLs properties and equipment, net, asset retirement assets and liabilities and assets acquired and liabilities assumed in a business combination, and assets and liabilities held for sale. The Company uses market-observable prices for assets when comparable transactions can be identified that are similar to the asset being valued. When the Company is required to measure fair value and there is not a market-observable price for the asset or for a similar asset then the cost or income approach is used depending on the quality of information available to support management's assumptions. The cost approach is based on management's best estimate of the current asset replacement cost. The income approach is based on management's best assumptions regarding expectations of future net cash flows. The expected cash flows are discounted using a commensurate risk-adjusted discount rate. Such evaluations involve significant judgment, and the results are based on expected future events or conditions such as sales prices, estimates of future oil and gas production or throughput, development and operating costs and the timing thereof, economic and regulatory climates and other factors, most of which are often outside of management's control. However, assumptions used to reflect a market participant's view of long term prices, costs and other factors and are consistent with assumptions used in the Company's business plans and investment decisions.

Fair value of financial instruments – The Company determines the fair value of our assets and liabilities subject to fair value measurement by using the highest possible "level" of inputs.

	Balance Sheet Line	As of December 31, 2025 Level 1	Level 2	Level 3	Total
		(in thousands)			
Assets					
Derivative asset	Prepayments and other	$ —	$ 3,053	$ —	$ 3,053
		$ —	$ 3,053	$ —	$ 3,053
Liabilities					
Derivative liability	Accrued liabilities and other	$ —	$ 207	$ —	$ 207
		$ —	$ 207	$ —	$ 207

	Balance Sheet Line	As of December 31, 2024 Level 1	Level 2	Level 3	Total
		(in thousands)			
Assets					
Derivative asset	Prepayments and other	$ —	$ 119	$ —	$ 119
Derivative asset, noncurrent	Other long term assets	$ —	$ 1,209	$ —	$ 1,209
		$ —	$ 1,328	$ —	$ 1,328
Liabilities					
Derivative liability	Accrued liabilities and other	$ —	$ 17	$ —	$ 17
		$ —	$ 17	$ —	$ 17

See Note 9. Derivatives for further details of the Company's derivative contracts.

Earnings per Share – Basic earnings per common share is calculated by dividing earnings available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings per common share is calculated by dividing earnings available to common stockholders by the weighted average number of diluted common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities consist of unvested restricted stock awards and stock options using the treasury method. Under the treasury method, the amount of unrecognized compensation expense related to unvested stock-based compensation grants or the proceeds that would be received if the stock options were exercised are assumed to be used to repurchase shares at the average market price. When a loss exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share.

3. NEW ACCOUNTING STANDARDS

Adopted

In December 2023, the Financial Accounting Standards Board ("FASB") issued ASU 2023-09, Income Taxes (Topic 740): Improvements to Income Tax Disclosures. The amendments in this update improve the transparency of income tax disclosures by requiring (1) consistent categories and greater disaggregation of information in the rate reconciliation and (2) income taxes paid disaggregated by jurisdiction. This update improves the effectiveness and comparability of disclosures by requiring disaggregation by jurisdiction of disclosures of pretax income (or loss) and income tax expense (or benefit). This ASU is to be applied on a prospective basis, with retrospective application permitted. The guidance in this update is effective for fiscal years beginning after December 15, 2024. The Company adopted ASU 2023-09 for the year ended December 31, 2025 on a prospective basis. The adoption of ASU 2023-09 required additional income tax disclosures and did not have an impact on the Company's consolidated financial position or results of operations.

Not Yet Adopted

In November 2024, the FASB issued ASU 2024-03, Accounting Standards Update 2024-03, Income Statement-Reporting Comprehensive Income-Expense Disaggregation Disclosures (Subtopic 220-40): Disaggregation of Income Statement Expenses to improve financial reporting by requiring that public business entities disclose additional information about specific expense categories in the notes to financial statements at interim and annual reporting periods. This ASU is effective for annual reporting periods beginning after December 15, 2026, and interim reporting periods beginning after December 15, 2027. Early adoption is permitted. The Company is currently evaluating the impact of adopting this ASU to our notes to the consolidated financial statements and processes.

In July 2025, the FASB issued ASU 2025-05, Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses for Accounts Receivable and Contract Assets. The ASU introduces a practical expedient and, for non-public business entities, an accounting policy election to simplify the application of credit loss guidance to short-term receivables and contract assets by allowing consideration of post-balance-sheet collections. This ASU is effective for annual reporting periods beginning after December 15, 2026, and interim reporting periods within those annual reporting periods. Early adoption is permitted. The Company has elected to not adopt the practical expedient. The Company, when estimating its credit losses, will continue to consider available information that is relevant to its assessment of the collectibility of cash flows, including historical losses, current economic conditions, and reasonable and supportable forecasts. Management will continue to monitor changes in the Company's portfolio, economic conditions, and future guidance issued by the Financial Accounting Standards Board to determine whether election of the practical expedient would be appropriate in future reporting periods.

4. ACQUISITIONS AND DIVESTITURE

Canada Asset Divestment

In December 2025, the Company's Board of Directors approved the sale of the Company's oil and gas properties in Canada. As of December 31, 2025, the assets and liabilities associated with the Canada Asset Divestment (defined below) were classified as held for sale on our Consolidated Balance Sheet. The Canada Asset Divestment does not qualify as a discontinued operation under FASB ASC Topic 205, *Presentation of Financial Statements*, as it does not represent a strategic shift that will have a major effect on the Company's operations or financial results.

Upon classification as held for sale, the Company recorded an impairment loss of $67.2 million to adjust the carrying value of the assets held for sale to their estimated fair value less cost to sell. The impairment loss is presented in the "Impairment loss on assets held for sale" line item in the Consolidated Statements of Operations and Comprehensive Income (Loss). The following table sets forth the carrying value of the assets and liabilities held for sale:

	Balance Sheet Classification	December 31, 2025
		(in thousands)
Current assets (Derivative assets, current)	Current assets held for sale	$ 179
Crude oil, natural gas and NGLs properties and equipment, net	Noncurrent assets held for sale	31,826
Current liabilities (Asset retirement obligation, current)	Current liabilities held for sale	(183)
Asset retirement obligations	Noncurrent liabilities held for sale	(7,403)
Net assets held for sale		**$ 24,419**

As previously discussed, the Company reviews the crude oil, natural gas and NGLs properties and equipment quarterly at each reporting period or whenever events or changes in circumstances indicate that the carrying amount of such properties may not be recoverable. Impairment assessments are performed in connection with the preparation of the financial statements, ensuring that recognized losses reflect conditions as of the reporting date. As further discussed above, the Company determined that the Canada Asset Divestment met the criteria for classification as held for sale as of December 31, 2025. This determination constituted a triggering event requiring an impairment assessment, which was performed concurrently with the Company's periodic impairment evaluation as of December 31, 2025.

On February 4, 2026, the Company entered into an asset purchase agreement (the "Canada APA") to sell all of our operating assets in Canada (the "Canada Asset Divestment") to a third party purchaser for a purchase price of $24.4 million

(C$33.4 million) to be settled in cash, subject to customary adjustments. The Canada Asset Divestment closed on February 19, 2026 with an effective date of February 1, 2026 for an adjusted purchase price of $25.5 million (C$34.9 million), subject to additional customary post-closing adjustments. The net cash proceeds from the divestment was primarily used to fund our capital expenditures and for working capital purposes. The Canada Asset Divestment represents the Company's complete exit of its Canadian oil and gas operations.

Acquisition of Interest in CI-705 Block

In March 2025, the Company farmed into the CI-705 block offshore Côte d'Ivoire. The Company is the operator of the CI-705 block with a 70% working interest and a 100% paying interest through a commercial carry arrangement and is partnering with two other parties. The CI-705 block is located in the Tano basin, west of the Company's CI-40 Block, where the Baobab and Kossipo oil fields are located. The total amount of acquisition costs for this transaction is approximately $3.0 million.

FPSO Acquisition

In February 2025, the Company, through the joint operating agreement operator, completed the acquisition of the Baobab floating, production, storage and offloading vessel (the "Baobab FPSO") in Côte d'Ivoire for a total purchase price of $20.0 million, or approximately $6.1 million net cost to the Company.

Svenska Acquisition

On April 30, 2024, the Company completed the acquisition of all of the issued shares in the capital of Svenska Petroleum Exploration Aktiebolag, a company incorporated in Sweden ("Svenska") for a net adjusted purchase price of $40.2 million (the "Svenska Acquisition"). The total purchase price consideration was funded with $40.2 million of the Company's cash-on-hand. Cash acquired in the business combination included $31.8 million of cash and cash equivalents as well as restricted cash of $8.8 million which nets to $0.4 million cash received on the business combination within the purchase price allocation.

As a result of comparing the purchase price to the fair value of the assets acquired and liabilities assumed, an initial $19.9 million bargain purchase gain was recognized as of the close date. The purchase price allocation was finalized in the fourth quarter of 2024 and the Company made adjustments to the amounts assigned to the net assets acquired based on new information obtained about facts and circumstances that existed as of the Svenska Acquisition date. As a result, the bargain purchase gain was reduced by $6.4 million. The bargain purchase gain is primarily attributable to a stronger forward pricing curve for oil and gas reserves on the date of the closing of the acquisition than was used for the purposes of the negotiations of the purchase price paid for Svenska.

The Svenska Acquisition qualified as a business combination and was accounted for using the acquisition method of accounting. The following tables summarize the cash paid for the purchase price and the final purchase price allocation of the acquisition consideration.

	April 30, 2024	Measurement Period Adjustment	April 30, 2024 (As Adjusted)
		(in thousands)	
Purchase Consideration			
Cash	$ 40,166	$ —	$ 40,166
Total purchase consideration	$ 40,166	$ —	$ 40,166

	April 30, 2024	Measurement Period Adjustment	April 30, 2024 (As Adjusted)
		(in thousands)	
Assets acquired:			
Cash and cash equivalents	$ 31,789	$ 466	$ 32,255
Other receivables, net	830	—	830
Crude oil inventory	14,981	—	14,981
Prepayments and other	409	—	409
Crude oil, natural gas and NGLs properties and equipment, net	100,188	6,901	107,089
Restricted cash	8,788	—	8,788
Other LT receivables	33	—	33
Deferred tax asset	28,153	(12,095)	16,058
Total assets acquired	185,171	(4,728)	180,443
Liabilities assumed:			
Accounts payable	(2,506)	—	(2,506)
State oil liability	(19,447)	—	(19,447)
Accrued tax settlement	(8,788)	—	(8,788)
Accrued accounts payable invoices	(21,692)	—	(21,692)
Accrued liabilities and other	(19,083)	(301)	(19,384)
Asset retirement obligations	(15,694)	(11,617)	(27,311)
Deferred tax liability	(37,897)	10,280	(27,617)
Total liabilities acquired	(125,107)	(1,638)	(126,745)
Bargain purchase gain	(19,898)	6,366	(13,532)
Total purchase price	$ 40,166	$ —	$ 40,166

Post-Acquisition Operating Results. The table below summarizes amounts contributed by the Cote d'Ivoire assets acquired in the Svenska Acquisition to the Company's consolidated results for the period from April 30, 2024 through December 31, 2024.

	April 30, 2024 through December 31, 2024
	(in thousands)
Crude oil, natural gas and natural gas liquids sales	$ 95,082
Net income	12,143

The unaudited pro forma results presented below have been prepared to give effect to the Svenska Acquisition discussed above on the Company's results of operations for the year ended December 31, 2024 and 2023, as if the acquisition had been consummated on January 1, 2023. The unaudited pro forma results do not purport to represent what the Company's actual results of operations would have been if the Svenska Acquisition had been completed on such date or to project the Company's results of operations for any future date or period.

	Year Ended December 31,	
	2024	2023
	(in thousands)	
Pro forma (unaudited)		
Crude oil, natural gas and natural gas liquids sales	$ 510,513	$ 632,514
Operating income	$ 120,681	243,228
Net income[(a)(b)]	$ 38,336	95,740
Basic net income per share:		
Net income	$ 38,336	$ 95,740
Net income per share	$ 0.37	$ 0.90
Basic weighted average shares outstanding	103,669	106,376
Diluted net income per share:		
Net income	$ 38,336	$ 95,740
Net income per share	$ 0.37	$ 0.90
Diluted weighted average shares outstanding	103,747	106,555

(a) The unaudited pro forma net income (loss) for the year ended December 31, 2024 excludes a nonrecurring pro forma adjustment directly attributable to the Svenska Acquisition, consisting of a bargain purchase gain of $13.5 million.
(b) The unaudited pro forma net income (loss) for the year ended December 31, 2023 excludes a nonrecurring pro forma adjustment attributable to the TransGlobe Acquisition, consisting of a bargain purchase gain adjustment of $1.4 million.

5. EARNINGS PER SHARE

Basic earnings per share ("EPS") is calculated using the average number of shares of common stock outstanding during each period. For the calculation of diluted shares, the Company assumes that restricted stock is outstanding on the date of vesting, and the Company assumes the issuance of shares from the exercise of stock options using the treasury stock method.

A reconciliation of reported net income (loss) to net income (loss) used in calculating EPS as well as a reconciliation from basic to diluted shares follows:

	Year Ended December 31,		
	2025	**2024**	**2023**
		(in thousands)	
Net income (loss) (numerator):			
Net income (loss)	**$ (41,391)**	$ 58,490	$ 60,354
Income attributable to unvested shares	**(475)**	(714)	(632)
Numerator for basic	**(41,866)**	57,776	59,722
Income attributable to unvested shares	—	—	1
Numerator for dilutive	**$ (41,866)**	$ 57,776	$ 59,723
Weighted average shares (denominator):			
Basic weighted average shares outstanding	**104,055**	103,669	106,376
Effect of dilutive securities	—	78	179
Diluted weighted average shares outstanding	**104,055**	103,747	106,555
Stock options and unvested restricted stock grants excluded from dilutive calculation because they would be antidilutive	**3,608**	516	385

6. REVENUE

Production Sharing Contracts

Exploration and production activities of our assets in Gabon, Egypt, Cote d'Ivoire, and Equatorial Guinea are generally governed by PSCs.

Our oil entitlement under the PSCs is generally the sum of cost oil, profit oil and excess cost oil, if applicable. Under the terms of the PSCs, the Company is typically the contractor partner ("Contractor") and bears the risk and cost of exploration, development, and production activities. In return, if exploration is successful, the Contractor receives entitlement to variable physical volumes of hydrocarbons, representing recovery of the costs incurred ("Cost Oil") and a stipulated share of production after cost recovery ("Profit Oil").

The Contractor may be obligated to make royalty payments to the host government of each country using a variable percentage based on gross daily production levels. The remaining oil production, after deducting the gross royalty, if any, is split between Cost Oil and Profit Oil. Cost Oil is up to a maximum percentage and is allocated to recover approved operating and capital costs spent on specific projects. Excess Cost Oil, which is Cost Oil less the actual cost recovery, is further shared between the host government and the Contractor. Except as otherwise disclosed, all crude oil sales are priced at current market rates at the time of sale.

Our share of royalties is paid out of the government's share of production. Additionally, the income tax to which the Contractor is subject to ("Profit Oil Tax"), is deemed to have been paid to the host government as part of the payment of Profit Oil or is captured in the entitled share of Profit Oil production paid in-kind to the host government, and therefore no additional tax burden is due. Under this arrangement taxation is based on a set percentage of average daily production volume.

Gabon

Revenues from contracts with customers are generated from sales in Gabon pursuant to crude oil sales and purchase agreements ("COSPAs") or crude oil sales and marketing agreements ("COSMA or COSMAs"). Except for internal costs, which are expensed as incurred, there are no upfront costs associated with obtaining a new COSPA or COSMA.

Customer sales generally occur on a monthly basis when the customer's tanker arrives at the FPSO or FSO and the crude oil is delivered to the tanker through a connection. There is a single performance obligation (delivering crude oil to the delivery point, i.e. the connection to the customer's crude oil tanker) that gives rise to revenue recognition at the point in time when the performance obligation event takes place. This is referred to as a "lifting". Liftings can take one to two days to complete.

The Company accounts for sales based on the Company's working interest, less royalties. Imbalances are valued based on the actual sales proceeds. Historically as operator, the volumes sold may be more or less than the volumes that the Company is entitled based on the ownership interest in the property, and the Company would recognize a liability if the volumes sold exceeded the Company's ownership interest.

For each lifting completed under a COSPA or COSMA, payment is made by the customer in U.S. dollars by electronic transfer 30 days after the date of the bill of lading. For each lifting of crude oil, pricing is based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors.

The terms of the Etame PSC includes provisions for payments to the government of Gabon for: royalties based on 13% of production at the published price and a shared portion of Profit Oil determined based on daily production rates, as well as a gross carried working interest of 7.5% (increasing to 10% beginning June 20, 2026) for all costs. For both royalties and Profit Oil, the Etame PSC provides that the government of Gabon may settle these obligations in-kind, i.e. taking crude oil barrels, rather than with cash payments.

To date, the government of Gabon has not elected to take its royalties in-kind, and this obligation is settled through a monthly cash payment. Payments for royalties are reflected as a reduction in revenues from customers.

With respect to the government's share of Profit Oil, the Etame PSC provides that corporate income tax is satisfied through the payment of Profit Oil. In the consolidated statements of operations and comprehensive income (loss), the government's share of revenues from Profit Oil is reported in revenues with a corresponding amount reflected in the current provision for income tax expense. The amount associated with the Profit Oil under the terms of the Etame PSC is reflected as revenue with an offsetting amount reported in current income tax expense. Payments of the income tax expense are reported in the period that the government takes its Profit Oil in-kind, which is the period in which it lifts the crude oil. For the years ended December 31, 2025 and 2024, we made total in-kind payments through production liftings of $31.8 million and $30.3 million, respectively. As of December 31, 2025 and 2024, we had foreign income tax payables of $18.8 million and $40.0 million, respectively.

Certain amounts associated with the carried interest in the Etame Marin block are reported as revenues. In this carried interest arrangement, the carrying parties, which include the Company and other working interest owners, are obligated to fund all of the working interest costs that would otherwise be the obligation of the carried party. The carrying parties recoup these funds from the carried interest party's revenues.

The following table presents revenues in Gabon from contracts with customers as well as revenues associated with the obligations under the Etame PSC:

	Year Ended December 31,		
	2025	**2024**	**2023**
Revenues from customer contracts:		*(in thousands)*	
Sales under the COSPA or COSMA	**$ 176,508**	$ 205,965	$ 261,801
Gabonese government share of Profit Oil taken in-kind	**31,845**	30,256	32,776
Carried interest recoupment	**1,865**	2,276	5,301
Royalties	**(28,480)**	(32,543)	(39,532)
Net revenues	**$ 181,738**	$ 205,954	$ 260,346

Egypt

Revenues from sales in Egypt are generally made through direct sales to EGPC or through contracts with customers pursuant to crude oil sales and purchase agreements ("COSPAs") or crude oil sales and marketing agreements ("COSMA or COSMAs"). EGPC and the Company each own a 50% interest, respectively, in the operating company which is a party to the Merged Concession Agreement. EGPC and the Company each also own a 50% interest, respectively, in the operating company that is a party to the South Ghazalat concession agreement.

Customer sales generally occur when sales are directly to EGPC or haphazardly production is sold through a cargo lifting. The Company records EGPC's share of production as royalties which are netted against revenue, whether EGPC's share of production arises from EGPC's share of Profit Oil or excess Cost Oil.

With respect to Egyptian income taxes, these taxes are paid by EGPC on behalf of the Company out of EGPC's share of production entitlement. The income taxes paid to the Arab Republic of Egypt on behalf of the Company are recognized as crude oil revenue and income tax expense.

EGPC owns the storage and export facilities where the Company's production is delivered and the Company requires EGPC's cooperation and approval to schedule liftings. Once liftings occur, the Company has a 30-day collection cycle on liftings as a result of direct marketing to international purchasers. Depending on the Company's assessment of the credit of crude oil cargo buyers, they may be required to post irrevocable letters of credit to support the sales prior to the cargo liftings.

In some instances, the Company will borrow or loan production volumes in order to achieve a required amount of crude oil for cargo sales. In these instances, the Company can be in an overlift or underlift position. Regardless of being in an overlift or underlift position, sales are based on the Company's working interest, less royalties. Imbalances are valued based on the actual sales proceeds and the Company will record a payable, if in an overlift position, or a receivable, if in an underlift position, based on the fair value of the consideration received or receivable.

The following table presents revenues in Egypt from contracts with customers:

	Year Ended December 31,		
	2025	**2024**	**2023**
Revenues from customer contracts:		*(in thousands)*	
Gross sales	**$ 225,957**	$ 250,946	$ 272,613
Royalties	**(85,250)**	(104,449)	(110,569)
Selling costs	**(744)**	(531)	(995)
Net revenues	**$ 139,963**	$ 145,966	$ 161,049

Canada

Prior to the Canada Asset Divestment, customer sales generally occurred on a daily basis when crude oil, natural gas, condensate or NGL's were sold, normally via pipeline, to a delivery point. There is a single performance obligation (delivering crude oil, natural gas, condensate or NGL's to the delivery point) that gives rise to revenue recognition at the point in time when the performance obligation event takes place. The Company paid royalties to the Alberta provincial government and other mineral rights owners in accordance with the established royalty regime. The Company recorded revenues net of royalties.

Settlement of accounts receivable in Canada occurred on the 25th of the following month following production.

The following table presents revenues in Canada from contracts with customers:

	Year Ended December 31,		
	2025	**2024**	**2023**
Revenues from customer contracts:		*(in thousands)*	
Oil revenue	**$ 15,319**	$ 28,418	$ 28,287
Gas revenue	**2,052**	1,849	3,467
NGL revenue	**5,804**	7,646	8,440
Other revenue	**164**	213	—
Royalties	**(3,330)**	(5,009)	(5,821)
Selling costs	**(835)**	(1,131)	(702)
Net revenues	**$ 19,174**	$ 31,986	$ 33,671

Cote d'Ivoire

The Company owns a 27.39% non-operated working interest in the deepwater producing Baobab field in Block CI-40, offshore Cote d’Ivoire in West Africa. Production generated from the Baobab field is shared under a PSC (the “Cote d'Ivoire PSC”). In addition, in March 2025, the Company farmed into the CI-705 block offshore Côte d’Ivoire as the operator with a 70% working interest and a 100% paying interest.

Revenues from contracts with customers are generated from sales in Cote d'Ivoire pursuant to crude oil sales and purchase agreements (“COSPAs”), and revenues are recognized when a lifting, as defined below, is completed.

Customer sales generally occur on a monthly basis when the customer’s tanker arrives at the FPSO and the crude oil is delivered to the tanker through a connection. There is a single performance obligation (delivering crude oil to the delivery point, i.e. the connection to the customer’s crude oil tanker) that gives rise to revenue recognition at the point in time when the performance obligation event takes place. This is referred to as a “lifting”. Liftings can take one to two days to complete.

The Company accounts for sales based on the Company’s working interest, less royalties. Imbalances are valued based on the actual sales proceeds. The volumes sold may be more or less than the volumes that the Company is entitled based on the ownership interest in the property, and the Company would recognize a liability if the volumes sold exceeded the Company’s ownership interest.

For each lifting completed under the sales and purchase agreement, payment is made by the customer in U.S. dollars by electronic transfer 30 days after the date of the bill of lading. For each lifting of crude oil, pricing is based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors.

Cost Oil allows the Company to recover its capital and production costs and the costs carried by the Company on behalf of the government state oil company. Profit Oil is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the government of Cote d'Ivoire (the “Ivorian Government”). The Ivorian Governments’ share of Profit Oil attributable to the Company’s equity interest is reported in revenues with a corresponding amount reflected in the current provision for income tax expense. In addition, under the terms of the Cote d'Ivoire PSC, the tax payments to the Ivorian Government are deemed satisfied by its share of the Profit Oil.

The following table presents revenues in Cote d'Ivoire from contracts with customers:

	Year Ended December 31,	
	2025	**2024**
Revenues from customer contracts:	*(in thousands)*	
Sales under the sales and purchase agreements	**$ 16,528**	$ 87,870
Cote d’Ivoire government share of Profit Oil taken in-kind	**1,869**	7,212
Net revenues	**$ 18,397**	$ 95,082

Information about the Company's most significant customers -

For the years ended December 31, 2025, 2024 and 2023, our revenue concentration by customer for each operating segment are shown on the table below.

	Year Ended December 31,		
	2025	**2024 (1)**	**2023**
Gabon	100%	100%	100%
Egypt	100%	100%	62% and 38%
Cote d'Ivoire	100%	87% and 13%	—%
Canada	51%, 20% and 15%	41%, 32% and 21%	52%, 37% and 7%

(1) For Cote d'Ivoire, reflects sales from April 30, 2024 through December 31, 2024 related to the Svenska Acquisition.

7. INCOME TAXES

Income (loss) before income taxes is attributable as follows:

	Year Ended December 31,		
(in thousands)	2025	2024	2023
U.S.	**$ (24,853)**	$ (26,337)	$ (15,781)
Foreign	**(1,716)**	166,134	165,927
	$ (26,569)	$ 139,797	$ 150,146

Provision for income taxes related to income (loss) consists of the following:

	Year Ended December 31,		
	2025	2024	2023
U.S. Federal:		*(in thousands)*	
Current	$ —	$ —	$ —
Deferred	**(1,940)**	(1,698)	6,214
Foreign:			
Current	**44,341**	98,882	92,642
Deferred	**(27,579)**	(15,877)	(9,079)
Total	**$ 14,822**	$ 81,307	$ 89,777

The reconciliation of income tax expense (benefit) to income tax at the U.S. statutory rate is as follows:

(in thousands)	Year Ended December 31, 2025	
U.S. Federal Statutory Tax Rate	**$ (5,580)**	21.00 %
Domestic Federal		
Tax Credits - Foreign Tax Credit	**(13,982)**	52.63 %
Changes in Valuation Allowance	**7,385**	(27.79)%
Cross-border tax laws - US taxation of foreign disregarded entity	**8,242**	(31.02)%
Nontaxable or nondeductible items	**806**	(3.03)%
Foreign Tax Effects		
Gabon		
Statutory income tax rate differential	**4,923**	(18.53)%
Rate difference between Gabon statutory tax rate and the PSC	**9,435**	(35.51)%
Nontaxable or nondeductible items:		
Non Recoverable Costs	**1,067**	(4.02)%
Nondeductible Interest	**1,670**	(6.29)%
Impact of revenue differences between production and lifting	**(8,075)**	30.39 %
Carried interests	**(1,020)**	3.84 %
Other reconciling items	**478**	(1.80)%
Changes in Valuation Allowance	**2,095**	(7.89)%
Egypt		
Statutory income tax rate differential	**9,067**	(34.13)%
Nontaxable or nondeductible items:		
Non Recoverable Costs	**2,288**	(8.61)%
Other reconciling items	**(92)**	0.35 %
Changes in Valuation Allowance	**356**	(1.34)%

Canada		
Statutory income tax rate differential	**4,184**	(15.75)%
Subnational income taxes	**(5,580)**	21.00 %
Changes in Valuation Allowance	**16,045**	(60.39)%
Cote D'Ivoire		
Statutory income tax rate differential	**(716)**	2.70 %
Rate difference between statutory tax rate and the PSC	**(12,197)**	45.91 %
Nontaxable or nondeductible items:		
Non Recoverable Costs	**1,033**	(3.89)%
Stat to US GAAP adjustments	**(1,250)**	4.71 %
Cost Recovery Uplift	**(9,167)**	34.50 %
Changes in Valuation Allowance	**1,834**	(6.90)%
Equatorial Guinea		
Statutory income tax rate differential	**(119)**	0.45 %
Changes in Valuation Allowance	**744**	(2.80)%
Sweden		
Tax Credits - Foreign Tax Credit	**(3,767)**	14.18 %
Cross-border tax laws - Sweden taxation of foreign disregarded entity	**(2,885)**	10.86 %
Nontaxable or nondeductible items:		
Realized foreign exchange gain	**4,036**	(15.19)%
Other reconciling items	**(100)**	0.38 %
Changes in Valuation Allowance	**3,126**	(11.76)%
Other		
Nontaxable or nondeductible items:		
Other reconciling items	**538**	(2.03)%
Total	**$ 14,822**	(55.77)%

Income taxes paid (net of refunds received) were as follows:

	December 31,	
(in thousands)	**2025**	**2024**
Gabon	**$ 36,739**	$ 31,109
Egypt	**29,025**	31,355
Cote d’Ivoire	**2,221**	9,155
Total taxes paid	**$ 67,985**	$ 71,619

Deferred tax assets and liabilities, which are computed on the estimated income tax effect of temporary differences between financial and tax bases in assets and liabilities, are determined using the tax rates expected to be in effect when taxes are actually paid or recovered.

In assessing the realizability of the deferred tax assets, the Company considers all available positive and negative evidence by jurisdiction to estimate whether it is more likely than not that sufficient future taxable income will be generated to permit the use of the existing deferred tax assets. The ultimate realization of the deferred tax assets is dependent upon the generation of future income in periods in which the deferred tax assets can be utilized. Numerous judgments and assumptions are inherent in this assessment, including the determination of future taxable income, future operating conditions, particularly as related to prevailing crude oil prices.

On the basis of this evaluation, as of December 31, 2025, a valuation allowance of $203.6 million has been recorded to recognize only the portion of the deferred tax asset that is more likely than not to be realized. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income are reduced or increased.

The tax effects of significant temporary differences giving rise to deferred tax assets and liabilities are as follows:

	December 31,	
(in thousands)	**2025**	**2024**
Deferred tax assets:		
Fixed assets[1]	**$ 40,988**	$ 35,541
Foreign tax credit carryforward	**133,803**	123,660
Net operating losses	**58,892**	56,317
Asset retirement obligations	**48,015**	20,384
ROU lease liabilities	**8,567**	9,973
Accrued liabilities	**16,071**	19,686
Receivables	**(146)**	(1,788)
Other	**3,846**	2,682
Total deferred tax assets	**310,036**	266,455
Valuation allowance	**(203,624)**	(173,140)
Net deferred tax assets	**$ 106,412**	$ 93,315
Deferred tax liabilities:		
Basis difference in fixed assets	**(115,217)**	(131,639)
Net deferred tax liabilities	**$ (115,217)**	$ (131,639)

(1) This line includes ROU lease asset.

The Corporation's undistributed earnings from subsidiary companies outside the United States include amounts that have been retained to fund prior and future capital project expenditures. Deferred income taxes have not been recorded for potential future tax obligations, such as foreign withholding tax and state tax, as these undistributed earnings are expected to be indefinitely reinvested for the foreseeable future. As of December 31, 2025, it is not practicable to estimate the unrecognized deferred tax liability. However, unrecognized deferred taxes on remittance of these funds are not expected to be material.

The Company has NOL's, in the following jurisdictions as of December 31, 2025:

Jurisdiction	**Amount** *(in thousands)*	**Expiration Period**
Egypt	$ 14,596	2026-2028
Canada	$ 91,662	2031-2040
Equatorial Guinea	$ 127,564	No expiration

The Company recognizes the financial statement benefit of a tax position only after determining that they are more likely than not to sustain the position following an audit. The Company believes that its income tax positions and deductions will be sustained on audit, and therefore no reserves for uncertain tax positions have been established. Accordingly, no interest or penalties have been accrued as of December 31, 2025 and 2024. The Company's policy is to include interest and penalties related to unrecognized tax benefits as a component of income tax expense.

The Company is subject to income taxation in the United States and various foreign jurisdictions, including Canada. The Company's Canadian subsidiaries are currently under examination by the Canada Revenue Agency ("CRA") with respect to the tax treatment of the disposition of shares of certain foreign affiliates for taxation years included in the year ended December 31, 2022.

In January 2026, the Company received an assessment from the CRA related to this examination. The Company is currently evaluating the assessment and available administrative remedies, including the filing of a notice of objection. The Company is also considering this matter in connection with the previously announced sale of the Company's Canadian assets. As of December 31, 2025, there have been no developments or new information that would require the Company to record an unrecognized tax benefit. Based on currently available information, the Company does not believe that the ultimate resolution of this matter will have a material adverse effect on its consolidated financial position, tax expense, results of operations, or cash flows; however, the final outcome remains uncertain.

For the years ended December 31, 2025, 2024 and 2023, the Company is subject to foreign and U.S. federal taxes only, with no allocations made to state and local taxes. The following table summarizes the tax years that remain subject to examination by major tax jurisdictions.

Jurisdiction	Years
U.S.	2015-2025
Gabon	2021-2025
Egypt	2020-2025
Canada	2020-2025
Sweden	2019-2025
Cote d'Ivoire	2022-2025

8. CRUDE OIL, NATURAL GAS AND NGLs PROPERTIES AND EQUIPMENT, NET

The Company's crude oil, natural gas and NGLs properties and equipment, net, at December 31, 2025 and 2024 is comprised of the following:

	2025	2024
	(in thousands)	
Crude oil, natural gas and NGLs properties and equipment, net		
Wells, platforms and other production facilities	**$ 1,016,019**	$ 1,593,243
Work-in-progress	**214,213**	44,517
Unproved properties	**52,079**	60,761
Capitalized equipment, spare parts and other	**84,471**	75,581
	1,366,782	1,774,102
Accumulated depreciation, depletion, amortization and impairment	**(780,687)**	(1,235,999)
Crude oil, natural gas and NGLs properties and equipment, net	**$ 586,095**	$ 538,103

Unproved property costs

See the table below for the list of unproved property costs at December 31, 2025 and 2024:

	2025	2024
	(in thousands)	
Unproved Property Costs		
Gabon	**15,235**	$ 13,735
Equatorial Guinea	**10,000**	10,000
Egypt	**11,035**	11,542
Cote d'Ivoire	**15,809**	12,775
Canada	**—**	12,709
Unproved Property Costs	**$ 52,079**	$ 60,761

At December 31, 2025, the Company classified $31.8 million of net Crude oil, natural gas and NGLs properties and equipment, including unproved property costs of $13.1 million, as "Noncurrent asset held for sale" on the Consolidated Balance Sheet.

Exploration expense

During the year ended December 31, 2025, we incurred exploration expenses of $8.9 million, which included exploratory costs related to a well determined to be not commercially viable in South Ghazalat, the cost of additional seismic data to be used in Block 705 in Cote d'Ivoire, and expenses related to Blocks G and H in Gabon. We had minimal exploration expenses during 2024.

9. DERIVATIVES

We have entered into derivative contracts primarily with counterparties that are also lenders under the 2025 RBL Facility (defined below) to hedge price risk associated with a portion of our oil, natural gas and NGLs production. In addition, pursuant to the terms of the 2025 RBL Facility agreement, if the aggregate borrowings under the 2025 RBL Facility exceeds 35% of the lower of (a) the available total commitments and (b) the applicable borrowing base amount, we are required to enter into commodity price hedge positions covering certain volumes of anticipated future production set out in the banking case. Pricing for these derivative contracts is based on certain market indexes and prices at our primary sales points. See table below for the list of outstanding contracts as of December 31, 2025:

		Settlement Period			
Instrument	**Index**	**January 2026 - March 2026**	**April 2026 - June 2026**	**July 2026 - September 2026**	**October 2026 - December 2026**
Crude oil:					
Collars	Dated Brent				
Total volumes (Bbls)		400,000	360,000	75,000	—
Weighted average floor price ($/Bbl)		$ 62.29	$ 61.88	$ 65.00	$ —
Weighted average ceiling price ($/Bbl)		$ 68.63	$ 67.95	$ 71.00	$ —
Natural Gas[(a)]:					
Swaps	AECO 7A				
Total volumes (GJs)[(b)]		225,000	150,000	150,000	50,000
Weighted average fixed price (CAD/GJ)		$ 2.99	$ 2.80	$ 2.80	$ 2.80

(a) Natural gas hedge contracts were assumed by the third-party purchaser upon closing of the sale pursuant to the Canada APA.
(b) One gigajoule (GJ) equals one billion joules (J). A gigajoule of natural gas is approximately 25.5 cubic meters standard conditions.

See Note 2. Summary of Significant Accounting Policies for further details on the measurement of our derivative assets at fair value.

The following table sets forth the gain (loss) on derivative instruments on the Company's consolidated statements of operations and comprehensive income (loss):

		Year Ended December 31,		
Derivative Item	**Statements of Operations Line**	**2025**	**2024**	**2023**
			(in thousands)	
Commodity derivatives	Cash settlements paid on matured derivative contracts, net	**$ (48)**	$ (453)	$ (127)
	Unrealized gain (loss)	**2,924**	(292)	359
	Derivative instruments gain (loss), net	**$ 2,876**	$ (745)	$ 232

10. ASSET RETIREMENT OBLIGATIONS

The following table summarizes the changes in the Company's asset retirement obligations:

	Year Ended December 31,	
(in thousands)	**2025**	**2024**
Beginning balance	**$ 79,766**	$ 47,343
Accretion	**6,364**	4,753
Additions	**2**	27,424
Revisions	**427**	981
Settlements	**(225)**	(368)
Liabilities classified as held for sale	**(7,586)**	—
Foreign currency loss	**(342)**	(367)
Ending balance	**78,406**	79,766
Less: current obligations	**—**	(1,174)
Long-term asset retirement obligation	**$ 78,406**	$ 78,592

Accretion is recorded in the line item "Depreciation, depletion and amortization" on the consolidated statements of operations and comprehensive income (loss).

11. COMMITMENTS AND CONTINGENCIES

Abandonment funding

Gabon

Under the terms of the Etame PSC, the Company has a cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin block. As a result of the PSC Extension, annual funding payments are spread over the life of the Etame Marin Block, under the applicable abandonment study. The amounts paid will be reimbursed through the Cost Account and are non-refundable. In August 2023, an abandonment study was completed which estimated abandonment costs of approximately $77.9 million ($45.9 million, net to VAALCO) on an undiscounted basis. The abandonment estimate was presented to the Gabonese Directorate of Hydrocarbons as required by the PSC. At December 31, 2025, $10.7 million ($6.3 million, net to VAALCO) on an undiscounted basis has been funded. The annual payments will be adjusted based on revisions in the abandonment estimate. This cash funding is reflected under "Other noncurrent assets" in the "Abandonment funding" line item of the consolidated balance sheets. Future changes to the anticipated abandonment cost estimate could change the asset retirement obligation and the amount of future abandonment funding payments.

In the first quarter of 2023, the Directorate of Hydrocarbons in Gabon approved a $26.6 million ($15.6 million, net to VAALCO) abandonment funding payment associated with the FPSO retirement. The Company received payment of $15.6 million in March 2023. No other activity occurred in the abandonment funding account through the end of 2025. The Company is working with the Directorate of Hydrocarbons in Gabon to establish a payment schedule to resume funding of the abandonment fund in compliance with the Etame PSC.

Share Buyback Program

On November 1, 2022, the Company announced that the Company's Board of Directors formally ratified and approved a share buyback program. The Board of Directors also directed management to implement a Rule 10b5-1 trading plan (the "10b5-1 Plan") to facilitate share purchases through open market purchases, privately negotiated transactions, or otherwise in compliance with Rule 10b-18 under the Securities Exchange Act of 1934. The 10b5-1 Plan provided for an aggregate purchase of currently outstanding common stock up to $30 million over a maximum period of 20 months. Payment for shares repurchased under the share buyback program were funded using the Company's cash on hand and cash flow from operations. The share buyback program was completed on March 12, 2024. Under the share buyback program, we purchased a total of 6,797,711 shares at an average price of $4.41 per share.

Regulatory and Joint Interest Audits and Related Matters

The Company is subject to periodic audits by various government agencies from the international jurisdictions where we operate, including audits by the respective governments and other members of the Company's joint operating agreements.

Merged Concession Agreement

The Company is a party to the Merged Concession Agreement with the Egyptian General Petroleum Corporation ("EGPC"). In accordance with the Merged Concession Agreement, we were required to make $10.0 million annual modernization payments through February 1, 2026. As of December 31, 2025, all modernization payments had been fully settled either through actual cash payments or through the issuance of credit against receivables owed from EGPC.

The Company also has minimum financial work commitments of $50.0 million per each five-year period of the primary development term, commencing on February 1, 2020 for a total of $150 million over the 15 year license contract term. Through December 31, 2025, the Company's financial work commitments have exceeded the five-year minimum $50 million threshold and any excess carries forward to offset against subsequent five-year commitments.

The amounts that will be paid for such outstanding off-balance sheet financial work commitments as of December 31, 2025 are $10.0 million in 2026, $10.0 million in 2027, $10.0 million in 2028, $10.0 million in 2029, $10.0 million in 2030 and $50.0 million in 2031 and thereafter.

Domestic Market Obligation

Under the terms of the respective PSCs in Gabon and Cote d'Ivoire, the Company can be required to sell to the Government or another entity designated by the Government, a certain percentage of its Profit Oil to meet the needs of the domestic market.

Drilling Rig Commitment

The Company entered into a bareboat charter agreement (the "Bareboat Charter") during the fourth quarter of 2024 to charter a drilling rig for its drilling program in Gabon. Pursuant to the Bareboat Charter, the Company also entered into a service agreement with a third party for purposes of maintaining and operating the drilling rig on its behalf. The Bareboat Charter commenced on November 2025 upon the mobilization of the drilling rig towards the Company's first well and has a noncancellable period of 300 days plus five single well options. The Bareboat Charter stipulates fixed day rates and other variable payments.

12. DEBT

In April 2025, the Company drew down $60.0 million under the 2025 RBL Facility. The borrowing accrues interest at a rate of 10.8% per annum which is based on the Term SOFR plus the Applicable Margin of 6.5% per annum. In addition, the borrowing is due to be repaid within three months from the drawdown date with, subject to certain conditions, the option to rollover the debt upon maturity.

As of December 31, 2025, there were $60.0 million of outstanding borrowings under the 2025 RBL Facility. There were no outstanding borrowings as of December 31, 2024.

In addition, as of December 31, 2025 and 2024, we were in compliance with all of our debt covenants.

2025 RBL Facility

On March 4, 2025, the Company and certain of its subsidiaries (the "Vaalco Energy Group"), entered into a reserves-based facility agreement (the "2025 Facility Agreement") providing for a senior secured reserve-based revolving credit facility (the "2025 RBL Facility") with The Standard Bank of South Africa Limited (acting through its Corporate and Investment Banking Division) as agent and security agent, The Standard Bank of South Africa Limited, Isle of Man Branch and the other financial institutions named in the 2025 Facility Agreement (the "Lenders"), providing for the 2025 RBL Facility.

The 2025 RBL Facility had initial aggregate commitments of $190.0 million (the “Initial Total Commitments”) as of March 4, 2025, with an initial borrowing base of $182.0 million, which was further increased to $184.0 million in April 2025 in accordance with the conditions that were met subsequent to entering into the 2025 Facility Agreement. The Initial Total Commitments originally would reduce semi-annually by $19.0 million starting from September 30, 2026. The borrowing base amount is calculated pursuant to the 2025 RBL Facility Agreement and redetermined on March 31 and September 30 of each year beginning June 30, 2025 and in certain circumstances, other interim triggers set out in the 2025 Facility Agreement. In 2025, we completed our June 30 and September 30 borrowing base redeterminations, which increased the borrowing base to $190.0 million.

The Company may, at any time prior to the date falling 30 months from the date of the 2025 Facility Agreement and subject to the conditions and process set out in the 2025 RBL Facility Agreement, give notice to the agent to increase the Initial Total Commitment up to a maximum amount of $300.0 million. Effective October 17, 2025, the Lenders approved to (i) extend the first date on which the Initial Total Commitments will be reduced from September 30, 2026 to March 31, 2027, and (ii) update the semi-annual commitment reduction amounts from $19.0 million to $10.0 million on March 31, 2027, and $22.5 million starting on September 30, 2027.

As of December 31, 2025, we had $190.0 million of aggregate facility commitments and $130.0 million of available borrowing capacity under the 2025 RBL Facility.

In addition, subject to certain conditions precedent, certain existing Lenders under the 2025 RBL Facility agreed to increase their initial commitment effective January 23, 2026 from $190.0 million to $255.0 million. The increase in commitments was undertaken with the existing accordion feature included in the 2025 RBL Facility.

On February 4, 2026, the Company borrowed an additional $65.0 million under the 2025 RBL Facility. The borrowing accrues interest at a rate of 10.2% per annum which is based on the Term SOFR plus the Applicable Margin of 6.5% per annum. In addition, the borrowing is due to be repaid within one month from the drawdown date with, subject to certain conditions, the option to rollover the debt upon maturity.

Each loan under the 2025 RBL Facility will bear interest at a rate equal to Term Secured Overnight Financing Rate (“SOFR”) plus the Applicable Margin of (i) 6.50%, from the date of the 2025 Facility Agreement until the date on which the renovation and repair of the floating production storage and offloading tanker facility named Baobab Ivorian MV10 FPSO for use in connection with the development of the Baobab field (the “Baobab FPSO Renovation”) meets certain completion tests defined in the 2025 RBL Facility Agreement and (ii) thereafter, 6.00% until the Final Maturity Date (defined below). We shall pay the accrued interest on the last day of each applicable interest period, which interest period may be, at our option, one, three or six months or such other period as agreed to between us and the Lenders.

The 2025 RBL Facility will mature on the earlier of (i) March 4, 2031, which is the sixth anniversary of the date of the 2025 Facility Agreement and (ii) the Reserve Tail Date (the “Final Maturity Date”). The Reserve Tail Date is the last day of the calculation period immediately preceding the first calculation period in which the aggregate remaining reserves for all of the borrowing base assets are projected in the then current banking case to be less than 25% of the initial approved reserves.

The 2025 RBL Facility is secured against certain assets of the Company and the other obligors under the 2025 Facility Agreement. The security package includes security over the shares in the obligors (other than in the Company), hedging agreements, intercompany loans, insurances, offtake agreements relating to the borrowing base assets and project accounts.

The 2025 RBL Facility Agreement contains certain financial covenants, including that, beginning on June 30, 2025 and then as of each March 31 and September 30 until the Final Maturity Date, the ratio of Total Net Indebtedness to EBITDAX (each defined in the 2025 Facility Agreement) for the trailing 12 months shall not exceed 3.0x. Additionally, following the Baobab FPSO renovation completion date, the debt service coverage ratio for the trailing 12 months commencing on the day immediately following each March 31 and September 30 (and any interim redetermination date) until the Final Maturity Date shall be at least 1.2:1. The Company also provides a liquidity forecast for the Vaalco Energy Group which shall demonstrate that the total corporate sources equal or exceed the total corporate uses. The liquidity forecast is delivered quarterly during the Baobab FPSO renovation period and otherwise on each redetermination of the banking case and any proposed distribution.

The Company is required to pay a quarterly commitment fee equal to (i) 35% per annum of the Applicable Margin on the daily amount of the difference (if any) by which the borrowing base amount exceeds the then-outstanding amount of loans, plus (ii) 20% per annum of the Applicable Margin on the daily amount by which the then-total commitments exceeds the higher of the total outstanding amount of loans and the borrowing base amount. The Company is also required to pay customary technical and modelling bank fees, agency fees and security agent fees. The 2025 Facility Agreement also contains customary information covenants as well as affirmative and negative covenants subject to customary threshold and materiality which include, among others, compliance with laws (including environmental laws, sanctions and anti-corruption laws), delivery of quarterly and annual financial statements and compliance certificates, no change of business, no merger and maintenance of corporate existence, field preservations and related contracts relating to the borrowing base assets, maintenance of insurance, entry into certain derivatives contracts which are regulated by the 2025 Facility Agreement and the hedging policy, restrictions on the incurrence of liens, indebtedness, asset dispositions, acquisitions, restricted payments, entry into offtake agreements and other customary covenants. If the aggregate borrowings exceeds 35% of the lower of (a) the available total commitments and (b) the applicable borrowing base amount, we are also required to enter into commodity price hedge positions covering certain volumes of anticipated future production set out in the banking case. There are other covenants that make the Company's ability to pay dividends and to enter into certain acquisitions and disposition transactions subject to certain conditions. These covenants are subject to a number of limitations and exceptions.

Additionally, the 2025 RBL Facility Agreement contains customary events of default, including non-payment and borrowing base deficiency, funding shortfall subject to certain liquidity cure rights, breach of financial covenants, misrepresentation, insolvency, changes in ownership or business, litigation, cross default, expropriation of any borrowing base assets, political events, cessation of production and the occurrence of a material adverse effect. The 2025 Facility Agreement also contains events of default related to the failure to complete the Baobab FPSO Renovation by the Baobab FPSO Renovation long stop date determined in the 2025 Facility Agreement and the failure to renew any field license on substantially the same terms three months before the expiration of such field license and if a change of operator occurs. The events of default contains thresholds and remedy periods customary for credit facilities of this nature. If the obligors do not comply with the financial and other covenants relating to non-payment, sanctions, anti-corruption, loans and guarantee or tax in the 2025 Facility Agreement, the Lenders may require immediate payment of all amounts outstanding under the 2025 Facility Agreement and any outstanding unfunded commitments may be terminated. In addition, if any principal amount payable is not paid upon due date, interest shall accrue on the overdue amount from the due date up to the date of the actual payment at an additional interest rate of 2% per annum, and such interest shall be immediately payable on demand.

Fair Value Measurement

The fair value of the 2025 RBL Facility approximates its respective carrying amount as its interest rate is variable and reflective of current market rates. The fair value measurement for the 2025 RBL Facility represents Level 2 inputs.

13. LEASES

Under the leasing standard that became effective January 1, 2019*,* there are two types of leases: finance and operating. Regardless of the type of lease, the initial measurement of the lease results in recording a ROU asset and a lease liability at the present value of the future lease payments.

Operating leases

The Company is currently a party to three operating lease agreements for the corporate and Egypt offices and transportation equipment. The remaining lease term for these agreements ranges from 35 to 60 months. In some cases, the lease contracts require the Company to make payments both for the use of the asset itself and for operations and maintenance services. Only the payments for the use of the asset related to the lease component are included in the calculation of ROU assets and lease liabilities. Payments for the operations and maintenance services are considered non-lease components and are not included in calculating the ROU assets and lease liabilities. For leases on ROU assets used in joint operations, generally the operator reflects the full amount of the lease component, including the amount that will be funded by the non-operators. As operator for the Etame Marin block, the ROU asset recorded for certain equipment used in the joint operations includes the gross amount of the lease components.

The transportation equipment leases include provisions for variable lease payments, under which the Company is required to make additional payments based on the number of days or hours the asset is deployed. Because the Company does not know the extent that the Company will be required to make such payments, they are excluded from the calculation of ROU assets and lease liabilities.

Financing leases

The Company is currently a party to several financing lease agreements for the FSO and generators and marine vessels used in the operations of the Etame Marin block. The remaining lease term for these agreements ranges from 1 to 81 months months. In some cases, the lease contracts require the Company to make payments both for the use of the asset itself and for operations and maintenance services. Only the payments for the use of the asset related to the lease component are included in the calculation of ROU assets and lease liabilities. Payments for the operations and maintenance services are considered non-lease components and are not included in calculating the ROU assets and lease liabilities.

All leases

For all leases that contain an option to extend the initial lease term, the Company has evaluated whether it is reasonably certain that the Company will extend the lease beyond the initial lease term. When the Company believes it is reasonably certain it will utilize these leased assets beyond the initial lease term, those payments have been included in the calculation of the ROU assets and liabilities. The discount rate used to calculate ROU assets and lease liabilities represents the Company's incremental borrowing rate. The Company determined this by considering the term and economic environment of each lease, and estimating the resulting interest rate the Company would incur to borrow the lease payments.

For the years ended December 31, 2025, 2024 and 2023, the components of the lease costs and supplemental information was as follows:

	Year Ended December 31,		
	2025	**2024**	**2023**
Lease cost:		*(in thousands)*	
Finance lease cost [1]:			
Amortization of lease assets	**$ 13,558**	$ 12,924	$ 10,253
Interest on lease liabilities	**5,449**	6,274	7,044
Operating lease cost	**5,018**	5,100	1,403
Short-term lease cost [2]	**845**	893	6,574
Variable lease cost [3]	**1,964**	1	653
Total lease expense	**26,834**	25,192	25,927
Lease costs capitalized	**761**	—	55
Total lease costs	**$ 27,595**	$ 25,192	$ 25,982

(1) Represents depreciation and interest associated with financing leases.
(2) Represents short term leases under contracts that are 1 year or less where a ROU asset and lease liability are not required to be recorded.
(3) Variable costs represent differences between minimum lease costs and actual lease costs incurred under lease contracts.

Other information:

	Year Ended December 31,		
	2025	**2024**	**2023**
Other information:			
Cash paid for amounts included in the measurement of lease liabilities:			
Financing cash flows attributable to finance leases (in thousands)	**$ 13,289**	$ 10,477	$ 7,161
Weighted-average remaining lease term (in years)	**6.47**	7.36	8.16
Weighted-average discount rate	**7.21%**	7.16%	7.99%
Operating cash flows attributable to operating leases (in thousands)	**$ 6,531**	$ 2,127	$ 505
Weighted-average remaining lease term (in years)	**3.29**	4.09	0.67
Weighted-average discount rate	**6.53%**	6.14%	8.45%

The table below describes the presentation of the total lease cost on the Company's consolidated statements of operations and other comprehensive income (loss). As discussed above, the Company's joint venture owners are required to reimburse the Company for their share of certain expenses, including certain lease costs.

	Year Ended December 31,		
	2025	2024	2023
		(in thousands)	
Finance lease cost	**$ 11,179**	$ 11,290	$ 10,231
Production expense	**4,309**	3,517	3,556
General and administrative expense	**500**	346	196
Lease costs billed to the joint venture owners	**10,846**	10,039	11,964
Total lease expense	**26,834**	25,192	25,947
Lease costs capitalized	**761**	—	35
Total lease costs	**$ 27,595**	$ 25,192	$ 25,982

The following table describes the future maturities of the Company's operating and financing lease liabilities at December 31, 2025:

	Operating Leases	Finance Leases
Year	(in thousands)	
2026	**$ 6,646**	**$ 16,676**
2027	**5,431**	**15,216**
2028	**5,202**	**11,660**
2029	**958**	**11,660**
2030	**626**	**12,568**
Thereafter	**—**	**17,884**
	18,863	**85,664**
Less: imputed interest	**(1,936)**	**(16,289)**
Total lease liabilities	**$ 16,927**	**$ 69,375**

Under the joint operating agreements, other joint venture owners are obligated to fund approximately $41.3 million of the $104.5 million in future lease liabilities as of December 31, 2025.

14. ACCRUED LIABILITIES AND OTHER

Accrued liabilities and other balances were comprised of the following:

	As of December 31, 2025	
	2025	2024
	(in thousands)	
Accrued accounts payable invoices	**$ 16,320**	$ 48,913
State oil liability	**18,244**	19,616
Accrued capital expenditures	**51,339**	8,923
Egypt modernization payable	**—**	9,933
Gabon contractual obligations	**3,858**	6,977
Accrued wages and other compensation	**6,694**	4,956
Seismic data	**1,155**	2,455
Asset retirement obligation, current portion	**—**	1,174
Other	**8,834**	4,763
Total accrued liabilities and other[(a)]	**$ 106,444**	$ 107,710

(a) The table excludes $0.2 million of current portion of asset retirement obligations associated with assets held for sale.

15. SHAREHOLDERS' EQUITY

Dividend Policy

The following table is a schedule of dividends paid during 2025:

Dividend Payment Date	Amount per common share	Record Date
March 28, 2025	$ 0.0625	February 28, 2025
June 27, 2025	$ 0.0625	May 23, 2025
September 19, 2025	$ 0.0625	August 22, 2025
December 24, 2025	$ 0.0625	November 21, 2025
Aggregate per share amount paid in 2025	$ 0.2500	

Preferred stock – Authorized preferred stock consists of 500,000 shares with a par value of $25 per share. No shares of preferred stock were issued and outstanding as of December 31, 2025 or 2024.

Treasury stock

Please see discussion on the Company's share buyback program under Note 11. Commitments and Contingencies.

16. STOCK-BASED COMPENSATION AND OTHER BENEFIT PLANS

The Company's stock-based compensation has been granted under several stock incentive and long-term incentive plans. The plans authorize the Compensation Committee of the Company's Board of Directors to issue various types of incentive compensation. The Company had previously issued stock options and restricted shares under the 2014 Long-Term Incentive Plan and stock appreciation rights under the 2016 Stock Appreciation Rights Plan. On June 25, 2020, the Company's stockholders approved the 2020 Long-Term Incentive Plan (as amended, the "2020 Plan") under which 5,500,000 shares are authorized for grants. In June 2021, the Company's stockholders approved an amendment to the 2020 Plan pursuant to which an additional 3,750,000 shares were authorized for issuance pursuant to awards under the 2020 Plan. At December 31, 2025, 483,624 shares were available for future grants.

For each stock option granted, the number of authorized shares under the 2020 Plan will be reduced on a one-for-one basis. For each restricted share granted, the number of shares authorized under the 2020 Plan will be reduced by twice the number of restricted shares. The Company has no set policy for sourcing shares for option grants. Historically the shares issued under option grants have been new shares.

As referenced in the table below, the Company records compensation expense related to stock-based compensation as general and administrative expense associated with the issuance of stock options, restricted stock and stock appreciation rights. During the years ended December 31, 2024 and 2023, the Company settled in cash $0.2 million and $0.4 million, respectively, for SARs no amounts settled for 2025. During the years ended December 31, 2024 and 2023, the Company received in cash $0.4 million and $0.7 million, respectively from stock option exercises, no amounts received in 2025.

	Year Ended December 31,		
	2025	**2024**	**2023**
		(in thousands)	
Stock-based compensation - equity awards	**$ 5,954**	$ 4,567	$ 3,338
Stock-based compensation - liability awards	—	(9)	(15)
Total stock-based compensation	**$ 5,954**	$ 4,558	$ 3,323

Performance restricted stock units

The Company grants shares of its common stock to its executives in the form of shares of performance restricted stock unit ("PSS") awards. These awards are measured at the fair value of the underlying shares on the date of grant and recognized ratably as compensation expense over a period of three years, vesting in three equal parts on the anniversaries from the date of grant to the extent that the performance hurdles and service condition are met.

In June 2025, the Company granted 789,976 shares performance-based restricted stock awards ("PSS") to certain executives of the Company. The awards had a grant date fair value of approximately $1.8 million using a Monte Carlo Valuation model. The Company will recognize the entire $1.8 million of compensation expense for this award, regardless of whether such conditions are met, over the requisite service period unless units are forfeited during the period.

For each PSS stock award, one-third of the underlying shares vest on the later of the first anniversary of the grant date and the date on which the Company's stock price, determined using a 30-day average, exceeds $3.86 per share; PSS awards with respect to one-third of the underlying shares vest on the later of the second anniversary of the grant date and the date on which the Company's stock price, determined using a 30-day average, exceeds $4.45 per share; and PSS awards with respect to the remaining one-third of the underlying shares vest on the later of the third anniversary of the grant date and the date on which the Company's stock price, determined using a 30-day average, exceeds $5.12 per share. These PSS awards contain a requisite service period of 10 years.

During the year ended December 31, 2025, the weighted average assumptions shown below were used to calculate the weighted average grant date fair value of the PSS awards under the Monte Carlo model.

	Year Ended December 31, 2025
Average expected volatility	68.71%
Risk-free interest rate	4.40%
Expected dividend yield	7.44%
Weighted average grant date fair value - ($/share)	$ 2.29

PSS awards activity associated with the Monte Carlo model for the year ended December 31, 2025 is provided below:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term
	(in thousands)		*(in years)*
Unvested at January 1, 2025	—	$ —	
Granted	790	2.29	
Unvested at December 31, 2025	790	$ 2.29	1.75

The intrinsic value of a performance stock option awards is the amount that the current market value of the underlying stock exceeds the exercise price of the award.

As of December 31, 2025, unrecognized compensation cost related to unvested vesting awards was $1.3 million, which is expected to be recognized over a weighted average period of 1.75 years.

Stock options and performance shares

Stock options have an exercise price that may not be less than the fair market value of the underlying shares on the date of grant. In general, stock options granted to participants will become exercisable over a period determined by the Compensation Committee of the Company's Board of Directors that is generally a three-year period, vesting in three equal parts on the anniversaries from the date of grant, and may contain performance hurdles.

In June 2024, the Company granted options to certain employees of the Company that are considered performance stock options to purchase an aggregate of 549,495 shares at an exercise price of $5.96 per share and a life of ten years. For each performance stock option award, one-third of the underlying shares vest on the later of the first anniversary of the grant date and the date on which the Company's stock price, determined using a 30-day average, exceeds $6.85 per share; performance stock options with respect to one-third of the underlying shares vest on the later of the second anniversary of the grant date and the date on which the Company's stock price, determined using a 30-day average, exceeds $7.88 per share; and performance stock options with respect to the remaining one-third of the underlying shares vest on the later of the third anniversary of the grant date and the date on which the Company's stock price, determined using a 30-day average, exceeds $9.09 per share. These awards are option awards that contain a market condition. Compensation cost for such awards is recognized ratably over the derived service period and compensation cost related to awards with a market condition will not be reversed if the Company does not believe it is probable that such performance criteria will be met or if the service provider (employee or otherwise) fails to meet such performance criteria.

There were no stock option grants during the year ended December 31, 2025.

During the year ended December 31, 2024 and 2023 the weighted average assumptions shown below were used to calculate the weighted average grant date fair value of performance stock options grants under the Monte Carlo model.

	Year Ended December 31,	
	2024	2023
Weighted average exercise price - ($/share)	$ 5.96	$ 4.19
Expected life in years	6.7	6.4
Average expected volatility	71%	68%
Risk-free interest rate	4.28%	3.73%
Expected dividend yield	4.19%	5.97%
Weighted average grant date fair value - ($/share)	$ 3.27	$ 2.29

Performance stock options activity associated with the Monte Carlo model for the year ended December 31, 2025 is provided below:

	Number of Shares Underlying Options		Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term		Aggregate Intrinsic Value
	(in thousands)			*(in years)*		*(in thousands)*
Outstanding at January 1, 2025	1,118	$	5.32			
Unvested shares forfeited	(21)		6.41			
Outstanding at December 31, 2025	1,097	$	5.30	7.6	$	79
Exercisable at December 31, 2025	333	$	4.21	6.8	$	79

The intrinsic value of a performance stock option awards is the amount that the current market value of the underlying stock exceeds the exercise price of the award.

As of December 31, 2025, unrecognized compensation cost related to outstanding performance stock option awards was $0.6 million, which is expected to be recognized over a weighted average period of 1.27 years.

The Company’s regular stock options (stock options without a performance condition) awards associated with the Black-Scholes model were all exercised in 2024. The intrinsic value of a stock option is the amount that the current market value of the underlying stock exceeds the exercise price of the option. The intrinsic value of stock options exercised in 2024 and 2023 was $0.5 million and $0.6 million, respectively.

Restricted shares

Restricted stock granted to employees will vest over a period determined by the Compensation Committee that is generally a three-year period, vesting in three equal parts on the anniversaries following the date of the grant. Restricted stock granted to directors will vest on the earlier of (i) the first anniversary of the date of grant and (ii) the first annual meeting of stockholders following the date of grant (but not less than fifty (50) weeks following the date of grant).

The following is the activity for the Company's restricted stock for the year ended December 31, 2025:

	Restricted Stock		Weighted Average Grant Date Fair Value
	(in thousands)		
Non-vested shares outstanding at January 1, 2025	1,352	$	5.41
Awards granted	1,461		3.36
Awards vested	(623)		5.39
Awards forfeited	(226)		4.15
Non-vested shares outstanding at December 31, 2025	1,964	$	4.03

The total fair value of vested restricted stock awards during 2025, 2024 and 2023 was $2.2 million, $5.0 million, and $1.5 million, respectively. The weighted average grant date fair value per share of restricted stock awards, which vested during 2025, 2024 and 2023, was $5.39, $4.42 and $3.92, respectively.

As of December 31, 2025, unrecognized compensation cost related to restricted stock totaled $3.8 million and is expected to be recognized over a weighted average period of less than 1.41 years.

RSUs were issued to directors, officers and employees of TransGlobe in the ordinary course of business prior to the TransGlobe Acquisition. Each RSU vests annually over a three-year period.

RSU activity for the year ended December 31, 2025 is presented in the table below:

	Restricted Stock	Weighted Average Conversion Date Fair Value
	(in thousands)	
Non-vested shares outstanding at January 1, 2025	174	$ 5.01
Awards granted	331	3.36
Awards vested	(82)	4.78
Awards forfeited	(17)	3.36
Non-vested shares outstanding at December 31, 2025	406	$ 3.79

The total fair value of vested RSU awards during 2025 was $0.3 million. The weighted average grant date fair value per share of RSU, which vested during 2025, was $4.78.

As of December 31, 2025, unrecognized compensation cost related to RSUs totaled $1.7 million and is expected to be recognized over a weighted average period of 0.75 years.

During the year ended December 31, 2025, 194,771 shares were added to treasury as a result of tax withholding on the vesting of restricted stock and RSU's.

PSUs are similar to RSUs except that they originally contained a performance factor affecting the vesting percentage. For the PSUs that remained outstanding following the effective time of the TransGlobe Acquisition, the applicable vesting percentage was determined by the TransGlobe Board of Directors to be 200% for PSUs granted in 2022 and 2023; and 64.4% for PSUs granted in 2024. All PSUs granted vest on the third anniversary of their grant date.

PSU activity for the year ended December 31, 2025 is presented in the table below:

	Restricted Stock	Weighted Average Conversion Date Fair Value
	(in thousands)	
Non-vested shares outstanding at January 1, 2025	9	$ 4.27
Awards vested	(9)	4.27
Non-vested shares outstanding at December 31, 2025	—	$ —

During the year ended December 31, 2025, 3,671 shares were added to treasury shares as a result of tax withholding on the vesting of PSU's.

DSUs are similar to RSUs, except that they become fully vested on the date of grant and are only issued to directors of the Company. Distributions under the DSU plan do not occur until the retirement of the DSU holder from the Company's Board of Directors. At December 31, 2025, there are approximately 101,313 DSUs outstanding, which are vested but not converted.

Stock appreciation rights ("SARs")

SARs may be granted under the VAALCO Energy, Inc. 2016 Stock Appreciation Rights Plan and the 2020 Plan. A SAR is the right to receive a cash amount equal to the spread with respect to a share of common stock upon the exercise of the SAR. The spread is the difference between the SAR exercise price per share specified in the SAR award (that may not be less than the fair market value of the Company's common stock on the date of grant) and the fair market value per share of the Company's common stock on the date of exercise of the SAR. SARs granted to participants will become exercisable over a period determined by the Compensation Committee of the Company's Board of Directors. In addition, SARs will become exercisable upon a change in control, unless provided otherwise by the Compensation Committee of the Company's Board of Directors.

SARs are considered liabilities under US GAAP and the awards are measured at fair value on the grant date and remeasured at fair value until the award is settled.

The intrinsic value of a SAR is the amount that the current market value of the underlying stock exceeds the exercise price of the award. The intrinsic value of SARs exercised in 2024 and 2023 was $0.2 million, and 0.4 million respectively. During the years ended December 31, 2025 and 2024, the Company did not grant SARs to employees or directors. On February 28, 2024, all remaining SAR awards were exercised.

Other Benefit Plans

The Company has adopted forms of change in control agreements for certain named executive officers of the Company as well as a severance plan for its Houston-based non-executive employees. Upon a termination of a participant's employment by the Company without cause or a resignation by the participant for good reason three months prior to a change in control or six months following a change in control, executives and officers with change in control agreements will be entitled to receive 100% and 50%, respectively, of the participant's base salary and continued participation in the Company's group health plans for the participant and his or her eligible spouse and other dependents for six months. In addition, certain named executive officers will receive 75% of their target bonus. Some of the named executive officers are also entitled to severance payments under their employment agreements.

17. RELATED PARTY TRANSACTIONS

VAALCO has entered into various agreements with related parties. The Company paid approximately $0.3 million and $0.2 million to these related parties for each of the years ended December 31, 2025 and 2024, respectively. The amounts in both 2025 and 2024 were primarily for contract engineering services paid to an entity owned and controlled by a related party of an officer of the Company.

18. OTHER COMPREHENSIVE INCOME (LOSS)

At December 31, 2025, the Company's accumulated other comprehensive loss was $0.5 million. All of the Company's other comprehensive income (loss) arises from the currency translation of VAALCO Energy Canada, Inc. to USD.

The components of accumulated other comprehensive income (loss) are as follows:

	Currency Translation Adjustments
	(in thousands)
Balance at December 31, 2023	$ 2,880
Amounts reclassified from accumulated other comprehensive loss	(7,842)
Balance at December 30, 2024	$ (4,962)
Amounts reclassified from accumulated other comprehensive income	4,464
Balance at December 31, 2025	$ (498)

19. SEGMENT INFORMATION

The Company's operations are based in Gabon, Egypt, Cote d'Ivoire, Canada and Equatorial Guinea. Each of the reportable operating segments are organized and managed based upon geographic location. The Company's Chief Executive Officer, who is the chief operating decision maker ("CODM") evaluates segment performance based on the operation of each geographic segment separately primarily based on Operating income (loss) and allocates financial and capital resources for each segment predominantly in the annual budget and forecasting process. The CODM also considers budget-to-actual variances on a quarterly basis for the performance measure when making decisions about allocating capital and personnel to the segments.

The operations of all segments include exploration for and production of hydrocarbons where commercial reserves have been found and developed. Revenues are based on the location of hydrocarbon production. Corporate and other is primarily corporate and operations support costs that are not allocated to the reportable operating segments and are shown in the tables to reconcile the business segments to consolidated totals. No transactions occurred between operating segments. "Other operating income (expense)" below are those items that are included in Net income (loss) but are not regularly provided to the CODM, or are reported to the CODM but are not considered to be significant segment expenses.

Due to the quantity of active oil and natural gas purchasers in the markets where it produces hydrocarbons, the Company does not foresee any difficulty with selling its hydrocarbon production at fair market prices.

Segment activity of continuing operations for the years ended December 31, 2025, 2024 and 2023 and long-lived assets and segment assets at December 31, 2025 and 2024 are as follows:

	Year Ended December 31, 2025						
(in thousands)	**Gabon**	**Egypt**	**Canada**	**Equatorial Guinea**	**Cote d'Ivoire**	**Corporate and Other**	**Total**
Revenues:							
Crude oil, natural gas and natural gas liquids sales	$ 181,738	$ 139,963	$ 19,174	$ —	$ 18,397	$ —	$ 359,272
Operating costs and expenses:							
Production expense	84,677	53,539	8,458	1,561	9,941	1	158,177
Exploration expense	3,799	2,409	—	—	2,706	—	8,914
Depreciation, depletion and amortization	48,739	36,649	13,485	—	10,134	971	109,978
Impairment loss on assets held for sale	—	—	67,224	—	—	—	67,224
General and administrative expense	1,684	545	136	282	2,138	28,304	33,089
Credit (recovery) losses and other	(792)	(228)	—	1,126	—	—	106
Total operating costs and expenses	138,107	92,914	89,303	2,969	24,919	29,276	377,488
Other operating income (expense), net	18	—	—	—	(2,409)	—	(2,391)
Operating income (loss)	43,649	47,049	(70,129)	(2,969)	(8,931)	(29,276)	(20,607)
Other income (expense):							
Derivative instruments loss, net	—	—	—	—	—	2,876	2,876
Interest expense, net	(3,443)	(862)	—	—	(3,117)	(821)	(8,243)
Bargain purchase gain	—	—	—	—	—	—	—
Other income (expense), net	(1,096)	155	444	(5)	325	(418)	(595)
Total other income (expense), net	(4,539)	(707)	444	(5)	(2,792)	1,637	(5,962)
Income (loss) before income taxes	39,110	46,342	(69,685)	(2,974)	(11,723)	(27,639)	(26,569)
Income tax (benefit) expense	17,959	21,358	—	—	(22,631)	(1,864)	14,822
Net income (loss)	$ 21,151	$ 24,984	$ (69,685)	$ (2,974)	$ 10,908	$ (25,775)	$ (41,391)
Consolidated capital expenditures	$ 61,739	$ 28,768	$ 1,588	$ 607	$ 143,186	$ 526	$ 236,414

	Year Ended December 31, 2024						
(in thousands)	Gabon	Egypt	Canada	Equatorial Guinea	Côte d'Ivoire	Corporate and Other	Total
Revenues:							
Crude oil, natural gas and natural gas liquids sales	$ 205,954	$ 145,966	$ 31,986	$ —	$ 95,082	$ —	$ 478,988
Operating costs and expenses:							
Production expense	62,234	50,770	11,301	1,173	38,017	5	163,500
Exploration expense	—	48	—	—	—	—	48
Depreciation, depletion and amortization	50,679	33,458	19,309	—	38,771	817	143,034
General and administrative expense	1,679	70	(206)	305	1,701	26,135	29,684
Credit (recovery) losses and other	812	4,813	—	679	—	—	6,304
Total operating costs and expenses	115,404	89,159	30,404	2,157	78,489	26,957	342,570
Other operating income (expense), net	(24)	—	102	—	—	—	78
Operating income (loss)	90,526	56,807	1,684	(2,157)	16,593	(26,957)	136,496
Other income (expense):							
Derivative instruments gain (loss), net	—	—	—	—	(533)	(212)	(745)
Interest (expense) income, net	(4,694)	(1,489)	(46)	—	313	2,184	(3,732)
Bargain Purchase Gain	—	—	—	—	—	13,532	13,532
Other income (expense), net	(1,635)	(204)	225	(7)	(1)	(4,132)	(5,754)
Total other income (expense), net	(6,329)	(1,693)	179	(7)	(221)	11,372	3,301
Income (loss) before income taxes	84,197	55,114	1,863	(2,164)	16,372	(15,585)	139,797
Income tax (benefit) expense	48,026	30,648	—	—	4,229	(1,596)	81,307
Net income (loss)	$ 36,171	$ 24,466	$ 1,863	$ (2,164)	$ 12,143	$ (13,989)	$ 58,490
Consolidated capital expenditures	$ 22,579	$ 11,364	$ 25,828	$ 641	$ 44,435	$ 4,592	$ 109,439

(in thousands)	Gabon	Egypt	Canada	Equatorial Guinea	Corporate and Other	Total
	Year Ended December 31, 2023					
Revenues:						
Crude oil, natural gas and natural gas liquids sales	$ 260,346	$ 161,049	$ 33,671	$ —	$ —	$ 455,066
Operating costs and expenses:						
Production expense	87,131	54,779	9,463	1,481	303	153,157
FPSO demobilization and other costs	7,484	—	—	—	—	7,484
Exploration expense	51	1,914	—	—	—	1,965
Depreciation, depletion and amortization	62,622	35,095	17,398	—	187	115,302
General and administrative expense	1,769	974	—	416	20,681	23,840
Credit (recovery) losses and other	(10,596)	5,182	—	508	—	(4,906)
Total operating costs and expenses	148,461	97,944	26,861	2,405	21,171	296,842
Other operating income (expense), net	(55)	(241)	729	—	—	433
Operating income (loss)	111,830	62,864	7,539	(2,405)	(21,171)	158,657
Other income (expense):						
Derivative instruments loss, net	—	—	—	—	232	232
Interest income, net	(5,563)	(2,110)	(4)	—	1,225	(6,452)
Bargain purchase gain measurement period adjustment	—	—	—	—	(1,412)	(1,412)
Other income (expense), net	(820)	—	2	(6)	(70)	(894)
Total other income (expense), net	(6,383)	(2,110)	(2)	(6)	(25)	(8,526)
Income (loss) before income taxes	105,447	60,754	7,537	(2,411)	(21,196)	150,131
Income tax (benefit) expense	50,692	32,859	—	—	6,226	89,777
Net income (loss)	$ 54,755	$ 27,895	$ 7,537	$ (2,411)	$ (27,422)	$ 60,354
Consolidated capital expenditures	$ 17,011	$ 37,866	$ 16,809	$ —	$ 950	$ 72,636

(in thousands)	Gabon	Egypt	Canada[a]	Equatorial Guinea	Côte d'Ivoire	Corporate and Other	Total
Long-lived assets:							
As of December 31, 2025	**$ 177,030**	**$ 138,839**	**$ —**	**$ 11,248**	**$ 254,307**	**$ 4,671**	**$ 586,095**
As of December 31, 2024	$ 153,576	$ 149,129	$ 104,891	$ 10,641	$ 114,756	$ 5,110	$ 538,103

[a] At December 31, 2025, the Company classified $31.8 million of net Crude oil, natural gas and NGLs properties as "Noncurrent Assets held for sale" on the Consolidated Balance Sheet.

(in thousands)	Gabon	Egypt	Canada	Equatorial Guinea	Côte d'Ivoire	Corporate and Other	Total
Total assets:							
As of December 31, 2025	**$ 315,787**	**$ 182,023**	**$ 35,982**	**$ 13,631**	**$ 283,768**	**$ 82,184**	**$ 913,375**
As of December 31, 2024	$ 300,568	$ 269,905	$ 113,310	$ 12,331	$ 187,264	$ 71,572	$ 954,950

20. SUBSEQUENT EVENTS

In February 2026, the Company became the operator with a 60% working interest in the Kossipo field on the CI-40 Block with a field development plan to be completed in the second half of 2026.

SUPPLEMENTAL INFORMATION ON CRUDE OIL, NATURAL GAS AND NGLs PRODUCING ACTIVITIES (UNAUDITED)

This supplemental information is presented in accordance with certain provisions of ASC Topic 932 – *Extractive Activities- Oil and Natural Gas*. The geographic areas reported are the U.S. (North America), which includes the producing properties in offshore Gabon and Cote d'Ivoire (Africa), and onshore in Egypt as well as, prior to the Canada Asset Divestment (defined below), producing properties in Canada.

In December 2025, the Company's Board of Directors approved the sale of the Company's oil and gas properties in Canada. As of December 31, 2025, certain assets and liabilities associated with our Canada Asset Divestment were classified as held for sale on our Consolidated Balance Sheet. On February 4, 2026, the Company entered into an asset purchase agreement to sell all of our operating assets in Canada. The sale was completed on February 16, 2026 with an effective date of February 1, 2026 (the "Canada Asset Divestment"). As of December 31, 2025, all of our proved developed and proved undeveloped reserves in Canada are attributed to assets held for sale.

Our reserves information was evaluated by the independent petroleum engineering firm, Netherland, Sewell & Associates, Inc. ("NSAI"). Prior to 2025, reserves information for Canada was independently evaluated by GLJ Ltd. ("GLJ"). The proved reserve quantities are calculated based on our NRI.

Costs Incurred for Acquisition, Exploration and Development Activities

Costs incurred during the year:	**Gabon**	**Egypt**	**Canada**	**Cote d'Ivoire**	**Total**
Year Ended December 31, 2025			*(in thousands)*		
Exploration costs - expensed	**$ 3,799**	**$ 2,409**	**$ —**	**$ 2,706**	**$ 8,914**
Exploration costs - capitalized	**—**	**1,201**	**—**	**—**	**1,201**
Acquisition of properties	**—**	**—**	**—**	**3,034**	**3,034**
Development costs	**61,739**	**27,567**	**1,588**	**143,186**	**234,080**
Total	**$ 65,538**	**$ 31,177**	**$ 1,588**	**$ 148,926**	**$ 247,229**

	Gabon	**Egypt**	**Canada**	**Cote d'Ivoire**	**Total**
Year Ended December 31, 2024			*(in thousands)*		
Exploration costs - expensed	$ —	$ 48	$ —	$ —	$ 48
Acquisition of properties	—	—	—	107,089	107,089
Development costs	22,579	11,364	25,828	44,435	104,206
Total	$ 22,579	$ 11,412	$ 25,828	$ 151,524	$ 211,343

	Gabon	**Egypt**	**Canada**	**Total**
Year Ended December 31, 2023[(1)]		*(in thousands)*		
Exploration costs - expensed	$ 51	$ 1,914	$ —	$ 1,965
Acquisition of properties	—	—	—	—
Development costs	17,011	37,866	16,809	71,686
Total	$ 17,062	$ 39,780	$ 16,809	$ 73,651

(1) For Cote d'Ivoire, all activity pertains to the period from April 30, 2024 to December 31, 2024 related to the Svenska Acquisition.

Capitalized Costs Relating to crude oil, natural gas and NGLs Producing Activities

Capitalized costs pertain to the producing activities in Gabon, Egypt, Cote d'Ivoire and Canada and to undeveloped leasehold in Gabon, Egypt, Cote d'Ivoire, Canada and Equatorial Guinea.

	As of December 31,	
	2025	2024
Capitalized costs:	*(in thousands)*	
Properties not being amortized	**$ 348,641**	$ 155,825
Properties being amortized	**1,147,433**	1,588,699
Total capitalized costs	**$ 1,496,074**	$ 1,744,524
Less accumulated depletion, amortization and impairment	**(884,747)**	(1,214,465)
Net capitalized costs	**$ 611,327**	$ 530,059

Results of Operations for crude oil, natural gas and NGLs Producing Activities

Year Ended December 31, 2025	**Gabon**	**Egypt**	**Canada**	**Cote d'Ivoire**	**Total**
			(In thousands)		
Revenues	**$ 181,738**	**$ 139,963**	**$ 19,174**	**$ 18,397**	**$ 359,272**
Production costs and other expense [(1)]	**(84,677)**	**(53,539)**	**(8,458)**	**(9,941)**	**(156,615)**
Depreciation, depletion, amortization	**(48,739)**	**(36,649)**	**(13,485)**	**(10,134)**	**(109,007)**
Impairment loss on assets held for sale	**—**	**—**	**(67,224)**	**—**	**(67,224)**
Exploration expenses	**(3,799)**	**(2,409)**	**—**	**(2,706)**	**(8,914)**
Other operating expense	**18**	**—**	**—**	**(2,409)**	**(2,391)**
Income tax benefit (expense)	**(22,748)**	**(21,813)**	**—**	**12,525**	**(32,036)**
Results from crude oil and natural gas producing activities	**$ 21,793**	**$ 25,553**	**$ (69,993)**	**$ 5,732**	**$ (16,915)**

Year Ended December 31, 2024[(2)]	**Gabon**	**Egypt**	**Canada**	**Cote d'Ivoire**	**Total**
			(In thousands)		
Crude oil and natural gas sales	$ 205,954	$ 145,966	$ 31,986	$ 95,082	$ 478,988
Production costs and other expense [(1)]	(62,234)	(50,770)	(11,301)	(38,017)	(162,322)
Depreciation, depletion, amortization	(50,679)	(33,458)	(19,309)	(38,771)	(142,217)
Exploration expenses	—	(48)	—	—	(48)
Other operating expense	(24)	—	102	—	78
Income tax benefit (expense)	(80,488)	(34,300)	—	(2,587)	(117,375)
Results from crude oil and natural gas producing activities	$ 12,529	$ 27,390	$ 1,478	$ 15,707	$ 57,104

Year Ended December 31, 2023	**Gabon**	**Egypt**	**Canada**	**Total**
		(In thousands)		
Crude oil and natural gas sales	$ 260,346	$ 161,049	$ 33,671	$ 455,066
Production costs and other expense [(1)]	(94,615)	(54,779)	(9,463)	(158,857)
Depreciation, depletion, amortization	(62,622)	(35,095)	(17,398)	(115,115)
Exploration expenses	(51)	(1,914)	—	(1,965)
Other operating expense	(55)	(241)	729	433
Income tax benefit (expense)	(67,982)	(37,271)	—	(105,253)
Results from crude oil and natural gas producing activities	$ 35,021	$ 31,749	$ 7,539	$ 74,309

(1) Includes local general and administrative expenses but excludes corporate general and administrative expenses and allocated corporate overhead.
(2) For Cote d'Ivoire, all activity pertains to the period from April 30, 2024 to December 31, 2024 related to the Svenska Acquisition.

Estimated Quantities of Proved Reserves

The estimation of net recoverable quantities of crude oil, natural gas and NGLs is a highly technical process that is based upon several underlying assumptions that are subject to change. See "*Item 1A. Risk Factors*" and "*Item 7. Management's Discussion and Analysis of Financial Condition, Cash Flows and Liquidity – Critical Accounting Policies and Estimates – Successful Efforts Method of Accounting for crude oil, natural gas and NGLs Activities.*" For a discussion of the reserve estimation process, including internal controls, see "*Item 1. Business – Reserve Information*."

	Oil				
Proved reserves:	**Gabon (MBbls)**	**Egypt (MBbls)**	**Canada (MBbls)**	**Cote d'Ivoire (MBbls)**	**Total (MBbls)**
Balance at January 1, 2023	10,219	8,577	3,607	—	22,403
Production	(3,197)	(2,771)	(334)	—	(6,302)
Purchase of reserves	—	—	—	—	—
Extensions and discoveries	—	93	810	—	903
Revisions of previous estimates	2,042	4,693	(652)	—	6,083
Balance at December 31, 2023	9,064	10,592	3,431	—	23,087
Production	(2,783)	(2,585)	(348)	(1,054)	(6,770)
Purchase of reserves	—	—	—	15,288	15,288
Extensions and discoveries	—	—	251	—	251
Revisions of previous estimates	4,782	1,441	(569)	1,018	6,672
Balance at December 31, 2024	11,063	9,448	2,765	15,252	38,528
Production	(2,535)	(2,730)	(214)	(111)	(5,590)
Purchase of reserves	—	—	—	—	—
Extensions and discoveries	1,195	34	—	—	1,229
Revisions of previous estimates	278	1,862	(209)	1,870	3,801
Balance at December 31, 2025	**10,001**	**8,614**	**2,342**	**17,011**	**37,968**

	Oil				
	Gabon (MBbls)	**Egypt (MBbls)**	**Canada (MBbls)**	**Cote d'Ivoire (MBbls)**	**Total (MBbls)**
Year-end proved developed reserves:					
2025	**5,287**	**8,177**	**1,179**	**—**	**14,643**
2024	6,830	8,962	1,480	118	17,390
2023	8,053	10,141	1,309	—	19,503
2022	10,219	8,001	1,722	—	19,942
Year-end proved undeveloped reserves:					
2025	**4,714**	**437**	**1,163**	**17,011**	**23,325**
2024	4,233	486	1,286	15,134	21,139
2023	1,011	451	2,122	—	3,584
2022	—	576	1,885	—	2,461

	Natural Gas				
Proved reserves:	**Gabon (MMcf)**	**Egypt (MMcf)**	**Canada (MMcf)**	**Cote d'Ivoire (MMcf)**	**Total (MMcf)**
Balance at January 1, 2023	—	—	16,539	—	16,539
Production	—	—	(1,528)	—	(1,528)
Purchase of reserves	—	—	—	—	—
Extensions and discoveries	—	—	3,219	—	3,219
Revisions of previous estimates	—	—	(1,298)	—	(1,298)
Balance at December 31, 2023	—	—	16,932	—	16,932
Production	—	—	(1,532)	(26)	(1,558)
Purchase of reserves	—	—	—	6,830	6,830
Extensions and discoveries	—	—	876	—	876
Revisions of previous estimates	—	—	(196)	(253)	(449)
Balance at December 31, 2024	—	—	16,080	6,551	22,631
Production	—	—	(1,449)	—	(1,449)
Extensions and discoveries	—	—	—	—	—
Revisions of previous estimates	—	—	(2,422)	403	(2,019)
Balance at December 31, 2025	**—**	**—**	**12,209**	**6,954**	**19,163**

	Natural Gas				
	Gabon (MMcf)	**Egypt (MMcf)**	**Canada (MMcf)**	**Cote d'Ivoire (MMcf)**	**Total (MMcf)**
Year-end proved developed reserves:					
2025	**—**	**—**	**9,059**	**—**	**9,059**
2024	—	—	10,490	47	10,537
2023	—	—	9,011	—	9,011
2022	—	—	11,023	—	11,023
Year-end proved undeveloped reserves:					
2025	**—**	**—**	**3,150**	**6,954**	**10,104**
2024	—	—	5,590	6,504	12,094
2023	—	—	7,921	—	7,921
2022	—	—	5,516	—	5,516

Proved reserves:	NGLs Gabon (MBbls)	Egypt (MBbls)	Canada (MBbls)	Cote d'Ivoire (MBbls)	Total (MBbls)
Balance at January 1, 2023	—	—	2,797	—	2,797
Production	—	—	(270)	—	(270)
Purchase of reserves	—	—	—	—	—
Extensions and discoveries	—	—	505	—	505
Revisions of previous estimates	—	—	(295)	—	(295)
Balance at December 31, 2023	—	—	2,737	—	2,737
Production	—	—	(267)	—	(267)
Purchase of reserves	—	—	—	—	—
Extensions and discoveries	—	—	142	—	142
Revisions of previous estimates	—	—	68	—	68
Balance at December 31, 2024	—	—	2,680	—	2,680
Production	—	—	(212)	—	(212)
Extensions and discoveries	—	—	—	—	—
Revisions of previous estimates	—	—	(687)	—	(687)
Balance at December 31, 2025	**—**	**—**	**1,781**	**—**	**1,781**

	NGLs Gabon (MBbls)	Egypt (MBbls)	Canada (MBbls)	Cote d'Ivoire (MBbls)	Total (MBbls)
Year-end proved developed reserves:					
2025	—	—	1,329	—	1,329
2024	—	—	1,744	—	1,744
2023	—	—	1,449	—	1,449
2022	—	—	1,855	—	1,855
Year-end proved undeveloped reserves:					
2025	—	—	452	—	452
2024	—	—	936	—	936
2023	—	—	1,289	—	1,289
2022	—	—	942	—	942

Proved reserves:	Total Reserves (1) Gabon (MBoe)	Egypt (MBoe)	Canada (MBoe)	Cote d'Ivoire (MBoe)	Total (MBoe)
Balance at January 1, 2023	10,219	8,577	9,161	—	27,957
Production	(3,197)	(2,771)	(859)	—	(6,827)
Purchase of reserves	—	—	—	—	—
Extensions and discoveries	—	93	1,852	—	1,945
Revisions of previous estimates	2,042	4,693	(1,163)	—	5,572
Balance at December 31, 2023	9,064	10,592	8,991	—	28,647
Production	(2,783)	(2,585)	(870)	(1,058)	(7,296)
Purchase of reserves	—	—	—	16,465	16,465
Extensions and discoveries	—	—	539	—	539
Revisions of previous estimates	4,782	1,441	(534)	974	6,663
Balance at December 31, 2024	11,063	9,448	8,126	16,381	45,018
Production	(2,535)	(2,730)	(667)	(111)	(6,043)
Purchase of reserves	—	—	—	—	—
Extensions and discoveries	1,195	34	—	—	1,229
Revisions of previous estimates	278	1,862	(1,301)	1,940	2,779
Balance at December 31, 2025	**10,001**	**8,614**	**6,158**	**18,210**	**42,983**

(1) To convert Natural Gas to MBoe, MMcf is divided by 6 for Canada reserves, and MMcf is divided by 5.8 for Cote d'Ivoire reserves.

	Total Reserves(1) Gabon (MBoe)	Egypt (MBoe)	Canada (MBoe)	Cote d'Ivoire (MBoe)	Total (MBoe)
Year-end proved developed reserves:					
2025	**5,287**	**8,177**	**4,018**	**—**	**17,482**
2024	6,830	8,962	4,972	126	20,890
2023	8,053	10,141	4,260	—	22,454
2022	10,219	8,001	5,414	—	23,634
Year-end proved undeveloped reserves:					
2025	**4,714**	**437**	**2,140**	**18,210**	**25,501**
2024	4,233	486	3,154	16,255	24,128
2023	1,011	451	4,731	—	6,193
2022	—	576	3,746	—	4,322

(1) To convert Natural Gas to MBoe, MMcf is divided by 6 for Canada reserves, and MMcf is divided by 5.8 for Cote d'Ivoire reserves.

Year Ended December 31, 2025

Revisions
During 2025, the Company had net positive revisions of prior estimates of 2.8 MMBoe. These upward revisions include an increase of 1.9 MMBoe from our Egypt segment resulting from a combination of continued development activity including active in-field drilling, workovers as well as improved, forecasted well performance. In addition, we had an increase of 1.9 MMBoe from our Cote d’Ivoire segment which reflects improved recovery based on technical analysis of the upcoming Phase 5 drilling campaign. The Gabon segment also contributed to an increase of 0.3 MMBoe based on improved production performance. The upward revisions were offset by negative revisions of 1.3 MMBoe in Canada due to wells that were not reasonably expected to be developed within the five-year timeframe in accordance with the SEC guidance.

Extensions and discoveries
During 2025, the Company added 1.2 MMBoe of proved reserves through extensions, discoveries, and other additions related to the Phase 3 drilling campaign in Gabon.

Year Ended December 31, 2024

Purchases of reserves in place
For the balance at December 31, 2024, purchases of reserves in place included 16.5 MMBoe of proved reserves in Cote d'Ivoire, associated with our acquisition of Svenska Petroleum Exploration Aktiebolag ("Svenska"), and as a result, Svenska's primary asset: a 27.39% non-operated working interest in the deepwater producing Baobab field in Block CI-40.

Extensions and discoveries
For the balance at December 31, 2024, extensions and discoveries included 0.5 MMBoe of proved reserves in Canada, primarily related to the drilling of new wells.

Revisions
In 2024, operations in Gabon had 4.8 MMBoe of reserves added through positive revisions of previous estimates mainly due to performance and development activities. For Egypt, we had 1.4 MMBoe of reserves added through positive revisions of previous estimates primarily as a result of our workover programs. For Canada, we had 0.5 MMBoe of negative revisions of previous estimates primarily due to performance adjustments of existing wells. For the balance at December 31, 2024, operations in Cote d'Ivoire included 1.0 MMBoe in positive revisions of reserves due to improved field performance.

Year Ended December 31, 2023

Revisions
In 2023, operations in Gabon had 2.0 MMBoe of reserves added through positive revisions of previous estimates. 2.8 MMBoe of the positive revisions were due to performance offset by 0.8 MMBoe of negative revisions through price. For Egypt at December 31, 2023, 4.7 MMBoe of reserves were added through positive revisions of previous estimates. 5.3 MMBoe of the positive revisions were due to performance offset by 0.6 MMBoe of negative revisions through price. For the balance at December 31, 2023, operations in Canada included 1.2 MMBoe in negative revisions of reserves due to performance adjustments of existing wells.

Extensions and discoveries
For the balance at December 31, 2023, extensions and discoveries included 0.1 MMBoe of proved reserves in Egypt, primarily related to operational improvements and the drilling of new wells and 1.9 MMBoe of proved reserves in Canada, primarily related to the drilling of new wells.

In accordance with the guidelines of the SEC, the Company does not book proved reserves on discoveries until such time as a development plan has been prepared for the discovery indicating that the development well will be drilled within five years from the date of its initial booking. Additionally, the development plan is required to have the approval of the joint venture owners in the discovery. Furthermore, if a government agreement that the reserves are commercial is required to develop the block, this approval must have been received prior to booking any reserves.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Crude Oil Reserves

The information that follows has been developed pursuant to procedures prescribed under GAAP and uses reserve and production data estimated by independent petroleum consultants. The information may be useful for certain comparison purposes, but should not be solely relied upon in evaluating its or the Company's performance.

In accordance with the guidelines of the SEC, the estimates of future net cash flow from the properties and the present value thereof are made using crude oil, natural gas and NGLs contract prices using a twelve month average of beginning of month prices and are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. The future cash flows are also based on costs in existence at the dates of the projections, excluding Gabon royalties, and the interests of other Consortium members. Future production costs do not include overhead charges allowed under joint operating agreements or headquarters general and administrative overhead expenses. However, all future costs related to future property abandonment when the wells become uneconomic to produce are included in future development costs for purposes of calculating the standardized measure of discounted net cash flows. There were no discounted future net cash flows attributable to U.S. properties as of December 31, 2025, 2024 and 2023.

	International				
(In thousands)	**Gabon**	**Egypt**	**Canada**	**Cote d'Ivoire**	**Total**
Year Ended December 31, 2025					
Future cash inflows	**$ 666,072**	**$ 556,434**	**$ 197,628**	**$ 1,301,697**	**$ 2,721,831**
Future production costs	**(390,226)**	**(302,960)**	**(82,400)**	**(445,893)**	**(1,221,479)**
Future development costs (1)	**(156,136)**	**(53,308)**	**(59,664)**	**(348,759)**	**(617,867)**
Future income tax expense	**(86,489)**	**(59,725)**	**—**	**(125,346)**	**(271,560)**
Future net cash flows	**33,221**	**140,441**	**55,564**	**381,699**	**610,925**
Discount to present value at 10% annual rate	**(1,660)**	**(22,389)**	**(27,793)**	**(149,074)**	**(200,916)**
Standardized measure of discounted future net cash flows	**$ 31,561**	**$ 118,052**	**$ 27,771**	**$ 232,625**	**$ 410,009**
Year Ended December 31, 2024					
Future cash inflows	$ 912,914	$ 782,814	$ 269,195	$ 1,423,441	$ 3,388,364
Future production costs	(470,775)	(370,085)	(123,367)	(446,645)	(1,410,872)
Future development costs (1)	(221,743)	(93,426)	(62,629)	(466,407)	(844,205)
Future income tax expense	(134,216)	(144,883)	—	(205,167)	(484,266)
Future net cash flows	86,180	174,420	83,199	305,222	649,021
Discount to present value at 10% annual rate	(13,169)	(39,281)	(36,092)	(181,079)	(269,621)
Standardized measure of discounted future net cash flows	$ 73,011	$ 135,139	$ 47,107	$ 124,143	$ 379,400
Year Ended December 31, 2023					
Future cash inflows	$ 761,919	$ 828,418	$ 352,666	$ —	$ 1,943,003
Future production costs	(410,425)	(383,957)	(129,317)	—	(923,699)
Future development costs (1)	(88,868)	(84,132)	(80,129)	—	(253,129)
Future income tax expense	(148,750)	(144,269)	—	—	(293,019)
Future net cash flows	113,876	216,060	143,220	—	473,156
Discount to present value at 10% annual rate	(6,052)	(54,313)	(70,857)	—	(131,222)
Standardized measure of discounted future net cash flows	$ 107,824	$ 161,747	$ 72,363	$ —	$ 341,934

(1) Includes costs expected to be incurred to abandon the properties, where applicable.

International income taxes represent amounts payable to the Governments of Gabon and Cote d'Ivoire on Profit Oil as final payment of corporate income taxes, and domestic income taxes (including other expenses treated as taxes).

Changes in Standardized Measure of Discounted Future Net Cash Flows

The following table sets forth the changes in standardized measure of discounted future net cash flows as follows:

	Year Ended December 31,		
	2025	2024	2023
		(in thousands)	
Balance at beginning of period	**$ 379,400**	$ 341,934	$ 624,465
Sales of crude oil and natural gas, net of production costs	**(192,861)**	(316,667)	(296,209)
Net changes in prices and production costs	**(279,298)**	18,385	(210,703)
Extensions and discoveries	**5,542**	9,156	28,849
Revisions of previous quantity estimates	**93,369**	145,177	139,856
Purchases	**—**	175,849	—
Changes in estimated future development costs	**18,844**	(94,003)	(92,641)
Development costs incurred during the period	**201,533**	28,676	—
Accretion of discount	**37,940**	45,917	62,447
Net change of income taxes	**139,391**	21,053	77,757
Change in production rates (timing) and other	**6,149**	3,923	8,113
Balance at end of period	**$ 410,009**	$ 379,400	$ 341,934

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond the Company’s control. Reserve engineering is a subjective process of estimating underground accumulations of crude oil, natural gas and NGLs that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of crude oil, natural gas and NGLs that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future crude oil, natural gas and NGLs sales prices may all differ from those assumed in these estimates. The standardized measure of discounted future net cash flow should not be construed as the current market value of the estimated crude oil, natural gas and NGLs reserves attributable to the properties. The information set forth in the foregoing tables includes revisions for certain reserve estimates attributable to proved properties included in the preceding year’s estimates. Such revisions are the result of additional information from subsequent completions and production history from the properties involved or the result of a decrease (or increase) in the projected economic life of such properties resulting from changes in product prices. Moreover, crude oil amounts shown for Gabon are recoverable under a service contract and the reserves in place at the end of the contract period remain the property of the Gabon government.

In accordance with the current SEC guidelines, estimates of future net cash flow from our properties and the present value thereof are made using the average of the first-day-of-the-month price for each of the twelve months of the year adjusted for quality, transportation fees and market differentials. Such prices are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations.

For 2025 and 2024, the average of such prices used for our reserve estimate were as follows:

	Year Ended December 31,	
	2025	2024
Crude Oil ($/Bbl)		
Gabon	$ 66.60	$ 81.08
Egypt	$ 57.66	$ 65.48
Cote d'Ivoire	$ 68.95	$ 79.70
Canada	$ 61.61	$ 69.12
Natural Gas ($/Mcf)		
Cote d'Ivoire	$ 2.77	$ 2.77
Canada	$ 1.07	$ 0.95
Natural Gas Liquids ($/Bbl)		
Canada		
Ethane	$ 2.90	$ 3.52
Propane	$ 19.67	$ 19.46
Butane	$ 25.88	$ 30.68
Condensates	$ 62.44	$ 69.59

Production Sharing Contracts

Under the Etame PSC in Gabon, the Gabonese government is the owner of all crude oil, natural gas and NGLs mineral rights. The right to produce the crude oil, natural gas and NGLs is stewarded by the Directorate Generale de Hydrocarbures and the Etame PSC was awarded by a decree. Pursuant to the contract, the Gabon government receives a fixed royalty rate of 13%. Originally, under the Etame PSC, Gabonese government was not anticipated to take physical delivery of its allocated production. Instead, the Company was authorized to sell the Gabonese government's share of production and remit the proceeds to the Gabonese government. Beginning in February 2018, the Gabonese government elected to take physical delivery of its allocated production volumes for Profit Oil. Please see further discussion in Note 6. Revenue.

The Etame Consortium maintains a Cost Account, which entitles it to receive a portion of the production remaining after deducting the 13% royalty so long as there are amounts remaining in the Cost Account ("Cost Recovery"). Prior to the PSC Extension, the Consortium was entitled to a 70% Cost Recovery Percentage. Under the PSC Extension, the Cost Recovery Percentage is increased to 80% for the ten-year period from September 17, 2018 through September 16, 2028. After September 16, 2028, the Cost Recovery Percentage returns to 70%. As payment of corporate income taxes, the Etame Consortium pays the government an allocation of the remaining Profit Oil production from the contract area ranging from 50% to 60% of the crude oil remaining after deducting the royalty and Cost Recovery. The percentage of Profit Oil paid to the government as tax is a function of production rates. However, when the Cost Account becomes substantially recovered, the Company only recovers ongoing operating expenses and new project capital expenditures, resulting in a higher tax rate. Also, because of the nature of the Cost Account, decreases in crude oil prices result in a higher number of barrels required to recover costs.

The Etame PSC allows for exploitation period through the carve-out of development areas, which include all producing fields in the Etame Marin block as well as additional undeveloped areas where reserves may exist. The PSC Extension extends the term for each of the three exploitation areas in the Etame Marin block for a period of ten years with effect from September 17, 2018, the effective date of the PSC Extension. The PSC Extension also grants the Etame Consortium the right for two additional extension periods of five years each. This compares to the economic end date of reserves under the current reserve report evaluated by the independent reserve engineering firm of Netherland, Sewell & Associates, Inc.

The PSC for Block P in Equatorial Guinea entitles the Company to receive up to 70% of any future production after royalty deduction so long as there are amounts remaining in the Cost Account. Royalty rates are 10-16% depending on production rates. The Etame Consortium pays the government an allocation of the remaining Profit Oil production from the contract area ranging from 10% to 60% of the crude oil remaining after deducting the royalty and Cost Recovery. The percentage of Profit Oil paid to the government as tax is a function of cumulative production. In addition, Equatorial Guinea imposes a 25% income tax on net profits. The Block P PSC provides for a discovery to be reclassified into a development area with a term of 25 years. At December 31, 2025, the Company has no SEC proved reserves related to Block P in Equatorial Guinea.

Egypt production is based on Dated Brent prices, less a quality differential and is shared with the Egyptian government through PSCs. When the price of oil increases, it takes fewer barrels to recover costs (Cost Oil or cost recovery barrels) which are assigned 100% to the Company. The PSCs provide for cost recovery per quarter up to a maximum percentage of total production. Timing differences often exist between the Company's recognition of costs and their recovery as the Company accounts for costs on an accrual basis, whereas cost recovery is determined on a cash basis. If the eligible cost recovery is less than the maximum defined cost recovery, the difference is defined as “excess”. In Egypt, depending on the PSCs, the Contractor's share of excess ranges between 5% and 15%. If the eligible cost recovery exceeds the maximum allowed percentage, the unclaimed cost recovery is carried forward to the next quarter. Typically, maximum Cost Oil ranges from 25% to 40% in Egypt. The balance of the production after maximum cost recovery is shared with the government (Profit Oil). Depending on the contract, the Egyptian government receives 67% to 84% of the profit oil. Production sharing splits are set in each contract for the life of the contract.

Under the Modernized Royalty Framework (the “MRF”) in Alberta, producers initially pay a flat royalty of 5% on production revenue from each producing well until payout, which is the point at which cumulative gross revenues from the well equals the applicable drilling and completion cost allowance. After payout, producers pay an increased royalty of up to 40% that will vary depending on the nature of the resource and market prices. Once the rate of production from a well is too low to sustain the full royalty burden, its royalty rate is gradually adjusted downward as production declines, eventually reaching a floor of 5%. The MRF applies to the hydrocarbons produced by wells spud or re-entered on or after January 1, 2017. The Royalty Guarantee Act (Alberta) came into effect in July 2019, amending the Mines and Minerals Act (Alberta) and guaranteeing no major changes to the oil and gas royalty structure for a period of 10 years.

Royalty rates for the production of privately owned oil and natural gas are negotiated between the producer and the resource owner. The Government of Alberta levies annual freehold mineral taxes for production from freehold mineral lands. On average, the tax levied in Alberta is 4% of revenues reported from freehold mineral title properties and is payable by the registered owner of the mineral rights.

The Company owns a 27.39% non-operated working interest in the deepwater producing Baobab field in Block CI-40, offshore Cote d’Ivoire in West Africa. Production generated from the Baobab field is shared under a PSC (the “Cote d'Ivoire PSC”). Under the Cote d’Ivoire PSC, the Company is entitled to a Cost Oil recovery percentage of up to 80% of total production. Profit Oil percentage ranges from 30% to 53% based on the range of daily total production. Cost Oil allows the Company to recover its capital and production costs and the costs carried by the Company on behalf of the government state oil company. Profit oil is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the government of Cote d'Ivoire. In addition, under the terms of the Cote d'Ivoire PSC, the tax payments to the Ivorian Government are deemed satisfied by its share of the Profit Oil.

Exhibit 4.1

DESCRIPTION OF SECURITIES

The following description sets forth certain material terms and provisions of our common stock, which is the only class of our securities registered under Section 12 of the Securities Exchange Act of 1934, as amended. This description also summarizes relevant provisions of Delaware law. The following summary does not purport to be complete and is subject to, and is qualified in its entirety by reference to, the applicable provisions of Delaware law and our Restated Certificate of Incorporation, as amended (the "Restated Certificate of Incorporation") and our Third Amended and Restated Bylaws (the "Bylaws"), as may be amended from time to time, copies of which are incorporated by reference as exhibits to the Annual Report on Form 10-K of which this Exhibit 4.1 is a part. In addition, you should be aware that the summary below does not give full effect to the terms of the provisions of statutory or common law, and we encourage you to read our Restated Certificate of Incorporation, our Bylaws and the applicable provisions of Delaware law for additional information.

Authorized Capital Stock

We are currently authorized to issue up to 160,000,000 shares of common stock, par value $0.10 per share and 500,000 shares of preferred stock, par value $25.00 per share. The number of shares of common stock issued and outstanding varies from time to time.

Common Stock

Holders of our common stock are entitled to cast one vote for each share held of record on each matter submitted to a vote of stockholders. There is no cumulative voting for the election of directors. Subject to the prior rights of any series of preferred stock which may from time to time be outstanding, if any, holders of our common stock are entitled to receive ratably dividends when, as and if declared by the board of directors out of funds legally available for such purpose and, upon the liquidation, dissolution or winding up of the company, are entitled to share ratably in all assets remaining after payment of liabilities and payment of accrued dividends and liquidation preferences on the preferred stock, if any. There are no redemption or sinking fund provisions that are applicable to our common stock. Except as otherwise required by law or the NYSE, the board of directors may issue shares of our common stock without stockholder approval, at any time and from time to time, to such persons and for such consideration as the board of directors deems appropriate. Holders of our common stock have no preemptive rights and have no rights to convert their common stock into any other securities. All outstanding shares of our common stock is validly authorized and issued, fully paid and nonassessable.

The issuance of any such preferred stock by our board of directors could adversely affect the rights of the holders of our common stock and, therefore, reduce the value of the common stock. The ability of the board of directors to issue preferred stock could discourage, delay, or prevent a takeover of us.

Anti-Takeover Effects of Provisions of Our Restated Certificate of Incorporation and Our Bylaws

Our Restated Certificate of Incorporation, Bylaws and Delaware law contain several provisions that may make the acquisition of control of us by means of a tender offer, open market purchases, a proxy fight, or otherwise more difficult.

Delaware Law

Section 203 of the Delaware General Corporation Law restricts certain transactions between a corporation organized under Delaware law or its majority-owned subsidiaries and any "interested stockholder," defined as any person who, together with the affiliates or associates of such person, beneficially owns 15% or more of the corporation's outstanding voting stock. Section 203 prevents, for a period of three years following the date that a person becomes an interested stockholder, the following types of transactions between the corporation and the interested stockholder, unless certain conditions are met:

- mergers or consolidations;
- sales, leases, exchanges or other transfers of 10% or more of the aggregate assets of the corporation;
- issuances or transfers by the corporation of any stock of the corporation which would have the effect of increasing the interested stockholder's proportionate share of the stock of any class or series of the corporation;
- any other transaction which has the effect of increasing the proportionate share of the stock of any class or series of the corporation which is owned by the interested stockholder; and
- receipt by the interested stockholder of the benefit, except proportionately as a stockholder, of loans, advances, guarantees, pledges or other financial benefits provided by the corporation.

The three-year ban does not apply if either the proposed transaction or the transaction by which the interested stockholder became an interested stockholder is approved by the board of directors of the corporation prior to the date such stockholder becomes an interested stockholder. Additionally, an interested stockholder may avoid the statutory restriction if, upon the consummation of the transaction whereby such stockholder becomes an interested stockholder, the stockholder owns at least 85% of the outstanding voting stock of the corporation without regard to those shares owned by the corporation's officers and directors or certain employee stock plans. Business combinations are also permitted within the three-year period if approved by the board of directors and authorized at an annual or special meeting of stockholders by the holders of at least 66 and 2/3 % of the outstanding voting stock not owned by the interested stockholder. In addition, any transaction is exempt from the statutory ban if it is proposed at a time when the corporation has proposed, and a majority of certain continuing directors of the corporation have approved, a transaction with a party who is not an interested stockholder of the corporation, or who becomes such with board approval, if the proposed transaction involves:

- certain mergers or consolidations involving the corporation;
- a sale or other transfer of over 50% of the aggregate assets of the corporation; or
- a tender or exchange offer for 50% of more of the outstanding voting stock of the corporation.

A corporation may, at its option, exclude itself from the coverage of Section 203 by amending its certificate of incorporation or bylaws by action of its stockholders to exempt itself from coverage, provided that such bylaw or charter amendment shall not become effective until 12 months after the date it is adopted. We have not adopted such a charter or bylaw amendment.

Board of Directors

Number of Directors. Our Bylaws provide that the number of directors shall be not less than three nor more than 15, the exact number to be fixed from time to time by our board of directors. Vacancies in the board of directors or newly created directorships resulting from an increase in the number of directors may be filled by a majority of the remaining directors (though less than a quorum), or by a sole remaining director. Accordingly, our board of directors could prevent any stockholder from obtaining majority representation on our board of directors by enlarging the size of the board of directors and filling the new directorships with the board of directors' own nominees.

Removal of Directors. Our Restated Certificate of Incorporation and Bylaws provide that a director may be removed only for cause. "Cause" is defined to exist only if the director has been (1) convicted of a felony, adjudicated to be liable for gross negligence, recklessness or misconduct in the performance of his or her duty to us in a manner of substantial importance to us, or adjudicated to be mentally incompetent, which mental incompetency directly affects his or her ability as one of our directors; and (2) such conviction or adjudication was made by a court of competent jurisdiction and is no longer subject to appeal.

Certain Voting Requirements in Our Restated Certificate and Bylaws

Amendment of Restated Certificate of Incorporation. The affirmative vote of the holders of at least 66 and 2/3% of the voting power of all our outstanding voting shares is required to alter, amend, adopt any provision inconsistent with, or repeal the provisions of our Restated Certificate of Incorporation relating to the election, removal and classification of directors and amendment of our Bylaws.

Amendments to Bylaws. Our Restated Certificate of Incorporation and Bylaws further provide that the board of directors has the power to make, alter, amend and repeal our Bylaws, except so far as bylaws adopted by our stockholders otherwise provide. Notwithstanding the foregoing, our Bylaws may not be altered, amended or repealed, and no provision inconsistent therewith may be adopted, by action of the stockholders without the affirmative vote of at least 66 and 2/3% of the voting power of all our outstanding shares.

Supermajority Vote for Certain Transactions. Under Delaware law, and subject to certain exceptions, unless a greater vote is required in the corporation's certificate of incorporation, a merger, consolidation or dissolution of a corporation may be approved by a majority vote of the outstanding stock of the corporation entitled to vote thereon. Our Restated Certificate of Incorporation contains provisions that require the approval of holders of at least 80% of the voting power of the then outstanding shares of our capital stock entitled to vote as a condition for any of the following actions:

- a merger or consolidation;
- a share exchange;
- the adoption of any plan or proposal for liquidation, dissolution or reorganization; and
- a sale, lease or other disposition of all or substantially all of our assets on a consolidated basis.

The 80% voting requirement is not applicable if such action is approved by a majority of our "continuing directors" prior to the transaction. The term "continuing director" is defined to mean:

- any member of our board of directors as of December 31, 1992;
- any new director who is proposed to be a director of ours by a majority of the continuing directors then on the board of directors; and
- any successor of a continuing director who is recommended to succeed a continuing director by a majority of the continuing directors then on the board of directors.

The affirmative vote of the holders of at least 80% of the voting power of all our outstanding voting shares is required to amend, repeal, or adopt any provisions inconsistent with, the provisions of our Restated Certificate of Incorporation described in this paragraph.

Advance Notice Procedure for Stockholder Proposals. Our Bylaws establish an advance notice procedure for the nomination of candidates for election as directors, as well as for stockholder proposals considered at annual meetings of stockholders. These procedures may operate to limit the ability of stockholders to bring business before a stockholders' meeting, including with respect to the nomination of directors or considering any transaction that could result in a change in control.

Transfer Agent and Registrar

The transfer agent and registrar for our common stock is Computershare Trust Company, N.A.

Exhibit 21.1

Subsidiary Name	**Place of Registration**
VAALCO Gabon (Etame), Inc.	Delaware
VAALCO Energy (EG), Inc.	Delaware
VAALCO Energy (International) LLC	Delaware
VAALCO Energy (Holdings), LLC	Delaware
VAALCO International Management, LLC	Delaware
VAALCO Energy (G), Inc.	Delaware
VAALCO Energy (H), Inc.	Delaware
VAALCO Energy CDI 2, Inc.	Delaware
VAALCO Energy Mauritius (EG), Ltd	Mauritius
VAALCO Gabon S.A.	Gabon
VAALCO Energy Canada, Inc.	Province of Alberta
VAALCO Egypt Holdings Inc.	Turks & Caicos
TG Holdings Yemen Inc.	Turks & Caicos
VAALCO West Bakr Inc.	Turks & Caicos
VAALCO West Gharib Inc.	Turks & Caicos
VAALCO NW Gharib Inc.	Turks & Caicos
VAALCO S Ghazalat Inc.	Turks & Caicos
VAALCO Gabon (G), Inc.	Turks & Caicos
VAALCO Gabon (H), Inc.	Turks & Caicos
VAALCO Energy Cote d'Ivoire (2), Inc.	Turks & Caicos
VAALCO Energy Cote d'Ivoire AB	Sweden
VAALCO Energy Cote d'Ivoire Holding AB	Sweden
SPE Nigeria AB	Sweden
VAALCO Energy Cote d'Ivoire SPE AB	Sweden
Svenska Nigeria Exploration & Production Ltd	Nigeria

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the registration statement (No. 333-284185) on Form S-3 and the registration statements (Nos. 333-279986, 333-257028, 333-239424, 333-218824 and 333-197180) on Form S-8 of our reports dated March 16, 2026, with respect to the consolidated financial statements of VAALCO Energy, Inc. and subsidiaries and the effectiveness of internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
March 16, 2026

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

The undersigned hereby consents to the references to our firm in the form and context in which they appear in the Annual Report on Form 10-K of VAALCO Energy, Inc. for the year ended December 31, 2025. We hereby further consent to the use of information contained in our reports setting forth the estimates of revenues from VAALCO Energy, Inc.'s oil and gas reserves as of December 31, 2025, 2024, and 2023, and to the inclusion of our reports dated February 26, 2026, February 27, 2026, and March 3, 2025, as exhibits to the Annual Report on Form 10-K of VAALCO Energy, Inc. for the year ended December 31, 2025. We further consent to the incorporation by reference thereof into VAALCO Energy, Inc.'s Registration Statements on Forms S-3 (Nos. 333-284185) and Forms S-8 (Nos. 333-279986, 333-257028, 333-239424, 333-218824, and 333-197180).

NETHERLAND, SEWELL & ASSOCIATES, INC.

/s/ Richard B. Talley, Jr.
By:
Richard B. Talley, Jr., P.E.
Chairman and Chief Executive Officer

Houston, Texas
March 16, 2026

Exhibit 31.1

**CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO
EXCHANGE ACT RULES 13a-14(a) AND 15d-14(a),
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

I, George W.M. Maxwell certify that:

(1) I have reviewed this annual report on Form 10-K of VAALCO Energy, Inc.;

(2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

(3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

(4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

(5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 16, 2026

/s/ George W.M. Maxwell

George W.M. Maxwell
Chief Executive Officer

Exhibit 31.2

**CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO
EXCHANGE ACT RULES 13a-14(a) AND 15d-14(a),
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

I, Ronald Bain, certify that:

(1) I have reviewed this Annual Report on Form 10-K of VAALCO Energy, Inc.;

(2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

(3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

(4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

(5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 16, 2026

/s/ Ronald Bain

Ronald Bain
Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of VAALCO Energy, Inc. (the “Company”) on Form 10-K for the year ended December 31, 2025, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, George W.M. Maxwell, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities and Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 16, 2026

/s/ George W.M. Maxwell

George W.M. Maxwell, Chief Executive Officer

EXHIBIT 32.2

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of VAALCO Energy, Inc. (the "Company") on Form 10-K for the year ended December 31, 2025, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Ronald Bain, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities and Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 16, 2026

/s/ Ronald Bain

Ronald Bain, Chief Financial Officer

Exhibit 99.1

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

CHAIRMAN & CEO
RICHARD B. TALLEY, JR.

PRESIDENT & COO
ERIC J. STEVENS

EXECUTIVE COMMITTEE
ROBERT C. BARG
P. SCOTT FROST
JOHN G. HATTNER
JOSEPH J. SPELLMAN

February 26, 2026

Mr. George Maxwell
VAALCO Energy Inc.
2500 CityWest Boulevard, Suite 400
Houston, Texas 77042

Dear Mr. Maxwell:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2025, to the VAALCO Energy Inc. (VAALCO) interest in certain oil properties located in the Petrobakr Merged Concession, Egypt. We completed our evaluation on January 29, 2026. It is our understanding that the proved reserves estimated in this report constitute approximately 20 percent of all proved reserves owned by VAALCO. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future United States income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for VAALCO's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the gross (100 percent) oil reserves and the net oil reserves and future net revenue to the VAALCO interest in these properties, as of December 31, 2025, to be:

	Oil Reserves (MBBL)		Future Net Revenue (M$)	
Category	Gross (100%)	Net	Total	Present Worth at 10%
Proved Developed Producing	10,057.4	5,928.8	118,367.1	104,149.5
Proved Developed Non-Producing	3,808.5	2,248.7	18,027.5	12,041.9
Proved Undeveloped	741.8	437.0	4,046.0	1,861.0
Total Proved (1P)	14,607.6	8,614.4	140,440.6	118,052.5

Totals may not add because of rounding.

The oil volumes shown include crude oil only. Oil volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Produced gas is flared or consumed in field operations. Monetary values shown in this report are expressed in United States dollars ($) or thousands of United States dollars (M$).

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

The contractors' share of production is calculated pursuant to the provisions of the production sharing contract for the Petrobakr Merged Concession. Included are determinations of cost oil incorporating the unrecovered cost pool and estimated cost-recoverable expenditures scheduled in the future; the portion of cost oil remaining after these expenditures have been recovered is referred to as excess cost oil. Also included are determinations of profit oil based on estimated future oil production rates.

Gross revenue is VAALCO's share of the gross (100 percent) revenue from the properties after deducting the Egyptian national government (the State) share of profit oil. Future net revenue is after deductions for these amounts and VAALCO's share of capital costs, abandonment costs, bonuses paid to the State, the State's share of excess cost oil, and operating expenses. The future net revenue is before consideration of any United States income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

The oil price used in this report is based on the 12-month unweighted arithmetic average of the first-day-of-the-month Platts Dated Brent spot price for each month in the period January through December 2025. The average price of $69.47 per barrel is adjusted for quality, transportation fees, and market differentials. The adjusted oil price of $57.66 per barrel is held constant throughout the lives of the properties.

Operating costs used in this report are based on operating expense records of VAALCO, the operator of the properties. As requested, operating costs are limited to direct concession- and field-level costs and VAALCO's estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Operating costs have been divided into concession-level costs, per-well costs, and per-unit-of-production costs and are not escalated for inflation.

Capital costs used in this report were provided by VAALCO and are based on authorizations for expenditure, internal planning budgets, and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, recurring maintenance projects, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Capital costs are not escalated for inflation. It is our understanding that VAALCO would not incur any costs due to abandonment, nor would it realize any salvage value for the lease and well equipment.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical concession-level accounting statements.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by VAALCO, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in

accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from VAALCO, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. John R. Cliver, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2009 and has over 5 years of prior industry experience. Zachary R. Long, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2007 and has over 2 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Chairman and Chief Executive Officer

By: John R. Cliver
John R. Cliver, P.E. 107216
Senior Vice President

Date Signed: February 26, 2026

STATE OF TEXAS
J. R. CLIVER
107216
LICENSED
PROFESSIONAL ENGINEER

By: Zach Long
Zachary R. Long, P.G. 11792
Vice President

Date Signed: February 26, 2026

STATE OF TEXAS
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GEOLOGY
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DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir.* Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

- (i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- (ii) Same environment of deposition;
- (iii) Similar geological structure; and
- (iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen.* Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate.* Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate.* The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves.* Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

- (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
- (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

> *Supplemental definitions from the 2018 Petroleum Resources Management System:*
>
> *Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.*
>
> *Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.*

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- (i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
- (ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project.* A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well.* A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible.* The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR).* Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs.* Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well.* An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well.* An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field.* An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, 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—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. *Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
b. *Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.
f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.

Exhibit 99.2

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

CHAIRMAN & CEO
RICHARD B. TALLEY, JR.

PRESIDENT & COO
ERIC J. STEVENS

EXECUTIVE COMMITTEE
ROBERT C. BARG
P. SCOTT FROST
JOHN G. HATTNER
JOSEPH J. SPELLMAN

February 27, 2026

Mr. George Maxwell
VAALCO Energy Inc.
2500 CityWest Boulevard, Suite 400
Houston, Texas 77042

Dear Mr. Maxwell:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2025, to the VAALCO Energy Inc. (VAALCO) interest in certain oil properties located in the Etame Marin Permit, offshore Gabon. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute approximately 23 percent of all proved reserves owned by VAALCO. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future United States income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for VAALCO's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the gross (100 percent) oil reserves and the net oil reserves and future net revenue to the VAALCO interest in these properties, as of December 31, 2025, to be:

	Oil Reserves (MBBL)		Future Net Revenue[1] (M$)	
Category	Gross (100%)	Net[2]	Total	Present Worth at 10%
Proved Developed Producing	9,985.6	5,002.1	6,230.6	13,096.8
Proved Developed Non-Producing	572.4	284.9	4,991.0	3,702.3
Proved Undeveloped	9,460.1	4,714.1	21,999.7	14,761.9
Total Proved (1P)	20,018.1	10,001.1	33,221.3	31,561.0

[1] Future net revenue is after deducting estimated abandonment costs.
[2] Net reserves are prior to deductions for "income tax barrels".

The oil volumes shown include crude oil and condensate. Oil volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Produced gas is flared or consumed in field operations. Monetary values shown in this report are expressed in United States dollars ($) or thousands of United States dollars (M$).

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

The contractors' share of production is calculated pursuant to the provisions of the production sharing contract for the Etame Marin Permit. Included are determinations of cost oil incorporating the unrecovered cost pool and estimated cost-recoverable expenditures scheduled in the future. Also included are determinations of profit oil based on estimated future oil production rates.

As requested, our estimates of net reserves are prior to deductions for the portion of the Gabonese national government (the State) share of the profit oil required for payment of VAALCO's Gabonese income taxes, referred to herein as "income tax barrels". These income tax barrels have been calculated as the State's share of profit oil multiplied by VAALCO's working interest, net of the State participation.

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Gross revenue is VAALCO's share of the gross (100 percent) revenue from the properties after deducting all production sharing revenue paid to the State. Future net revenue is after deductions for these amounts and VAALCO's share of capital costs, abandonment costs, operating expenses, and production taxes; the production taxes include bonuses and fees paid to the State for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and Provision pour Investissements Diversifiées (PID)/Provision pour Investissements en Hydrocarbures (PIH). The future net revenue also includes credits for VAALCO's share of the State reimbursement and is before consideration of any United States income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

The oil price used in this report is based on the 12-month unweighted arithmetic average of the first-day-of-the-month Platts Dated Brent spot price for each month in the period January through December 2025. The average price of $69.47 per barrel is adjusted for quality, transportation fees, and market differentials. The adjusted oil price of $66.60 per barrel is held constant throughout the lives of the properties.

Operating costs used in this report are based on operating expense records of VAALCO, the operator of the properties. As requested, operating costs are limited to direct permit- and field-level costs and VAALCO's estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Operating costs have been divided into permit-level costs, per-well costs, and per-unit-of-production costs and include the costs associated with recurring electric submersible pump replacements, diesel purchases during periods where gas production is insufficient to fuel operations, and future changes to certain contractual fees. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by VAALCO and are based on authorizations for expenditure and internal planning budgets. Capital costs are included as required for new development wells, recurring maintenance projects, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are VAALCO's estimates of the costs to abandon the wells, platforms, and production facilities; these estimates do not include any salvage value for the platform and well equipment. It is our understanding that VAALCO has established escrow accounts for abandonment liability and expects these accounts to be fully funded by December 31, 2038. We further understand that if the economic limit for the permit area is reached before this date, then all abandonment costs not yet prefunded will be spent by December 31 of the year after the economic limit date. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical permit-level accounting statements.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by VAALCO, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates,

prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for non-producing zones and undeveloped locations; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from VAALCO, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. John R. Cliver, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2009 and has over 5 years of prior industry experience. Zachary R. Long, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2007 and has over 2 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Chairman and Chief Executive Officer

By: John R. Cliver
John R. Cliver, P.E. 107216
Senior Vice President

Date Signed: February 27, 2026

STATE OF TEXAS J. R. CLIVER 107216 LICENSED PROFESSIONAL ENGINEER

JRC:WKE

By: Zach Long
Zachary R. Long, P.G. 11792
Vice President

Date Signed: February 27, 2026

STATE OF TEXAS Z. R. LONG GEOLOGY 11792 LICENSED PROFESSIONAL GEOSCIENTIST

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir.* Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen.* Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate.* Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate.* The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves.* Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2018 Petroleum Resources Management System:

Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project.* A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well.* A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible.* The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR).* Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs.* Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well.* An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well.* An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field.* An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, 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—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. *Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
b. *Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*

e. *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.

Exhibit 99.3

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

CHAIRMAN & CEO
RICHARD B. TALLEY, JR.

PRESIDENT & COO
ERIC J. STEVENS

EXECUTIVE COMMITTEE
ROBERT C. BARG
P. SCOTT FROST
JOHN G. HATTNER
JOSEPH J. SPELLMAN

March 3, 2026

Mr. George Maxwell
VAALCO Energy Inc.
2500 CityWest Boulevard, Suite 400
Houston, Texas 77042

Dear Mr. Maxwell:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2025, to the VAALCO Energy Inc. (VAALCO) interest in certain oil and gas properties located in Baobab Field, Block CI-40, offshore Côte d'Ivoire. We completed our evaluation on January 21, 2026. It is our understanding that the proved reserves estimated in this report constitute approximately 42 percent of all proved reserves owned by VAALCO. It is also our understanding that in 2025, the floating production, storage and offloading vessel (FPSO) that processes production from Baobab Field was taken offline for a major refurbishment; therefore, all reserves for this field, including those associated with wells that were producing prior to the shutdown, are categorized as undeveloped as of December 31, 2025. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for VAALCO's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the VAALCO interest in these properties, as of December 31, 2025, to be:

	Net Reserves		Future Net Revenue(1) (M$)	
Category	Oil (MBBL)	Gas(2) (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	0.0	0.0	-93,831.1	-91,258.7
Proved Undeveloped	17,011.4	6,953.9	475,530.4	323,883.4
Total Proved	17,011.4	6,953.9	381,699.2	232,624.7

Totals may not add because of rounding.

(1) Future net revenue is after deducting estimated abandonment costs.
(2) Gas reserves are inclusive of fuel gas volumes expected to be consumed in field operations; fuel gas volumes are approximately 82 percent of total proved gas reserves.

The oil volumes shown include crude oil only. Oil volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases. Monetary values shown in this report are expressed in United States dollars ($) or thousands of United States dollars (M$).

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

The contractors' share of production is calculated pursuant to the provisions of the production sharing contract for Block CI-40. Included are determinations of cost oil and gas incorporating the unrecovered cost pool and estimated cost-recoverable expenditures scheduled in the future. Also included are determinations of profit oil and gas based on estimated future oil and gas production rates.

Gross revenue is VAALCO's share of the gross (100 percent) revenue from the properties after deducting all production sharing revenue paid to the Côte d'Ivoire national government (the State). Future net revenue is after deductions for these amounts and VAALCO's share of capital costs, abandonment costs, and operating expenses but before consideration of any United States income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report either are the fixed contract gas price or are based on the 12-month unweighted arithmetic average of the first-day-of-the-month oil price for each month in the period January through December 2025. For oil volumes, the average Platts Dated Brent spot price of $69.47 per barrel is adjusted for quality, transportation fees, and market differentials. The fixed contract gas price of $2.600 per MMBTU is adjusted for energy content. The adjusted product prices of $68.95 per barrel of oil and $2.771 per MCF of gas are held constant throughout the lives of the properties.

Operating costs used in this report are based on operating expense records of VAALCO. These costs include the overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs and include the costs associated with natural gas fuel purchases during periods where gas production is insufficient to fuel operations and fees paid to the State for training funds and domestic market obligations. Since all properties are nonoperated, headquarters general and administrative overhead expenses are not included. It is our understanding that while the FPSO is being refurbished operating costs will be capitalized, with the exception of fees paid to the State for training funds and domestic market obligations. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by VAALCO and are based on authorizations for expenditure and internal planning budgets. Capital costs are included as required for refurbishment of the FPSO, new development wells, workovers, recurring maintenance projects, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are VAALCO's estimates of the costs to abandon the wells and production facilities, net of any salvage value. It is our understanding that the contractors will establish escrow accounts for abandonment liability five years prior to license expiration and expect these accounts to be fully funded by license expiration in April 2038. We further understand that if the economic limit for the permit area is reached before this date, then all abandonment costs not yet prefunded will be spent by April 30 of the year after the economic limit date. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the VAALCO interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on VAALCO receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field-level accounting statements.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current

development plans as provided to us by VAALCO, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from VAALCO, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. John R. Cliver, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2009 and has over 5 years of prior industry experience. Zachary R. Long, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2007 and has over 2 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Chairman and Chief Executive Officer

By:
John R. Cliver, P.E. 107216
Senior Vice President

Date Signed: March 3, 2026

STATE OF TEXAS
J. R. CLIVER
107216
LICENSED
PROFESSIONAL ENGINEER

RJW:WKE

By:
Zachary R. Long, P.G. 11792
Vice President

Date Signed: March 3, 2026

STATE OF TEXAS
Z. R. LONG
GEOLOGY
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DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir.* Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

- (i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- (ii) Same environment of deposition;
- (iii) Similar geological structure; and
- (iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen.* Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate.* Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate.* The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves.* Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

- (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
- (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2018 Petroleum Resources Management System:

Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- (i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
- (ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project.* A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well.* A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible.* The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR).* Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs.* Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well.* An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well.* An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field.* An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, 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—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. *Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
b. *Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.
f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.

NETHERLAND, SEWELL
& ASSOCIATES, INC.
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ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

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EXECUTIVE COMMITTEE
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P. SCOTT FROST
JOHN G. HATTNER
JOSEPH J. SPELLMAN

March 3, 2026

Mr. George Maxwell
VAALCO Energy Inc.
2500 CityWest Boulevard, Suite 400
Houston, Texas 77042

Dear Mr. Maxwell:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2025, to the VAALCO Energy Inc. (VAALCO) interest in certain oil and gas properties located in Alberta, Canada, referred to herein as the Harmattan Properties. We completed our evaluation on January 28, 2026. It is our understanding that the proved reserves estimated in this report constitute approximately 14 percent of all proved reserves owned by VAALCO. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for VAALCO's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the VAALCO interest in the Harmattan Properties, as of December 31, 2025, to be:

	Net Reserves			Future Net Revenue (USM$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	1,179.2	1,328.8	9,059.5	39,310.8	26,414.6
Proved Undeveloped	1,162.7	451.6	3,149.8	16,252.6	1,355.7
Total Proved (1P)	2,341.9	1,780.4	12,209.2	55,563.5	27,770.4

Totals may not add because of rounding.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases. Monetary values shown in this report are expressed in United States dollars (US$) or thousands of United States dollars (USM$).

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. As requested, probable and possible reserves that exist for these properties have not been included. Our study indicates that as of December 31, 2025, there are no proved developed non-producing reserves for these properties. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Working interest revenue is VAALCO's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for VAALCO's share of royalties, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2025. For oil volumes, the average Platts Dated Brent price of US$69.47 per barrel is adjusted for quality and market differentials. For NGL volumes, the average West Texas Intermediate spot price of US$66.01 per barrel is adjusted for quality and market differentials. For gas volumes, the average TCPL Alberta (AECO-C) price of US$1.639 per MMBTU is adjusted for energy content and market differentials. The adjusted product prices of US$61.61 per barrel of oil, US$23.11 per barrel of NGL, and US$1.068 per MCF of gas are held constant throughout the lives of the properties.

Operating costs used in this report are based on operating expense records of VAALCO. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs. Headquarters general and administrative overhead expenses of VAALCO are included to the extent that they are covered under joint operating agreements for the operated properties. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by VAALCO and are based on internal planning budgets and actual costs from recent activity. Capital costs are included as required for new development wells and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are VAALCO's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the VAALCO interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on VAALCO receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by VAALCO, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information

promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from VAALCO, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the contractual rights to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. John R. Cliver, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2009 and has over 5 years of prior industry experience. Zachary R. Long, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2007 and has over 2 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Chairman and Chief Executive Officer

By: John R. Cliver
John R. Cliver, P.E. 107216
Senior Vice President

STATE OF TEXAS
J. R. CLIVER
107216
LICENSED
PROFESSIONAL ENGINEER

Date Signed: March 3, 2026

HPD:WKE

By: Zach Long
Zachary R. Long, P.G. 11792
Vice President

STATE OF TEXAS
Z. R. LONG
GEOLOGY
11792
LICENSED
PROFESSIONAL GEOSCIENTIST

Date Signed: March 3, 2026

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir.* Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen.* Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate.* Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate.* The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves.* Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2018 Petroleum Resources Management System:

Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project.* A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well.* A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible.* The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR).* Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs.* Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well.* An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well.* An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field.* An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

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Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, 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—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

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Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)
b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.
b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.
c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.
d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

> e. *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
> f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

> *From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):*
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> *Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.*
>
> *Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:*
>
> - *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
> - *The company's historical record at completing development of comparable long-term projects;*
> - *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
> - *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
> - *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.