
VAALCO ENERGY, INC.


# Expanding Our Portfolio to Support Incremental Sustainable Shareholder Returns

**2022 Annual Report**

VAALCO ENERGY, INC.

## Who We Are

VAALCO Energy, Inc. is a Houston-based independent energy company principally engaged in the production, development and acquisition of crude oil properties in west and north Africa and Canada. The Company has been an established operator for many years in the Etame Marin block, located offshore Gabon, holding a 63.6% participating interest, which to date has produced over 130 million gross barrels of crude oil.

In late 2022, VAALCO added producing properties in Egypt and Canada as a result of its business combination with TransGlobe Energy Corporation. The Company also owns and operates an offshore license in Equatorial Guinea that has undeveloped discoveries and significant upside potential.

VAALCO has always focused on safe and environmentally responsible operations with a long track record of success producing oil resources in West Africa. The Company's vision is to sustainably grow shareholder value and shareholder returns by maximizing its reserves and production performance in all of its producing areas by leveraging extensive operational and technical expertise.

VAALCO Energy was founded in 1985 and its common stock trades on the New York Stock Exchange and London Stock Exchange under the symbol "EGY."

### Gabon (Offshore) - Etame Marin Permit

**58.8%**
WI (Operated)

Q4'22 Production
**7.1 MBOEPD** (WI)
**6.2 MBOEPD** (NRI)

**10.2 MMBOE**
Proved Reserves (NRI)

**46,300**
Acreage (gross)

### Canada (Onshore) - Harmattan

**100%**
WI (Operated)

Q4'22 Production
**2.3 MBOEPD** (WI)
**2.3 MBOEPD** (NRI)

**9.2 MMBOE**
Proved Reserves (NRI)

**75,400**
Acreage (gross)

### Egypt (Onshore) - Eastern Desert and South Ghazalat

**100%**
WI (Operated)

Q4'22 Production
**8.9 MBOEPD** (WI)
**10.2 MBOEPD** (NRI)

**8.6 MMBOE**
Proved Reserves (NRI)

**52,500**
Acreage (gross)

### Equatorial Guinea (Offshore) - Block P

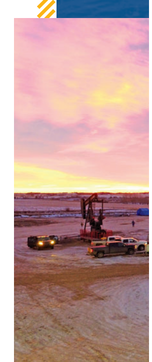
**45.9%**
WI (Operated)

Received approval of Venus standalone development plan, negotiating final documents for approval

**57,300**
Acreage (gross)

Gabon

Egypt



# 2022 PROGRESS ACHIEVED

## 2022 Accomplishments

In 2022, VAALCO made significant strides in building a diversified, multi-country exploration and production company focused on sustainable growth and returning value to shareholders. The transformational business combination with TransGlobe significantly increased the Company's production and reserves, further strengthened its balance sheet, and reduced portfolio risk. This transaction allowed VAALCO to meaningfully increase returns to shareholders by nearly doubling its dividend and instituting a $30 million share repurchase program.

Additionally, VAALCO made significant progress to move forward with the development of the discovered but undeveloped resources on its Block P concession in Equatorial Guinea that is expected to add a fourth producing area to VAALCO's portfolio in the next few years. Lastly, VAALCO accomplished a highly complex, full-field reconfiguration, maintenance turnaround and transition to a floating storage and offloading unit that will greatly reduce operating costs for years to come.

These accomplishments are a testament to the hard work, dedication and determination of VAALCO's workforce and partners.

Canada

Equatorial Guinea

# A letter from our Chief Executive Officer, George Maxwell

"Our most significant accomplishment in 2022 was the completion of an all-equity combination of two net cash, undervalued companies that provides us with additional size, scale, cash flow, and geographical diversity."

## To Our Fellow Shareholders

2022 was truly a transformational year for VAALCO and a highly positive one that saw us generate record financial results, successfully complete multiple high-impact operational projects, close a strategic acquisition that nearly doubled production, diversify our asset base and increase SEC proved reserves by nearly 150%. Additionally, we implemented our first-ever dividend program in 2022 paying out $9.4 million in dividends to shareholders and approved a $30 million stock buy-back program that has returned almost $9.0 million to shareholders through April 2023. Our commitment to returning value to our shareholders has been further enhanced in 2023, as we increased our quarterly dividend by 92%, from $0.0325 per share to $0.0625 per share. Our balance sheet remains bank debt-free, even after we fully funded approximately $160 million in capital investments (excluding acquisitions) in 2022 from cash flow and cash on hand. We believe this was the largest capital program in our Company's history, that included drilling multiple wells and completely reconfiguring our Etame field infrastructure, while adding a long-lasting Floating Storage and Offloading vessel "FSO" solution that lowered costs and extended the economic field life at Etame. We have a strong production base that can generate significant cash flow moving forward to fund our dividend, buybacks, capital programs and potentially additional acquisitions. We have positive momentum in 2023 both operationally and financially and we are building size and scale to sustainably grow VAALCO.

I have been CEO at VAALCO for two years now and in Q1 2021, we were producing about 5,000 net barrels a day, with a 2P CPR reserve estimate of 10.4 MMBO from a single producing asset. We had no debt with about $20 million in unrestricted cash and the stock was trading around $2.25 per share and oil prices were around $75 per barrel.. My primary objectives were to accretively grow production and value through organic drilling, acquisitions and unlocking the inherent value of our asset base. We are long-term stewards of VAALCO and are

"We implemented our first-ever dividend program in 2022 paying out $9.4 million in dividends to shareholders and approved a $30 million stock buy-back program."

building a sustainable business that will maximize value. We are in a risk-based business with a lot of variability, but with significant upside. We believe we have managed these risks very well, while delivering record results.

We have had tremendous success at Etame drilling and developing that vast resource over the past 20 years. Our overall 2021/2022 drilling campaign was a success as the initial two wells were highly successful and exceeded our predrill estimates. The program has materially increased production and extended the economic life of the Etame field, thereby fulfilling the primary objectives of this campaign. We forecast the total drilling program at Etame will achieve payback in 2023 and have strong overall economics at current strip pricing, demonstrating the strong cash flow profile generated from this quality asset.

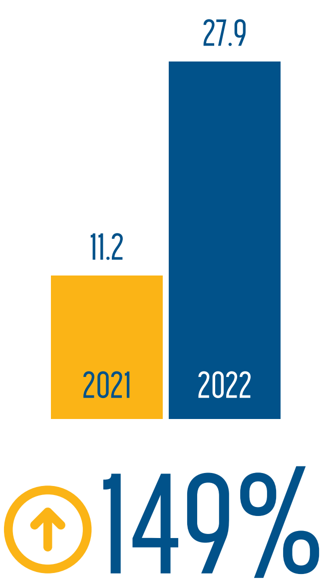
We successfully completed one of the most comprehensive and complex operational projects in nearly 20 years at Etame with the FSO conversion and full field reconfiguration. It is quite remarkable that a project of that scope and scale was successfully managed and executed by a company the size of VAALCO. Carrying out a project that at times concurrently involved expanding a platform deck, replacing the existing Floating Production, Storage and Offloading unit (FPSO) with an FSO, conducting drilling operations and completing an annual maintenance turnaround took quite a bit of planning. This project was an incredible feat from an engineering, logistical and operational standpoint. I would like to put this in perspective for you: we had about five times the number of personnel in the field during the project than we usually do, with additional boats, equipment and operational responsibilities, all working to ensure that we coordinated and completed this substantial project with minimal downtime to our production. We also had specialized equipment being manufactured, delivered and installed from all over the world, during a particularly difficult worldwide supply chain environment. The availability of equipment, consumables and global logistics have been strained over the past two years, which led to upward cost pressure and some delays. Remaining committed to safety and operational excellence, we took every opportunity to reduce project risk exposure. This effort increased our project costs modestly, but eliminated costly delays, ensured employee safety, mitigated the overall project risk and ensured minimum production interruptions during installation. The new FSO came online in Q4 2022 and provides us with additional flexibility as well as an effective capacity for storage that is approximately 50% larger than the previous FPSO. In addition, the new FSO has lower overall costs that is expected to lead to an extension of the economic field life, and result in a corresponding increase in recovery and reserves at Etame. Following this letter is a pictorial review and discussion of the installation and dedication of the FSO.

In early 2023, we held productive meetings in Houston with our partners and the Ministry of Mines and Hydrocarbons for Equatorial Guinea (EG) regarding the future of Block P. During these meetings, we finalized multiple substantive documents for Block P which includes the Venus

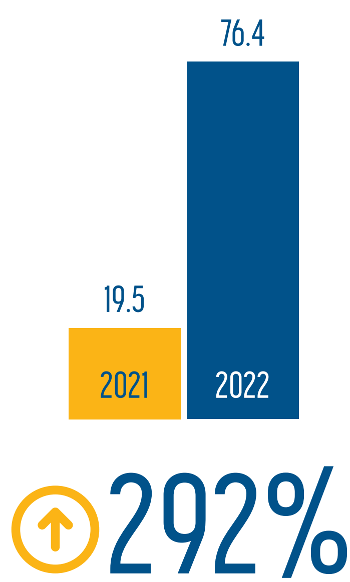
development, and we are working on concluding remaining documents to begin planning the development project in 2023. We are excited about our future plans for EG and we anticipate a strong, efficient and economic development of this discovery with first oil projected for 2026, which would add a fourth producing asset to our portfolio.

We believe our most significant accomplishment in 2022 was the completion of an all-equity combination of two net cash, undervalued companies, VAALCO and TransGlobe Energy Corporation, that provides us with additional size, scale, cash flow, and geographical diversity from adding new producing properties in Egypt and Canada, and creates a more de-risked portfolio. We have already captured meaningful synergies and expect our enhanced size and scale to yield additional cost synergies in the future. While the market has yet to afford us a higher multiple in our common stock price valuation, we believe the current significant discount to the valuation of our 2P reserves provides us a compelling reason for our stock buyback program. We now have a vast resource base of organic opportunities in four countries: Gabon, Egypt, Equatorial Guinea and Canada.

The impact of our highly successful 2022 activities can be seen in the substantial growth of our reserve base. SEC proved reserves at year-end 2022 increased 149% to 27.9 MMBOE. We added 18.6 MMBOE from the TransGlobe acquisition and 2.0 MMBOE from positive revisions which significantly boosted our SEC proved reserves. The proved reserve increase was partially offset by production of 3.9




Proved NRI Reserves[1] (MMBOE)




2P CPR WI Reserves[2] (MMBOE)

[1] SEC reserves are NSAI and GLJ estimates as of December 31, 2021 and December 31, 2022

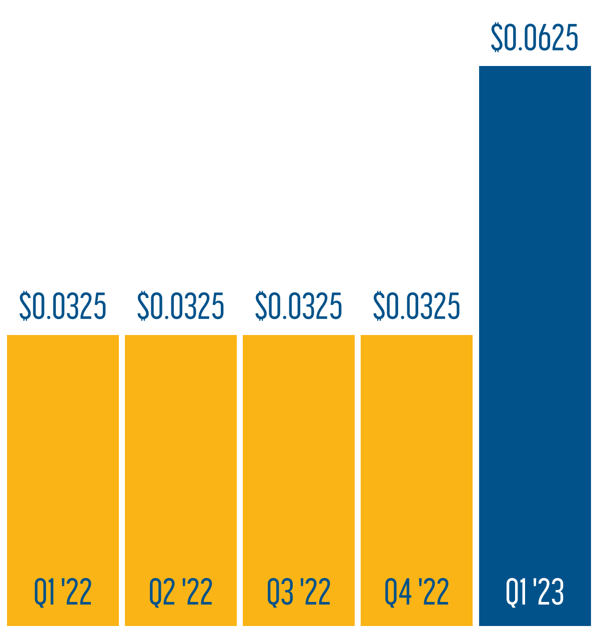
[2] 2P CPR Reserves are NSAI and GLJ estimates as of December 31, 2021 and December 31, 2022 (with Equatorial Guinea being estimated as of September 30, 2022) with VAALCO's management assumptions for escalated crude oil, natural gas and natural gas liquids prices and costs

MMBOE. This compelling increase in our SEC proved reserves does not include any positive impact from EG. We believe that once the final documents are executed, we will begin adding proved reserves as we proceed with the development plan. The standardized measure of our SEC proved reserves at year-end 2022 utilizing SEC pricing increased 529% from $99.3 million to $624 million. This was largely driven by the TransGlobe transaction and from higher SEC pricing. Our 2P CPR estimate, which includes proven and probable reserves using VAALCO's management assumptions for future Brent escalated crude oil pricing and costs reported on a working interest basis prior to deductions for government royalties, saw a year-over-year increase of 292% to 76.4 MMBOE. The 2P CPR NPV10 value increased more than four times from $183.7 million at year-end 2021 to $815 million at year-end 2022.

We have accomplished all of this while nearly doubling the share price, staying bank debt-free, and increasing the cash on the balance sheet to over $37 million at the end of 2022. We have done an excellent job growing VAALCO, prudently returning cash to shareholders and enhancing the value of the Company. We are forecasting 2023 net production to be more than three times where we were in Q1 2021, which should allow us to build significant cash. We are delivering on what we committed to the market and to our shareholders and we are better positioned today than we were two years ago when I began as CEO. We have improved average market trading liquidity almost seven-fold from early 2021. We also have the cash on hand and unused borrowing base to quickly execute accretive opportunities that become available.

As we look forward into 2023, we remain focused on the measured and methodical application of our strategy to sustainably grow the Company while delivering solid shareholder returns. I want to thank my management team and all of our employees for their continued hard work and dedication, as well as our Board for their guidance and support. We are confident that we can continue to deliver superior long-term value to our shareholders.

**George Maxwell**
*Chief Executive Officer*




## Returning Value Through Sustainable Dividends


# Successfully Completed the Highly Complex FSO Installation, Field Reconfiguration and Full Field Turnaround in October 2022

Increases Storage Capacity by 50% While Reducing Costs by about $13 to $16 Million Annually



Required Specialized Equipment That Was Being Manufactured, Delivered and Installed From All Over the World, During A Particularly Difficult Worldwide Supply Chain Environment

Remaining Committed to Safety And Operational Excellence, VAALCO Took Every Opportunity to Reduce Project Risk Exposure, Which Increased Project Costs, But Eliminated Costly Delays, Ensured Employee Safety and Ensured Minimal Production Interruptions

Lower Costs Extends the Economic Field Life at Etame, Increasing Reserves

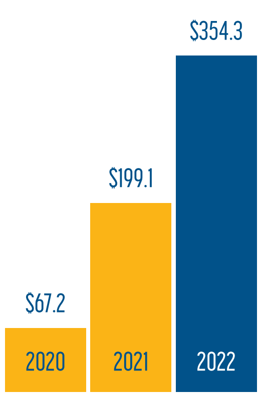



Better Positioned in Etame for the Next Decade

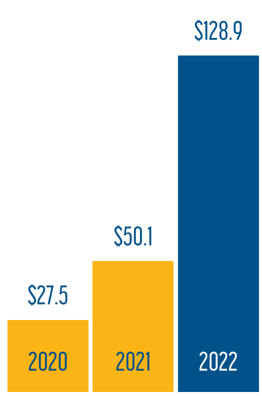
Reduces Emissions and Delivers ESG Benefits

# Financial Highlights

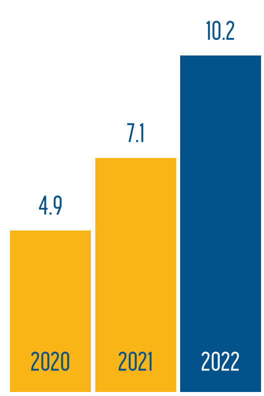
| *Year Ended December 31,* | 2022 | 2021 | 2020 |
|---|---|---|---|
| **Income Statement** (in thousands) | | | |
| Total Revenues | $ 354,326 | $ 199,075 | $ 67,176 |
| Operating Income (Loss) | $ 171,276 | $ 79,100 | $ (27,263) |
| Net Income (Loss) | $ 51,890 | $ 81,836 | $ (48,181) |
| **Cash Flow Statement** (in thousands) | | | |
| Operating Activities | $ 128,846 | $ 50,117 | $ 27,450 |
| Capex (oil and natural gas properties) | $ 159,897 | $ 39,063 | $ 24,328 |
| **Balance Sheet** (in thousands) | | | |
| Total Assets | $ 855,641 | $ 263,090 | $ 141,232 |
| Total Debt | — | — | — |
| **Operating Data** | | | |
| *Net Sales:* | | | |
| Oil, Natural Gas and Natural Gas Liquids (MBOE) | 3.68 | 2.71 | 1.63 |
| Average Daily Sales (MBOEPD) | 10.07 | 7.43 | 4.46 |
| *Averaged Realized Sales Price:* | | | |
| Oil, Natural Gas and Natural Gas Liquids ($/BOE) | $ 94.77 | $ 70.66 | $ 40.29 |
| *Net Production:* | | | |
| Average Daily Production (MBOEPD) | 10.21 | 7.12 | 4.85 |
| **Net SEC Proved Reserves** | | | |
| Oil, Natural Gas and Natural Gas Liquids (MMBOE) | 27.90 | 11.20 | 3.20 |
| Total Proved Developed (MMBOE) | 23.60 | 7.20 | 3.20 |
| Proved Undeveloped (MMBOE) | 4.30 | 4.00 | 0.00 |
| Proved Developed Reserves as a % of Proved Reserves | 85.0% | 64.0% | 100.0% |



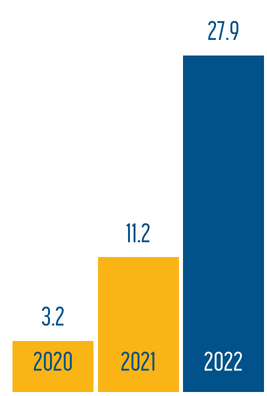

Revenues
(in millions)




Cash Provided by Operating Activities
(in millions)




Production Per Day
(in thousands of BOE)




Net SEC Proved Reserves
(in millions of BOE)

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

# FORM 10-K

**(Mark One)**

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
**For the fiscal year ended December 31, 2022**
**OR**

☐ **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.)** |

**9800 Richmond Avenue**
**Suite 700**
**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 ☐ No ☒
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15d of the Act. Yes ☐ No ☒
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 ☒ No ☐
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 ☒ No ☐
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 ☐ | Accelerated filer ☒ | Non-accelerated filer ☐ | Smaller reporting company ☒ |
| Emerging growth company ☐ | | | |

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. ☐
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 ☒
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. ☐
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). ☐
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒
As of June 30, 2022, the aggregate market value of the voting and non-voting common equity of the registrant held by non-affiliates was approximately $403.3 million based on a closing price of $6.94 on June 30, 2022.
As of March 31, 2023, there were outstanding 107,318,214 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 NGL Terms**

All references to $ are to United States dollars and references to C$ are to Canadian dollars.

**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.
- *MMBbl* — One million Bbls.
- *MMBoe* – One million Boes.
- *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**

- *Arta* — The Arta field in the West Gharib concession in the Egyptian Eastern Desert.
- *BWE Consortium* — A consortium of the Company, BW Energy and Panoro Energy provisionally awarded two blocks, G12-13 and 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.
- *Crown Royalty* — The payments to be made to the Province of Alberta pursuant to the Alberta Crown Agreement or under the generic crown royalty scheme.
- *EGPC* — Egyptian General Petroleum Corporation.
- *Egypt* — Arab Republic of Egypt.
- *Gabon* — Republic of Gabon.
- *Etame Consortium* — A consortium of four companies granted rights and obligations in the Etame Marin block offshore Gabon under the Etame PSC.

- *Merged Concession* — The modernized concession that merged the West Bakr, West Gharib and NW Gharib concessions.

- *Merged Concession Agreement* — The agreement with EGPC for the Merged Concession signed by the Ministry of Petroleum at an official signing ceremony on January 19, 2022.
- *PSC* — A production sharing contract.
- *FPSO* — A floating, production, storage and offloading vessel.
- *FSO* – A floating storage and offloading vessel.
- *NW Gharib* — The North West Gharib Concession area in Egypt.
- *NW Sitra* — The North West Sitra 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.
- *Royalty interest* — A real property interest entitling the owner to receive a specified portion of the gross proceeds of the sale of crude oil and, natural gas and NGLs production or, if the conveyance creating the interest provides, a specific portion of crude oil and, 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.
- *South Alamain* — The South Alamain Concession area in Egypt.
- *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 and, 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 and, 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.
- *Yusr* — The Yusr reservoirs in the West Bakr concession in the Egyptian Eastern Desert.

**Terms used to describe interests in wells and acreage**

- *Gross crude oil and, 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 and, 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 and, natural gas and NGLs reserves* — Developed crude oil and, 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 and, natural gas and NGLs reserves* — Proved crude oil and, natural gas and NGLs reserves are those quantities of crude oil and, 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 (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 crude oil (HKO) 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.

- *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.
- *Proved undeveloped crude oil and, natural gas reserve and NGLs reserves, PUDs* — Proved undeveloped crude oil and, 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.

- *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.

**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"), 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:

- 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;
- our ability to remediate our material weaknesses;
- 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, 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 NGL;
- difficulties encountered during the exploration for and production of crude oil, natural gas and NGL;

- 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 and, natural gas 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;
- the ultimate resolution of our negotiations with EGPC relating to the Effective Date Adjustment (as defined below);
- 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 and, natural gas and NGL;
- hedging decisions, including whether or not to enter into derivative financial instruments;
- general economic conditions, including any future economic downturn, the impact of inflation, disruption in financial of credit;
- our ability to enter into new customer contracts;
- changes in customer demand and producers' supply;
- actions by the governments of and events occurring in the countries in which we operate;
- actions by our joint venture owners;
- 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; and
- actions of operators of our crude oil and, 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 "Risk Factors" beginning on page 32 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.
- 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.
- We may not enter into definitive agreements with the BWE Consortium to explore and exploit new properties, and we may not be in a position to control the timing of development efforts, the associated costs or the rate of production of the reserves operated by the BWE Consortium or from any non-operated properties in which we have an interest.
- 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/decommissioning costs are too low, we could be required to expend greater amounts than expected.
- We may not generate sufficient cash to satisfy our payment obligations under the Merged Concession Agreement or be able to collect some or all of our receivables from the EGPC, which could negatively affect our operating results and financial condition.
- The Egyptian PSCs contain assignment provisions which, if triggered, could adversely affect our business.
- We could lose our interest in Block P if we do not meet our commitments under the production sharing contract.
- 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.
- Events outside of our control, such as the ongoing COVID-19 pandemic and Russia's invasion of Ukraine, 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 with respect to 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.
- There are inherent limitations in all control systems, and misstatements due to error or fraud that could seriously harm our business may occur and not be detected.
- We have identified material weaknesses in our internal control over financial reporting which has caused us to conclude our disclosure controls and procedures and our internal control over financial reporting were not effective as of December 31, 2022 and could, if not remediated, adversely affect our ability to report our financial condition and results of operations in a timely and accurate manner, investor confidence in our company and, as a result, the value of our common stock.
- We may not have enough insurance to cover all of the risks we face.
- Our business could suffer if we lose the services of, or fail to attract, key personnel.
- We may be exposed to the risk of earthquakes in Alberta, Canada.
- We may be adversely affected by changes in currency regulations.
- We may 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.
- There may be valid challenges to title or legislative changes which affect our title to the oil, natural gas and NGLs properties we control in Canada.
- 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, including but not limited to, earthquakes in Alberta and risks related to hydraulic fracking.
- An increased societal and governmental focus on ESG and climate change issues may adversely impact our business, impact 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 laws, environmental and other government regulations could be costly and could negatively impact production.
- A significant level of indebtedness incurred under the 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 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 Facility.
- If we experience in the future a continued period of low commodity prices, our ability to comply with applicable debt covenants may be impacted.
- The borrowing base under the Facility may be reduced pursuant to the terms of the 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.
- Restrictive debt covenants could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

# PART I

## Item 1. Business

### OVERVIEW

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.

We are a Houston, Texas-based independent energy company engaged in the acquisition, exploration, development and production of crude oil, natural gas and natural gas liquids ("NGLs").

Our primary source of revenue historically has been from the Etame PSC related to the Etame Marin block located offshore Gabon in West Africa. The Etame Marin block covers an area of approximately 46,200 gross acres located 20 miles offshore in water depths of approximately 250 feet. Currently, our working interest in the Etame Marin block is 58.8%, and we are designated as the operator on behalf of the Etame Consortium. 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% in June 2026 when the back-in carried interest increases to 10%.

We are also a member of a consortium with BW Energy and Panoro Energy (the “BWE Consortium”). The BWE Consortium has been provisionally awarded two blocks in the 12th Offshore Licensing Round in Gabon. The award is subject to concluding the terms of PSCs with the Gabonese government. BW Energy will be the operator with a 37.5% working interest, with VAALCO (37.5% working interest) and Panoro Energy (25% working interest) as non-operating joint owners. The two blocks, G12-13 and H12-13 are adjacent to our Etame PSC as well as BW Energy and Panoro’s Dussafu PSC offshore Southern Gabon and cover an area of 2,989 square kilometers and 1,929 square kilometers, respectively.

On October 13, 2022, VAALCO and VAALCO Energy Canada ULC (“AcquireCo”), our indirect wholly-owned subsidiary, completed the previously announced business combination involving TransGlobe Energy Corporation (“TransGlobe”), whereby AcquireCo acquired all of the issued and outstanding TransGlobe common shares pursuant to a plan of arrangement (the “Arrangement”) and TransGlobe became a direct wholly-owned subsidiary of AcquireCo and an indirect wholly-owned subsidiary of VAALCO in accordance with the terms of an arrangement agreement entered into by VAALCO, AcquireCo and TransGlobe on July 13, 2022 (the “Arrangement Agreement”). Prior to the Arrangement, TransGlobe was a cash flow-focused oil and gas exploration and development company whose activities were concentrated in Egypt and Canada. The post-Arrangement company (the “Combined Company”) is a leading African-focused operator with a strong production and reserve base and a diverse portfolio of assets in Gabon, Egypt, Equatorial Guinea and Canada. See Note 4 to the consolidated financial statements for further discussion regarding the Arrangement.

At December 31, 2022, net proved reserves related to Gabon were at 10.2 MBoe, net proved reserves related to Egypt were at 8.6 MBoe and net proved reserves related to Canada were at 9.2 MBoe.

We also currently own an interest in an undeveloped block offshore Equatorial Guinea, West Africa.

Recent developments are discussed below in "*Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.*"

### STRATEGY

We own crude oil, natural gas and NGLs producing properties and conduct operating activities in Egypt, Canada, and offshore Gabon, with a focus on maximizing the value of our current resources and expanding into new development opportunities across Africa. Our financial results are heavily dependent upon the margins between prices received for our crude oil, natural gas and NGLs production and the costs to find and produce such crude oil, natural gas and NGLs.

We intend to increase stockholder value by accretively growing production and value through organic drilling in a capital efficient manner to unlock the inherent value of our assets and making disciplined strategic 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 at Etame, Egypt, and Canada as well as future activity in Equatorial Guinea;
- 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 we have strong management and technical expertise specific to the markets in which we operate, and that our strengths include:

- Our reputation as a safe and efficient operator in Africa and Canada;
- Our history of establishing favorable operating relationships with host governments and local joint venture owners;
- Our subsurface knowledge of key plays and risks in the broader regional framework of discoveries and fields;
- Our operational capacity to take on new development projects;
- Our familiarity with local practices and infrastructure; and
- Our market intelligence to provide early insight into available opportunities.

## SEGMENT AND GEOGRAPHIC INFORMATION

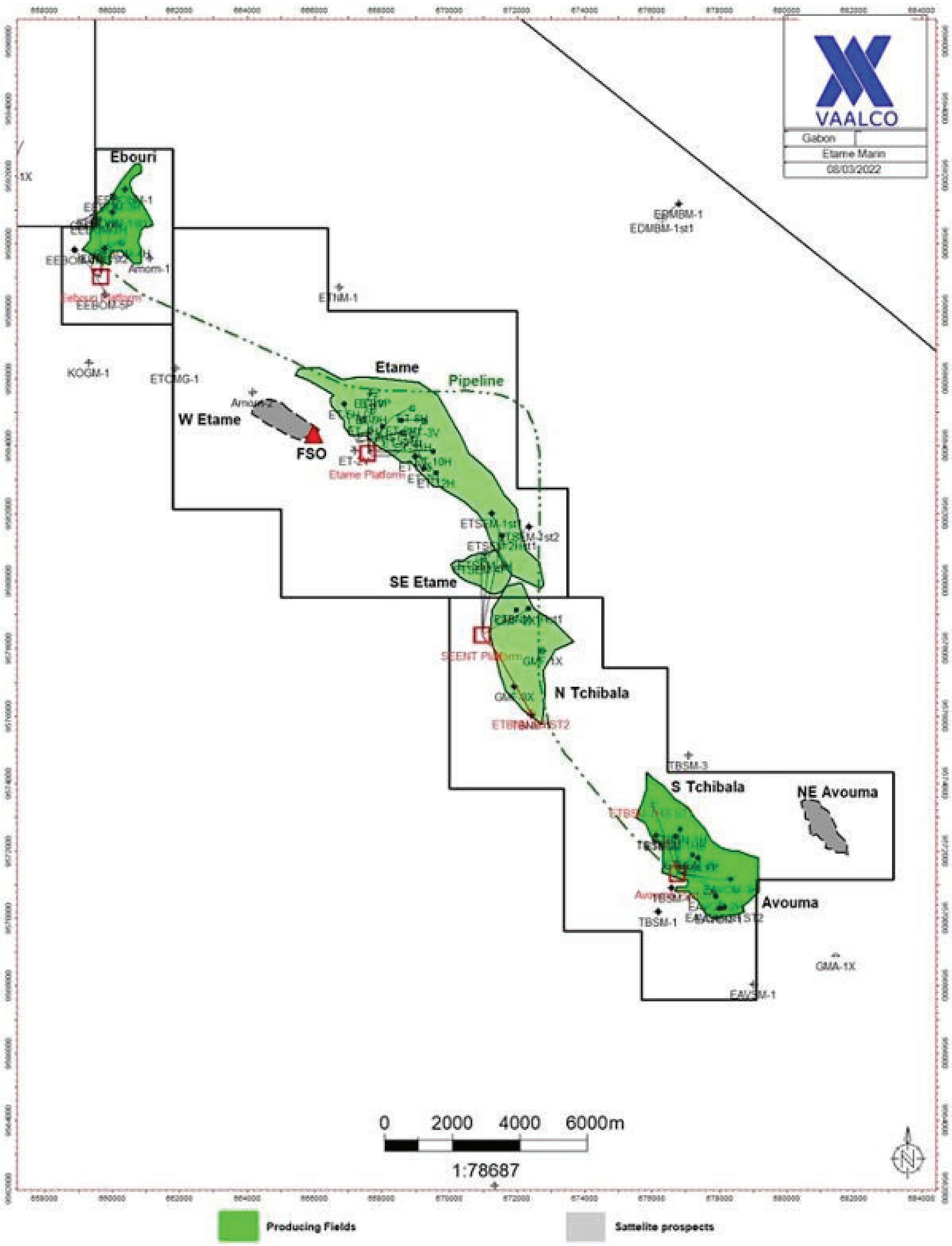
For operating segment and geographic financial information, see Note 5 to the Consolidated Financial Statements. Our reportable operating segments are Gabon, Egypt, Canada and Equatorial Guinea.

### *Gabon Segment*

*Offshore – Etame Marin Block*

The Etame PSC related to the Etame Marin block is located offshore Gabon. The Etame Marin block covers an area of approximately 46,200 gross acres located 20 miles offshore in water depths of approximately 250 feet. Currently, our working interest in the Etame Marin block is 58.8%, and we are designated as the operator on behalf of the Etame Consortium. 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% in June 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 with Gabon related to the Etame Marin block located offshore Gabon extends through 2028 with two five-year options to extend the PSC ("PSC Extension"). The PSC Extension provides us with the extended time horizon necessary to pursue developing the resources we have identified at Etame. Prior to February 1, 2018, the government of Gabon did not take any of its share of Profit Oil in-kind. Beginning February 1, 2018, the government of Gabon elected to, and has continued to, take its Profit Oil in-kind.

As of December 31, 2022, our core areas in Gabon are illustrated below:



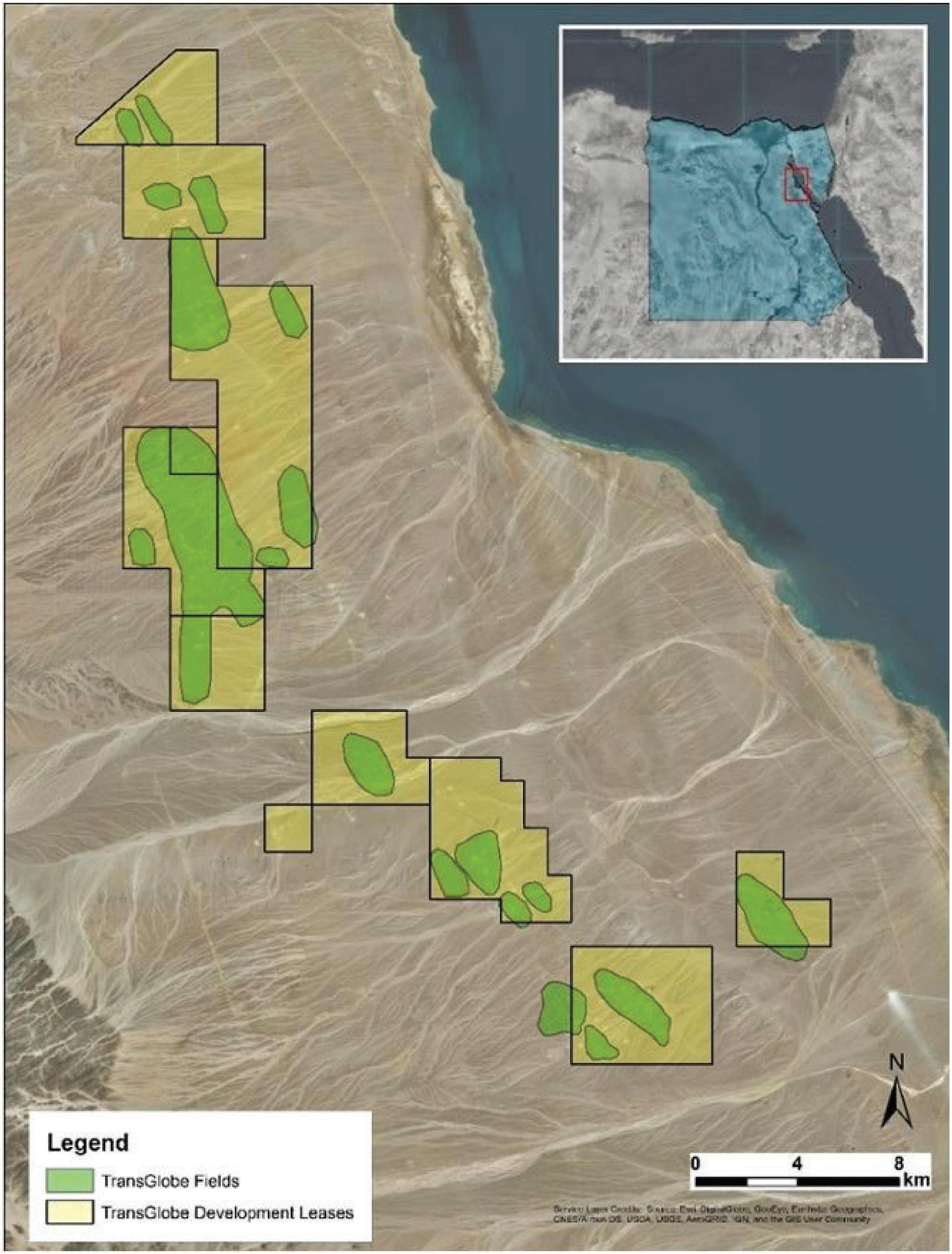
***Egypt Segment***

In Egypt, as of December 31, 2022, our interests are spread across two regions: the Eastern Desert, which contains the West Gharib, West Bakr and North West Gharib merged concessions, and the Western Desert, which contains the South Ghazalat concession. The Eastern Desert merged concession is approximately 45,067 acres and the Western Desert, South Ghazalat concession, is approximately 7,340 acres. Both of our Egyptian blocks are PSCs among the Egyptian General Petroleum Corporation ("EGPC"), the Egyptian government and us. We are the operator and have a 100% working interest in both PSCs. Our oil entitlement is the sum of cost oil, profit oil and excess cost oil, if any. The government takes their share of production based on the terms and conditions of the respective contracts. Our share of royalties is paid out of the government's share of production. Taxes are captured in the Egyptian government's net entitlement oil due and therefore there is no additional tax burden to us.

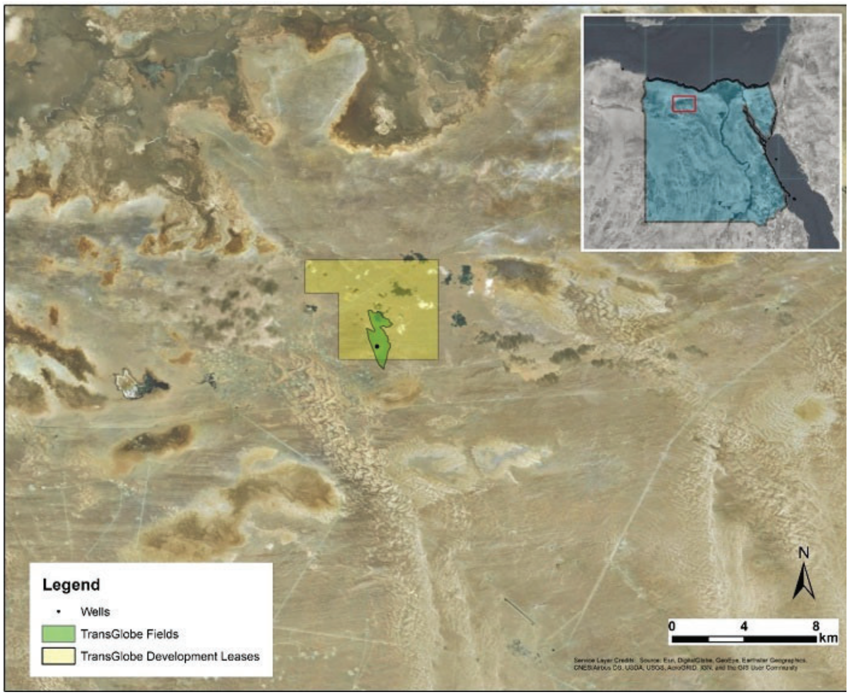
On January 20, 2022, prior to the consummation of the Arrangement, TransGlobe announced a fully executed Merged Concession Agreement with EGPC that merged the three existing Eastern Desert concessions with a 15-year primary term and improved economics. In advance of the Minister of Petroleum and Mineral Resources of the Arab Republic of Egypt (the "Minister") executing the Merged Concession Agreement, TransGlobe paid the first modernization payment of $15.0 million and signature bonus of $1.0 million as part of the conditions precedent to the official signing ceremony on January 19, 2022. On February 1, 2022, TransGlobe paid the second modernization payment of $10.0 million. In accordance with the Merged Concession, we agreed to substitute the 2023 payment and issue a $10.0 million credit against receivables owed from EGPC. We will make three further annual equalization payments of $10.0 million each beginning February 1, 2024, until February 1, 2026. We also have minimum financial work commitments of $50.0 million per each five-year period of the primary development term, commencing on February 1, 2020 (the "Merged Concession Effective Date"). As of December 31, 2022, the $50 million of financial work commitments had been delivered to EGPC. As the Merger Concession Agreement is effective as of February 1, 2020, there will be an effective date adjustment owed to us for the difference in the historic commercial terms and the revised commercial terms applied against the production since the Merged Concession Effective Date. The cumulative amount of the effective date adjustment was estimated at $67.5 million. However, the cumulative amount to be received as a result of the effective date adjustment is currently being finalized with EGPC and could result in a range of outcomes based on the final price per barrel negotiated. At December 31, 2022, we received $17.2 million of the receivable and the remaining $50.3 million is recorded on our consolidated balance sheet in Receivables-Other, net.

The Egyptian PSCs provide for the government to receive a percentage gross royalty on the gross production. The remaining oil production, after deducting the gross royalty, if any, is split between cost sharing oil and production sharing oil. Cost sharing oil is up to a maximum percentage as defined in the specific PSC. Cost oil is assigned to recover approved operating and capital costs spent on the specific project. Unutilized cost sharing oil or excess cost oil (maximum cost recovery less actual cost recovery) is shared between the government and the contractor as defined in the specific PSCs. Each PSC is treated individually in respect of cost recovery and production sharing purposes. The remaining production sharing oil (total production less cost oil) is shared between the government and the contractor as defined in the specific PSC. The Egyptian PSCs do not contain minimum production or sales requirements, and there are no restrictions with respect to pricing of the contractor's sales volumes. Except as otherwise disclosed, all crude oil sales are priced at current market rates at the time of sale.

The following illustrates our Merged Concession in the Eastern Desert:



The following illustrates our concession, South Ghazalat, in the Western Desert:



The following table summarizes our Egyptian PSC terms for the first tranche(s) of production for each block. The contracts have different terms for production levels above the first tranche, which are unique to each contract. The government's share of production increases and the contractor's share of production decreases as the production volumes go to the next production tranche. We are the contractor in all of our PSCs.

| **Block** | **Merged Concession** | **South Ghazalat** |
|---|---|---|
| Year acquired (1) | 2020 | 2013 |
| Block Area (acres) | 45,067 | 7,340 |
| Expiry date | 2035 | 2039 |
| Extensions | | |
| Exploration | N/A | N/A |
| Development | + 5 years | 20 + 5 years |
| Production Tranche (MBopd) | 0-25 | 0-5 |
| Maximum cost oil | 40% | 25% |
| Excess cost oil - Contractor | 15% | 5% |
| Depreciation per quarter | | |
| Operating | 100% | 100% |
| Capital | 6% | 5% |
| Production Sharing Oil: | | |
| Contractor | 30%* | 17% |
| Government | 70%* | 83% |

(1) - Represents the year acquired by TransGlobe, prior to the Arrangement.

*Merged Concession profit oil is set on a scale according to average Brent price and production:

| | **Crude oil produced (MBopd)** | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Brent Price ($/bbl) | Less than or equal to 5 MBopd | | More than 5 MBopd and less than or equal to 10 MBopd | | More than 10 MBopd and less than or equal to 15 MBopd | | More than 15 MBopd and less than or equal to 25 MBopd | | More than 25 MBopd | |
| | Government % | Contractor % | Government % | Contractor % | Government % | Contractor % | Government % | Contractor % | Government % | Contractor % |
| Less than or equal to $40/bbl | 67 | 33 | 68 | 32 | 69 | 31 | 70 | 30 | 71 | 29 |
| More than $40/bbl and less than or equal to $60/bbl | 68 | 32 | 69 | 31 | 70 | 30 | 71 | 29 | 72 | 28 |
| More than $60/bbl and less than or equal to $80/bbl | 70 | 30 | 71 | 29 | 72 | 28 | 74 | 26 | 76 | 24 |
| More than $80/bbl and less than or equal to $100/bbl | 72.5 | 27.5 | 73 | 27 | 74 | 26 | 76 | 24 | 78 | 22 |
| More than $100/bbl | 75 | 25 | 76 | 24 | 77 | 23 | 78 | 22 | 80 | 20 |

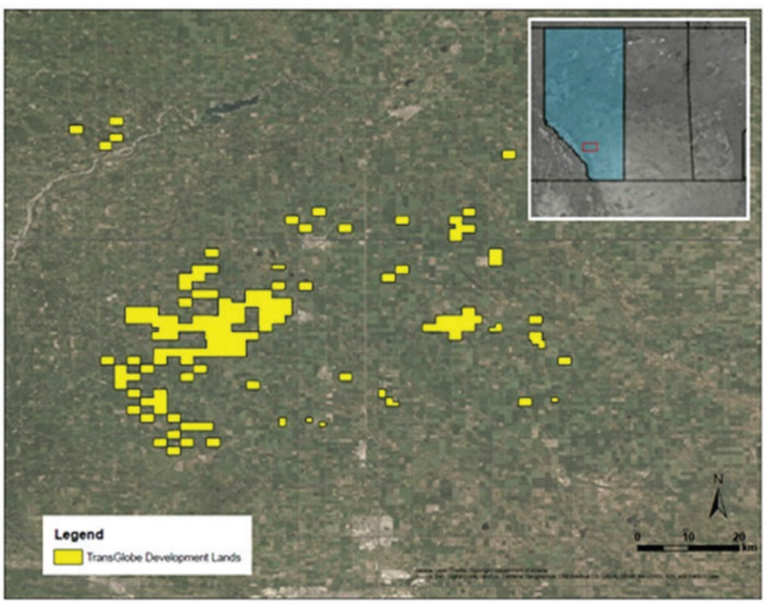
*Canada Segment*

In Harmattan, Canada, we now own production and working interests in certain facilities in the Cardium light oil and Mannville liquids-rich gas assets. Harmattan is located approximately 80 kilometers north of Calgary, Alberta. This property produces oil and associated natural gas from the Cardium and Viking zones and liquids-rich natural gas from zones in the Lower Mannville and Rock Creek formations at vertical depths of 1,200 to 2,600 meters. The Harmattan property covers 46,100 gross acres of developed land and 29,300 gross acres of undeveloped land. We also own a 100% working interest in a large oil battery and a compressor station where a majority of oil volumes are handled. All gas is delivered to a third party non-operated gas plant for processing.

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.

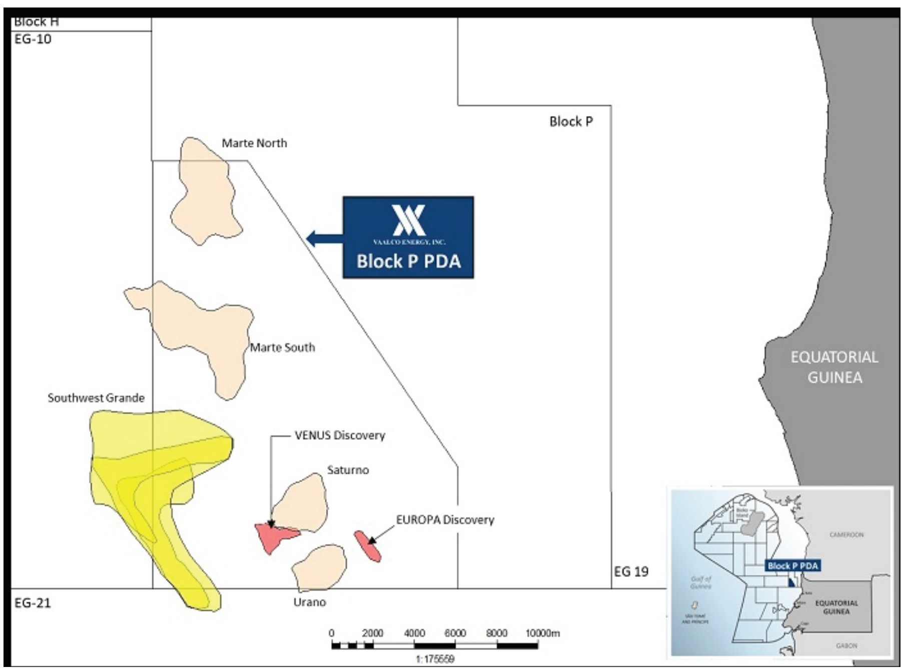
Below is an illustration of our Canadian assets:



***Equatorial Guinea Segment***

We acquired a 31% working interest in an undeveloped portion of a block ("Block P") offshore Equatorial Guinea in 2012. The Equatorial Guinea Ministry of Mines and Hydrocarbons ("EG MMH") approved our appointment as the operator of Block P on November 12, 2019. We acquired an additional working interest of 12% from Atlas Petroleum, thereby increasing our working interest to 43% in 2020, in exchange for a potential future payment of $3.1 million to Compania Nacional de Petroles de Guinea Equitoria, ("GEPetrol") in the event that there is commercial production from Block P. On August 27, 2020, the amendment to the production sharing contract to ratify our increased working interest and appointment as operator was approved by the EG MMH. In April 2021, Crown Energy, who held a 5% working interest, elected to default on its obligations from Block P. On April 12, 2021, the majority of non-defaulting parties assigned the defaulting party's interest to the non defaulting parties. As a result, our working interest increased to 45.9% with the approval of a fourth amendment to the production sharing contract by the EG MMH. On July 15, 2022, VAALCO, on behalf of itself and Guinea Ecuatorial de Petroleós ("GEPetrol"), submitted to the EG MMH a plan of development for the Venus development in Block P. On September 26, 2022, the EG MMH approved the submitted plan of development. Final documents to effect the plan of development are subject to EG MMH approval. The Block P production sharing contract provides for a development and production period of 25 years from the date of approval of a development and production plan for the area associated with the Venus development. The 2023 budget for the plan was delivered on October 12, 2022 to the MMH and was approved effective November 16, 2022.

In February of 2023, we acquired an additional 14.1% participating interest, increasing our participating interest in the Block to 60.0%. In March 2023, Atlas voted to participate in the Venus Development. Amendment 5 of the PSC was approved by all parties in March 2023, with this updated participating interest, and execution of the Venus development plan has been initiated. This increase of 14.1% participating interest increases our future payment to GEPetrol to $6.80 million at first commercial production of the Block. As of December 31, 2022, our Block P license in Equatorial Guinea is illustrated below:



As of December 31, 2022 and 2021, we had $10.0 million recorded for the book value of the undeveloped leasehold costs associated with the Block P license.

**DRILLING ACTIVITY**

In Gabon, we commenced the 2019/2020 drilling campaign in September 2019 and the 2021/2022 drilling campaign in December 2021. The following table sets forth the total number of completed exploratory and development wells in 2022, 2021 and 2020 on a gross and net basis:

| | Gabon | | | | | |
|---|---|---|---|---|---|---|
| | Gross | | | Net | | |
| | 2022 | 2021 | 2020 | 2022 | 2021 | 2020 |
| Exploratory wells | | | | | | |
| Productive | — | — | 1 | — | — | 0.3 |
| Dry | — | — | — | — | — | — |
| In progress | — | — | — | — | — | — |
| Development wells | | | | | | |
| Productive | **4** | — | 2 | **2.4** | — | 0.6 |
| Dry | — | — | — | — | — | — |
| In progress | **—** | 1 | — | **—** | 0.6 | — |
| Total wells | **4** | 1 | 3 | **2.4** | 0.6 | 0.9 |

In December 2021 we began drilling the ETAME 8H-ST development well that was completed in February 2022. In 2022 we completed the Etame 8H-ST, North Tchibala 2H-ST, South Tchibala-1HB-ST2 and Avouma 3H-ST development wells.

The following table sets forth the total number of exploratory and development wells from October 14, 2022 through December 31, 2022 in Canada and Egypt on a gross and net basis:

| | Canada | | Egypt | |
|---|---|---|---|---|
| | Gross | Net | Gross | Net |
| | 2022 | 2022 | 2022 | 2022 |
| Exploratory wells | | | | |
| Productive | — | — | — | — |
| Dry | — | — | **2** | **2** |
| In progress | — | — | — | — |
| Development wells | | | | |
| Productive | **3**(3) | **3** | **2**(1) | **2** |
| Dry | — | — | — | — |
| In progress | **—** | **—** | **1**(2) | **1** |
| Total wells | **3** | **3** | **5** | **5** |

(1) - Includes M-17 Development well which was spud on 28-Sept-22 and rig released on 17-Oct-22 and the NWG-2INJ-1A planned as injector well but encountered oil and came online 23-Dec-22
(2) - Includes the Arta-77Hz well in progress and coming online in the first quarter of 2023
(3) - Includes the 4-10-29-3W5 well, the 4-18-29-3W5 well and the 4-24-39-4W5 well

## ACREAGE AND PRODUCTIVE WELLS

Below is the total acreage under lease or covered by the Etame PSC, Egypt PSCs, Canada PSCs and Block P and the total number of productive crude oil, natural gas and NGLs wells as of December 31, 2022:

| | Developed | | Undeveloped | | Total | |
|---|---|---|---|---|---|---|
| **Acreage in thousands** | **Gross** | **Net** | **Gross** | **Net** | **Gross** | **Net** |
| Gabon | 6.9 | 4.1 | 39.4 | 23.1 | 46.3 | 27.2 |
| Canada | 46.1 | 41.6 | 29.3 | 24.8 | 75.4 | 66.4 |
| Egypt | 29.2 | 29.2 | 23.3 | 23.3 | 52.5 | 52.5 |
| Equatorial Guinea | — | — | 57.3 | 26.3 | 57.3 | 26.3 |
| Total acreage | 82.2 | 74.9 | 149.3 | 97.5 | 231.5 | 172.4 |

| **Productive crude oil wells** | **Gross** | **Net** |
|---|---|---|
| Gabon | 15 (1) | 8.8 |
| Canada | 63 | 59.5 |
| Egypt | 105 | 105.0 |
| Total Productive crude oil wells | 183 | 173.3 |

| **Productive natural gas wells** | **Gross** | **Net** |
|---|---|---|
| Gabon | — | — |
| Canada | 40 | 37.6 |
| Egypt | — | — |
| Total productive natural gas wells | 40 | 37.6 |

(1) - Excludes three wells shut-in due to the presence of high levels of $H_2S$.

## RESERVE INFORMATION

### *Estimated Reserves and Estimated Future Net Revenues*

### *Reserve Data*

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 2022, the average of such prices used for our reserve estimates was $100.35 per Bbl for crude oil from Gabon. Prices were between $84.76 and $85.65 per Bbl for crude oil from Egypt and $89.61 per Bbl for crude oil from Canada. For Gabon, this compares to the average of such price used for 2021 of $69.10 per Bbl and $42.46 per Bbl for 2020.

For 2022, the adjusted average price for our reserves associated with natural gas was $4.13 per MCF, $12.77 per Bbl for Ethane, $40.27 per Bbl for propane, $43.85 per Bbl for butane and $91.57 per Bbl for condensates.

Reserves reported below consist of net proved reserves related to the Etame Marin block located offshore Gabon in West Africa, the eastern desert and western area of Egypt and Harmattan area of west central Alberta, Canada. The tables below sets forth our estimated net proved reserve quantities for the years ended December 31, 2022, 2021 and 2020. The Gabon information was prepared by the independent petroleum engineering firm, Netherland, Sewell & Associates, Inc. ("NSAI"). The Egypt and Canada information was prepared by the independent firm, GLJ Ltd. ("GLJ"). The 2021 information includes the Sasol interest in the Etame Marin block as we acquired Sasol's interest on February 25, 2021.

| | As of December 31, 2022 | | | |
|---|---|---|---|---|
| | **Crude Oil (MBbls)** | **Natural Gas (MMcf)** | **NGLs (MBbls)** | **Total (MBoe)(1)** |
| Proved developed reserves | | | | |
| Gabon | **10,219** | — | — | **10,219** |
| Egypt | **8,001** | — | — | **8,001** |
| Canada | **1,722** | **11,023** | **1,855** | **5,414** |
| Total proved developed reserves | **19,942** | **11,023** | **1,855** | **23,634** |
| Proved undeveloped reserves | | | | |
| Gabon | — | — | — | — |
| Egypt | **576** | **—** | **—** | **576** |
| Canada | **1,885** | **5,516** | **942** | **3,747** |
| Total proved undeveloped reserves | **2,461** | **5,516** | **942** | **4,323** |
| Total proved reserves | **22,403** | **16,539** | **2,797** | **27,957** |

(1) To convert Natural Gas to MBoe, MMcf is divided by 6.

*Standardized Measure and Changes in Proved Reserves*

The following table shows changes in total proved Gabon reserves for all presented years:

| **Proved Reserves** | As of December 31, | | |
|---|---|---|---|
| ***(MBoe)*** | **2022** | **2021** | **2020** |
| Proved reserves, beginning of year | **11,218** | 3,216 | 4,966 |
| Production | **(2,971)** | (2,599) | (1,776) |
| Revisions of previous estimates | **1,972** | 7,968 | (471) |
| Extensions and discoveries | — | — | 497 |
| Purchase of reserves | — | 2,633 | — |
| Proved reserves, end of year | **10,219** | 11,218 | 3,216 |

In 2020, we completed the Southeast Etame 4H development whose reserves is included in extensions and discoveries in the December 2020 balance. In February 2021, we completed the acquisition of Sasol's interest in the Etame Marin block. The reserves associated with the acquisition is included in the purchase of reserves category of the December 2021 balance. In 2022, we drilled four wells that were previously included in the proved undeveloped category of the 2021 reserves.

In comparing the net proved reserves of 10.2 MMBbls at December 31, 2022 to the 11.2 MMBbls at December 31, 2021, we added 2.0 MMBbls of reserves through positive revisions of previous estimates. 1.3 MMBbls of the positive revisions were due to price and 0.7 MMBbls of positive revisions through performance. The increase of 45% in the average of the first-day-of-the-month prices for each of the year of the year, adjusted for quality, transportation fees and market differentials required by SEC rules to determine reserves, was $100.35 for this 2022 Annual Report up from $69.10 for the 2021 Annual Report.

The following table shows changes in total proved Egypt reserves for the period October 14, 2022 through December 31, 2022:

| **Proved Reserves** | As of December 31, | | |
|---|---|---|---|
| ***(MBoe)*** | **2022** | **2021** | **2020** |
| Proved reserves, beginning of year | — | — | — |
| Production | **(639)** | — | — |
| Revisions of previous estimates | — | — | — |
| Purchase of reserves | **9,216** | — | — |
| Proved reserves, end of year | **8,577** | — | — |

The following table shows changes in total proved Canada reserves for the period October 14, 2022 through December 31, 2022:

| **Proved Reserves** | **As of December 31,** | | |
|---|---|---|---|
| ***(MBoe)*** | **2022** | **2021** | **2020** |
| Proved reserves, beginning of year | — | — | — |
| Production | **(247)** | — | — |
| Revisions of previous estimates | — | — | — |
| Purchase of reserves | **9,408** | — | — |
| Proved reserves, end of year | **9,161** | — | — |

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

| | **As of December 31,** | | |
|---|---|---|---|
| | **2022** | **2021** | **2020** |
| | | ***(in thousands)*** | |
| Gabon | **$ 244,427** | $ 99,258 | $ 14,733 |
| Egypt | **226,888** | — | — |
| Canada | **153,150** | — | — |
| Standardized measure of discounted future net cash flows | **$ 624,465** | $ 99,258 | $ 14,733 |

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 are recoverable under the Etame PSC, and the reserves in place at the end of the contract remain the property of the Gabon government. Crude oil amounts shown for Egypt are recoverable under the Merged Concession and the western desert South Ghazalat concession, and the reserves in place at the end of those concessions remain the property of the Egyptian government. The reserves at the end of the contract 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 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 PUDs to ensure an appropriate plan for development exists.

For Gabon, in December 2021 we began drilling the ETAME 8-H development well that was completed in February 2022. In 2022 we drilled and completed the Etame 8H-ST, North Tchibala 2H-ST, South Tchibala-1HB-ST2 and Avouma 3H-ST development wells. These wells were considered PUDs in the December 2021 reserve report. We estimate the cost of the current 2021/2022 drilling program with the four wells and two additional workovers to be $180 million, or $114 million, net to VAALCO's participating interest. For 2022, we incurred approximately $148 million, or about $94 million net to VAALCO's participating interest. At December 31, 2022, we had no PUDs included in our year-end reserve report.

At December 31, 2022, as a result of the acquisition of TransGlobe, we had 31 PUD locations included in our reserves which we will complete within the next five years. Twenty-five of the PUD wells are in Canada and six are in Egypt.

***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 our Technical Reserve Committee and our reservoir engineer, who is our principal engineer. Our principal engineer has over 30 years of experience in the crude oil and natural gas industry, including over 10 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 a Master's degree in petroleum engineering and Texas Professional Engineering (PE) certification, 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 Reserve Committee of the Board of Directors meets periodically with management to discuss matters and policies related to reserves.

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 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 and Canada assets shown herein have been independently evaluated by NSAI (Gabon), GLJ (Egypt and Canada) and our Technical Reserve Committee.

**NET VOLUMES SOLD, PRICES, AND PRODUCTION COSTS**

Net volumes sold, average sales prices per unit, and production costs per unit for our 2022, 2021 and 2020 operations are shown in the tables below.

| | Sales Volumes (2) | | | Average Sales Price (2) | | | Average Production Cost (2) |
|---|---|---|---|---|---|---|---|
| | **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, 2022 | | | | | | | |
| Gabon | **2,919** | **—** | **—** | **$ 103.09** | **$ —** | **$ —** | **$ 33.18** |
| Egypt[1] | **547** | **—** | **—** | **69.00** | **—** | **—** | **21.84** |
| Canada[1] | **93** | **335** | **63** | **79.56** | **4.00** | **36.12** | **9.33** |
| Total | **3,559** | **335** | **63** | **$ 97.24** | **$ 4.00** | **$ 36.12** | **$ 30.12** |
| Year Ended December 31, 2021 | | | | | | | |
| Gabon | 2,711 | — | — | $ 70.66 | — | — | $ 29.97 |
| Year Ended December 31, 2020 | | | | | | | |
| Gabon | 1,627 | — | — | $ 40.29 | — | — | $ 22.93 |

(1) - Reflects sales and production costs after the acquisition date, October 13, 2022
(2) - The 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 9800 Richmond Avenue, Suite 700, 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 Nominating and Corporate 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., 9800 Richmond Avenue, Suite 700, Houston, Texas 77042. We intend to disclose updates 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 or amendment.

## CUSTOMERS

For the years ended December 31, 2022, 2021 and 2020, we sold our crude oil production from Gabon under a term contract with pricing in the month of lifting, adjusted for location and market factors. Our contract and three extension amendments with ExxonMobil Sales and Supply LLC ("ExxonMobil"), covered 100% of our crude oil sales from February 2020 through the end of July 2022 with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors. Revenues from sales of crude oil to Glencore were 100% of our Gabonese revenues from customers for the period of August 2022 through December 2022.

### *Egypt*

For the period of October 14, 2022 through December 31, 2022, EGPC covered 100% of our crude oil sales in Egypt.

### *Canada*

For the period of October 14, 2022 through December 31, 2022, revenues in Canada were concentrated in three separate customers that constituted approximately 54%, 32% and 14% of revenues in Canada.

## 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 the 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, 2022, we had 185 full-time employees, 90 of whom were located in Gabon, 30 in Egypt, 21 in Canada and 44 in Houston. Likewise, there are 56 contractors in Gabon, 6 contractors in Egypt, 5 contractors in Canada and 6 contractors in Houston. We are not subject to any collective bargaining agreements, although some of the national employees in Gabon are members of the NEOP (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 16% of our management team are female employees and 93.3% of our Gabon workforce is Gabonese.

*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, employee loans, 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. Our benefits 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 employs 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.

*COVID-19 Pandemic*

In response to the COVID-19 pandemic, related government legislation and guidelines and orders issued by key authorities, we implemented changes that we determined were in the best interest of our employees, as well as the communities in which we operate. These changes included quarantining and testing of employees and persons before going to our offshore platforms, having the majority of our employees work from home for several months, and implementing additional safety measures for employees continuing critical on-site work. We continue to maintain a high level of safety protocols and embrace a flexible working arrangement for our employees in all our locations.

## 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. Numerous governmental departments and agencies issue rules and regulations binding on the crude oil, natural gas and NGLs industry, some of which carry substantial penalties for the failure to comply. 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***

Our exploration and production activities offshore Gabon are subject to Gabonese regulations. 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. Moreover, these laws and regulations could change in ways that could substantially increase our costs or affect our operations. The following is a summary of certain applicable regulatory frameworks in Gabon.

*2014 Hydrocarbons Law* - Up until 2014, the fiscal and regulatory framework governing the exploration and production of hydrocarbons in Gabon was notably unregulated. Successive model contracts issued by the State of Gabon acted as guidelines; all fiscal aspects of each contract were negotiable between the State of Gabon and exploratory parties, including work commitments and exploration costs for each PSC.

In September 2014, Law No. 11/2014, of 28 August 2014, came into force in Gabon ("2014 Hydrocarbons Law"). The 2014 Hydrocarbons Law was not exhaustive; it sought to provide a framework of governing principles and rules, applicable to both the exploratory and extracting industry of hydrocarbons, as well as the downstream sector, to be complemented by implementing regulations.

Under the Gabonese Civil Code ("Civil Code"), laws will not have retroactive effects unless they expressly or tacitly provide otherwise. The Civil Code further provides that former laws continue to govern the effects of existing contracts, save in case of express or tacit derogation by the legislator and that, in any event, the application of a new law to existing contracts cannot modify the effects already produced by existing contracts under a former law, except via express derogation by the legislator.

The 2014 Hydrocarbons Law explicitly provided that establishment conventions, petroleum contracts, petroleum titles, mining concessions and exploitation permits concluded or granted by the State of Gabon prior to the date of its publication remained in force until their expiration date.

However, the 2014 Hydrocarbons Law further provided that unless such arrangements became consistent with the requirements of the 2014 Hydrocarbons Law, establishment conventions, mining concessions and exploitation permits in effect could not be extended or renewed. Furthermore, the 2014 Hydrocarbons Law prohibited establishment conventions and mining concessions, and provided that the exploitation of new discoveries in areas covered by existing conventions and concessions would be required to be made in accordance with the 2014 Hydrocarbons Law.

*2019 Hydrocarbons Law* - The 2014 Hydrocarbons Law was repealed in its entirety by Law No. 002/2019, of 16 July 2019, published on 22 July 2019 ("2019 Hydrocarbons Law"). As with the 2014 Hydrocarbons Law, the 2019 Hydrocarbons Law 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 are 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 Africa 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 since the implementation of the 2019 Hydrocarbons Law must include a clause providing that participation by the State of Gabon cannot exceed a 10% participating interest in the operations, to be carried by the contractor.

The 2019 Hydrocarbons Law also entitles the Gabon Oil Company to acquire a maximum 15% stake at market value in all PSCs as of the date of signature.

In addition, the 2019 Hydrocarbons Law 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.

***Canada***

In Harmattan, Canada, we now own production and working interests in certain facilities in the Cardium light oil and Mannville liquids-rich gas assets. Harmattan is located approximately 80 kilometers north of Calgary, Alberta. This property produces oil and associated natural gas from the Cardium and Viking zones and liquids-rich natural gas from zones in the Lower Mannville and Rock Creek formations at vertical depths of 1,200 to 2,600 meters. The Harmattan property covers 46,100 gross acres of developed land and 29,300 gross acres of undeveloped land. We also own a 100% working interest in a large oil battery and a compressor station where a majority of oil volumes are handled. All gas is delivered to a third party non-operated gas plant for processing.

Our exploration and production activities in Canada are subject to Canadian federal and provincial regulations. 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. Moreover, these laws and regulations could change in ways that could substantially increase our costs or affect our operations. The following is a summary of certain applicable regulatory frameworks in Canada.

With the exception of the province of Manitoba, each provincial government in Western Canada owns most of the mineral rights to the oil and natural gas located within their respective provincial borders. The Government of Alberta grants rights to explore for and produce oil and natural gas based on conditions set out in provincial legislation and regulations in exchange for a Crown Royalty share as set out in the Alberta Modernized Royalty Framework Guidelines, 2017 (as amended in 2023). To develop oil and gas resources, producers must also have access rights to the surface lands required to conduct operations. For private lands in Alberta, producers must either obtain consent of the private landowner or, where an agreement cannot be reached, a right of entry order issued under the Surface Rights Act (Alberta). In addition to obtaining mineral and surface rights in Canada, producers may need to engage extensively with Indigenous groups. Canadian federal and provincial governments have a constitutional duty to consult and, in some cases, accommodate Indigenous groups where a project might adversely impact a potential Indigenous rights and title claim. The procedural aspects of the duty to consult are often delegated to project proponents.

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 projects under federal government jurisdiction 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 Cabinet that a pipeline project is in the public interest may also be required under the Impact Assessment Act (Canada).

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. This may also include an environmental impact assessment under the Environmental Protection and Enhancement Act (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. For example, the AER administers the Licensee Liability Management Rating Program, which is currently being phased out with implementation of the AER’s new Liability Management Framework (“LMF”), to ensure adequate security is available for a project to be decommissioned safely, with no harm to the public or the environment.

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. One component of this regime is an emissions trading system for large industry. The GGPPA allows provinces to either 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”), which came into effect on January 1, 2020, regulates emissions of heavy industry in line with federal standards. On December 14, 2022, the Government of Alberta introduced several amendments to TIER which became effective January 1, 2023, broadening the scope of “large emitters” and strengthening facility specific benchmarks, among other things. The Government of Alberta also enacted the Methane Emission Reduction Regulation (Alberta) on January 1, 2020, which, in line with AER Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting (“AER Directive 060”) and AER Directive 017: Measurement Requirements for Oil and Gas Operations sets vent gas limits for methane per month, which are monitored through the collection of representative measuring data.

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. For example, in 2019 the Royalty Guarantee Act (Alberta) came into effect and provides that no major changes will be made to the current oil and gas royalty structure for a period of at least 10 years. AER Directive 060 was updated in April 2022 and sets more stringent vent gas limits for equipment installed after January 1, 2022, with a phased in approach for equipment installed prior to that date.

***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 agencies, including EGPC, the Egyptian Natural Gas Holding Company ("EGAS") and the Ganoube El-Wadi Petroleum Holding Company ("GANOPE") (each the "government entity") 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 GANOPE/EGAS/EGPC's 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.

***Equatorial Guinea***

Our exploration and production activities in Equatorial Guinea are subject to the applicable regulations of the country. 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. Moreover, these laws and regulations could change in ways that could substantially increase our costs or affect our operations. The following is a summary of certain applicable regulatory frameworks in 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.

Private crude oil companies have been allowed to conduct petroleum operations in Equatorial Guinea through PSCs signed by the minister responsible for petroleum operations on behalf of Equatorial Guinea. 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. In addition, the national oil company of Equatorial Guinea, GEPetrol, holds, manages and takes participations in petroleum activities on behalf of Equatorial Guinea.

In 2006, the Parliament of Equatorial Guinea passed a new hydrocarbons law ("2006 Hydrocarbons Law"), which superseded the previous 1981 Hydrocarbons Law, as amended in 2000, incorporating not only the regime applicable to the exploration, appraisal, development and production of hydrocarbons, but also 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 2006 Hydrocarbons Law grants the ministry appointed to be responsible for petroleum operations ("Appointed EG Petroleum Ministry") significantly broad regulatory, inspective and auditing powers concerning the performance of petroleum operations. These include the powers to negotiate, sign, amend and perform all contracts entered into between the State of Equatorial Guinea and independent contractors, as well as the right to access all data and information required for the control of contractors and their activities, including free access to the locations and facilities where petroleum operations are conducted.

In addition, the Appointed EG Petroleum Ministry can also order (i) the suspension of petroleum operations; (ii) the evacuation of persons from locations; (iii) the suspension of the use of any machine or equipment; and/or (iv) any other action it deems necessary or appropriate when the Appointed EG Petroleum Ministry determines that a given petroleum operation may cause injury to or death of persons, damage properties, or harm the environment, or whenever the national interest so requires.

Until June 2016, the Appointed EG Petroleum Ministry was the Ministry of Mines, Industry and Energy, whose organization and authority were granted under Decree No. 170/2005, of 15 August 2005.

In June 2016, the President of Equatorial Guinea appointed the EG MMH and the Minister of Industry and Energy, effectively splitting the Ministry of Mines, Industry and Energy into two ministries. However, no legislation on the organization and authority of each ministry has been enacted, and, in effect, the EG MMH has been exercising the powers contained within the Hydrocarbons Law to the Appointed EG Petroleum Ministry.

All contracts signed with the State of Equatorial Guinea for the exploration and production of hydrocarbons have taken the form of PSCs. A model PSC, approved along with the Hydrocarbons Law, must be used as the basis for any negotiation between independent contractors and the State of Equatorial Guinea. Over time, however, revised copies of the model PSC, reflecting changes made during negotiations of certain PSCs, have been used for the negotiation of subsequent PSCs.

The Hydrocarbons Law and Petroleum Regulations provide the Appointed EG Petroleum Ministry with the power to award contracts for the exploration and production of hydrocarbons and decide whether the award is made by means of competitive international public tender or direct negotiation. These contracts, however, which are to be negotiated by the Appointed EG Petroleum Ministry, shall only become effective after they have been ratified by the President of Equatorial Guinea and on the date of delivery to the contractor of a written notice of the President's ratification. In practice, however, this notification to operators has been provided by the Appointed EG Petroleum Ministry.

GEPetrol, established in 2001, is the national oil company of Equatorial Guinea and Sociedad Nacional de Gas de Guinea Equatorial ("Sonagas"), established in 2005, is the national gas company of Equatorial Guinea.

The Hydrocarbons Law provides that these national companies are exclusively owned by the State of Equatorial Guinea and must be supervised by the Appointed EG Petroleum Ministry.

Under the applicable laws, the State of Equatorial Guinea may elect to have, either directly or through a national company, a minimum interest of 20% in a PSC.

The State of Equatorial Guinea's interest (through GEPetrol or otherwise) may be, and typically is, carried. No costs are paid by the State of Equatorial Guinea or GEPetrol with respect to a carried interest. The Hydrocarbons Law provides that the State of Equatorial Guinea (through GEPetrol or otherwise) will only be required to contribute to any cost for petroleum operations that it has a carried interest in from the period where it notifies the contractor that it no longer wants its interest carried. In effect, however, the carry normally ends with the approval of the development and production of the asset subject to the PSC.

The terms and effects of the carry of an interest of the State of Equatorial Guinea (through GEPetrol or otherwise) are not clearly established in the Hydrocarbons Law or the Petroleum Regulations; the contractor that carries the State of Equatorial Guinea's interest is given the right to a percentage of the cost recovery oil pertaining to that interest, as agreed in each PSC.

## ENVIRONMENTAL REGULATIONS

### *General*

Our operations are subject to various federal, state, local and international laws and regulations, including laws and regulations in Gabon, Equatorial Guinea, Egypt and Canada, 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 with and are in good standing 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 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 and to the lobbying effects of various climate change non-governmental organizations. Legislation and increased regulation 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, in April 2016, 195 nations, including Gabon, Equatorial Guinea, Egypt, Canada and the U.S., 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 October 5, 2016, Canada ratified the Paris Agreement by a vote in Parliament. In August 2017, the U.S. Department of State officially informed the United Nations of the U.S.' intent to withdraw from the Paris Agreement, with such withdrawal becoming effective in November 2020. However, on January 20, 2021, President Biden issued written notification to the United Nations of the U.S.' intention to rejoin the Paris Agreement, which took effect on February 19, 2021, and on April 22, 2021, President Biden 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.

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, regulations or other requirements, will affect our financial condition and operating performance. In addition, 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 or impact the marketability of crude oil, natural gas and NGLs. 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 and storm patterns and 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 developing countries, it is unclear how quickly and to what extent Gabon, Equatorial Guinea or Egypt will increase their regulation of environmental 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 13 September 2021 on Climate Change, which ratification law has been recently published in the Official Gazette, with the objective of complying with the Paris Agreement. 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 compliance with such measures.

Any significant increase in the regulation or enforcement of environmental issues by Gabon, Equatorial Guinea or Egypt could have a material effect on us. 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 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, the EG MMH approved our appointment as technical operator in August 2020 and, since we were appointed, we will rely on the timely payment of cash calls by our joint venture owners to pay for 46.3% (including the 20% carry of GEPetrol's costs) of the Equatorial Guinea budget. 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 our $50 million Facility Agreement (the commitments under which decreases to $43.75 million beginning October 1, 2023). 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.

***We may not enter into definitive agreements with the BWE Consortium to explore and exploit new properties, and we may not be in a position to control the timing of development efforts, the associated costs or the rate of production of the reserves operated by the BWE Consortium or from any non-operated properties in which we have an interest.***

On October 11, 2021 we announced our entry into a consortium with the "BWE Consortium" and that the BWE Consortium had been provisionally awarded two blocks, G12-13 and H12-13, in the 12th Offshore Licensing Round in Gabon. The award is subject to concluding the terms of the production sharing contracts with the Gabonese government. BW Energy will be the operator with a 37.5% working interest and we and Panoro Energy will have a 37.5% working interest and 25% working interest, respectively, as non-operating joint owners. The joint owners in the BWE Consortium 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. Our obligations within the BWE Consortium are subject to a number of conditions, including the negotiation and execution of production sharing contracts with the Gabonese government, as well the entry into joint operating agreements with our joint interest owners. There is no assurance that we will be able to agree to terms on definitive production sharing contracts with the Gabonese government nor joint operating agreements with the joint owners in the BWE Consortium. If we are unable to negotiate and enter into definitive agreements with each party, we may not be able to explore, develop and exploit new properties, and our results of operations could be materially adversely affected.

We may have limited control over matters relating to development and exploitation activities, including the timing of and capital expenditures for such activities, in projects where we are not the operator, including properties operated by the BWE Consortium. 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 other 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.

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

***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. For example, the production of hydrogen sulfide at certain of our Etame Marin block wells creates unexpected production losses and delays in our development plans; see "*Item 1. Business – Segment and Geographic Information – Gabon Segment – Hydrogen Sulfide Impact*." 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, 2022, 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 2022, 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, and natural gas and NGLs that we will ultimately receive under these arrangements will differ based on numerous factors, including the price of crude oil, and 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/ decommissioning costs are too low, we could be required to expend greater amounts than expected.***

All of our existing properties in Gabon which have future abandonment obligations are located offshore. Our existing properties in Egypt and Canada are onshore. The costs to abandon offshore on onshore wells and the related infrastructure may be substantial. For financial accounting purposes, we record the fair value of a liability for an asset retirement obligation in the period that it is incurred and capitalize the related costs as part of the carrying amount of the long-lived assets. The estimated liability is reflected in the "Asset retirement obligations" and the "Accrued liabilities and other" line items of our consolidated balance sheet.

As part of the Etame Marin block production license, we are subject to an agreed-upon cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin block. Based upon the most recent abandonment study completed in November 2021, the abandonment cost estimate used for this purpose is approximately $81.3 million ($47.8 million net to our 58.8% working interest) on an undiscounted basis. On an annual basis over the remaining life of the production license, we must fund a portion of these estimated abandonment costs. See "*Item 1. Business – Segment and Geographic Information – Gabon Segment – Abandonment Costs*" for further information. Future changes to the anticipated abandonment cost estimates could change our asset retirement obligations and increase the amount of future abandonment funding payments we are obligated to make.

In Egypt, under model concession agreements and the Egyptian Fuel Materials Law No. 66/1953 as amended and its Executive Regulations issued by Minister of Industry Decree No. 758/1972 as amended (the "Fuel Materials Law"), liabilities in respect of decommissioning movable and immovable assets (other than wells) passes to the Egyptian Government through the transfer of ownership from the contractor to the government under the cost recovery process. The model concession agreements do not deal with area handover and abandonment upon termination, expiration or withdrawal from a concession agreement and certain articles in the Fuel Materials Law may apply, albeit the matter in practice is within the discretion of the EGPC. While the current risk that we may become liable for decommissioning liabilities in Egypt is low, future changes to legislation or practice of the EGPC could result in decommissioning, abandonment and/or handover liabilities in Egypt. Any increase in Egyptian decommissioning liabilities could adversely affect our financial condition.

In relation to petroleum wells, the contractor is responsible for decommissioning non-producing wells under a decommissioning plan approved by EGPC. If EGPC agrees that a producing well is not economic, then the contractor will be responsible for decommissioning the well under an EGPC-approved decommissioning plan. EGPC, at its own discretion, may not require a well to be decommissioned if it wants to preserve the ability to use the well for other purposes. As EGPC has discretion on decommissioning wells, there is a risk that we could incur well decommissioning costs. In accordance with the respective concession agreements, expenses approved by EGPC are recoverable through the cost recovery mechanism.

In Canada, liabilities in respect of the decommissioning of our wells, fields and related infrastructure are derived from legislative and regulatory requirements concerning the decommissioning of wells and production facilities and require us to make provisions for and/or underwrite the liabilities relating to such decommissioning. It is difficult to accurately forecast the costs that we would incur in satisfying any decommissioning obligations. When such decommissioning liabilities crystallize, we will be liable either on our own or jointly and severally liable with any other former or current partners in the field. In the event that we are jointly and severally liable with other partners and such partners default on their obligations, we would remain liable, and our decommissioning liabilities could be magnified significantly through such default. Any significant increase in the actual or estimated decommissioning costs that we incur may adversely affect our financial condition. Under the Alberta LMF, the AER began to set annual mandatory closure spend targets for all licensees with inactive inventory in 2022. Under the AER's Closure Nomination Program, introduced in February 2023 through an update to AER Directive 088: Licensee Life-Cycle Management, eligible landowners or land rights holders can nominate oil and gas wells and facilities that have been inactive or abandoned for longer than five years, for closure, at the expense of the licensee. Liability management in the Alberta oil and gas sector will continue to evolve as the AER continues its phased implementation of the new LMF.

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

***We may not generate sufficient cash to satisfy our payment obligations under the Merged Concession Agreement or be able to collect some or all of our receivables from the EGPC, which could negatively affect our operating results and financial condition.***

On January 19, 2022, subsidiaries of TransGlobe executed the Merged Concession Agreement with the EGPC, which is effective upon the Merged Concession Effective Date. As part of the conditions precedent to the signing of the Merged Concession Agreement by the Minister of Petroleum & Mineral Resources on behalf of the Egyptian Government, TransGlobe remitted the initial modernization payment of $15 million and signature bonus of $1 million. In accordance with the Merged Concession Agreement, TransGlobe made a modernization payment to the EGPC in the amount of $10 million on February 1, 2022. In accordance with the Merged Concession Agreement, we agreed to substitute the 2023 payment and issue a $10.0 million credit against receivables owed from EGPC. The modernization payments under the Merged Concession Agreement total $65 million and are payable over six years from the Merged Concession Effective Date. Under the Merged Concession Agreement, TransGlobe will be required to pay an additional $10 million on February 1st for each of the next three years. In addition, TransGlobe has committed to spending a minimum of $50 million over each five-year period for the 15 years of the primary term (total $150 million). Our ability to make scheduled payments arising from the Merged Concession Agreement will depend on our financial condition and operating performance, which would be subject to then prevailing economic, industry and competitive conditions and to certain financial, business, legislative, regulatory and other factors beyond our control. We may be unable to maintain a level of cash flow sufficient to permit us to satisfy the payment obligations under the Merged Concession Agreement. If we are unable to satisfy our obligations, it is possible that the EGPC could seek to terminate the Merged Concession Agreement, which would negatively affect our operating results and financial condition.

In addition, as of the Merged Concession Effective Date, there was an adjustment of funds owed to us for the difference between historic and Merged Concession Agreement commercial terms applied against Eastern Desert production from the Merged Concession Effective Date. The cumulative amount of the effective date adjustment was estimated at $67.5 million. However, the cumulative amount of the effective date adjustment is currently being finalized with EGPC and could result in a range of outcomes based on the final price per barrel negotiated. At December 31, 2022, we received $17.2 million of the receivable and the remaining $50.3 million is recorded on our consolidated balance sheet in Receivables-Other, net. If the EGPC's financial position becomes impaired or it disputes or if the EGPC refuses to pay some or all of the said amount, our ability to fully collect such receivable from the EGPC could be impaired, which could negatively affect our operating results and financial condition.

***The Egyptian PSCs contain assignment provisions which, if triggered, could adversely affect our business.***

On October 13, 2022, VAALCO completed its business combination transaction with TransGlobe whereby TransGlobe became an indirect wholly-owned subsidiary of VAALCO. Legacy subsidiaries of TransGlobe are party to the Egyptian PSCs, which contain restrictive wording relating to assignments of rights under such agreements which, if triggered, require consent of the Egyptian Government in connection with any such assignment (the "Assignment Provisions"). If triggered, the Assignment Provisions also provide that (i) in certain circumstances, the EGPC has the right to acquire the interest intended to be assigned; and (ii) an assignment fee is payable to the EGPC in an amount equal to 10% of the value of each assignment.

We do not believe the Arrangement triggered the Assignment Provisions. We have engaged and are continuing to engage, in discussions with the office of the Minister of Petroleum and Mineral Resources and the EGPC, for the purpose of clarifying that the Arrangement did not trigger the Assignment Provisions. If the Arrangement is deemed to have triggered the Assignment Provisions and an assignment fee is payable, such payment could have an adverse effect on the value of our assets and could adversely affect our results of operations or financial condition. Further, although we are not aware of any reported cases of a concession being terminated on such grounds, it is possible that the Egyptian Government could seek to terminate the Egyptian PSCs for breach of the Assignment Provisions.

***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 date of approval of a development and production plan. We and our Block P joint venture owners are evaluating the timing and budgeting for development and exploration activities in the block. We have completed a feasibility study of a standalone production development opportunity of the Venus discovery on Block P and on July 15, 2022 submitted to the EG MMH a plan of development for Block P which on September 16, 2022 was approved by the government of Equatorial Guinea, but there can be no certainty 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.

***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.

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 following are the hedges outstanding at December 31, 2022:

| Settlement Period | Type of Contract | Index | Average Monthly Volumes | Weighted Average Put Price | Weighted Average Call Price |
|---|---|---|---|---|---|
| | | | (Bbls) | (per Bbl) | (per Bbl) |
| January 2023 to March 2023 ... | Collars | Dated Brent | 101,000 | $ 65.00 | $ 120.00 |

The following additional hedges were entered into in 2023:

| Settlement Period | Type of Contract | Index | Average Monthly Volumes | Weighted Average Put Price | Weighted Average Call Price |
|---|---|---|---|---|---|
| | | | (Bbls) | (per Bbl) | (per Bbl) |
| April 2023 to June 2023 .......... | Collars | Dated Brent | 95,500 | $ 65.00 | $ 100.00 |
| July 2023 to September 2023 .. | Collars | Dated Brent | 95,500 | $ 65.00 | $ 96.00 |

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 our 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 limit our ability to perform under their hedging contracts with us. Even if we accurately predict sudden changes, our ability to negate the 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 in 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 may be 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 and other parties. In addition, we may be 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 it finds 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. 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 Gabon or the EGPC. 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 Gabon or the EGPC. Historically, we have had significant account receivables outstanding from governmental entities in Gabon and the EGPC. While the EGPC has made regular payments of these amounts owing, the timing of these payments has historically been longer than the normal industry standard. In the event the Governments of Gabon or Egypt fails to meet their respective obligations, 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. Recent macroeconomic conditions have caused turmoil in the banking sector in the United States and elsewhere. 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, 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 us 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;
- a cybersecurity attack on a vendor or service provider, which could result in supply chain disruptions and 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.

***Events outside of our control, such as the ongoing COVID-19 pandemic and Russia's invasion of Ukraine, could adversely impact our business, results of operations, cash flows, financial condition and liquidity.***

We face risks related to epidemics, outbreaks and other macroeconomic events that are outside of our control. The global or national outbreak of an illness or any other communicable disease or any other public health crisis such as the COVID-19 pandemic, and effects of the occurrence of certain geopolitical events such as the ongoing military conflict between Russia and Ukraine and the slowdown of the Chinese economy could significantly disrupt our business and operational plans and adversely affect our results of operations, cash flows, financial condition and liquidity. Although we are not able to enumerate all potential risks to our business resulting from the ongoing COVID-19 pandemic, the conflict between Russia and Ukraine or the slowdown of the Chinese economy, 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;
- litigation risk and possible loss contingencies related to COVID-19 and its impact, including with respect to commercial contracts, employee matters and insurance arrangements;
- 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 and FSO charter vessel or our counterparties are unable to lift crude oil from our FSO charter vessel;
- we may be subject to actions undertaken by national, regional and local governments and health officials to contain the virus or treat its effects, including travel restrictions and temporary closures;
- 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.

We cannot reasonably estimate the period of time that the COVID-19 pandemic, Russia's invasion of Ukraine and related market 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.***

After terminating its membership with OPEC in 1995, Gabon re-joined OPEC as a full member in July 2016. Historically and from time to time, members of OPEC have entered into agreements to reduce worldwide production of crude oil, including the agreement reached in April 2020 among OPEC member countries and other leading allied producing countries (collectively, "**OPEC+**") to reduce the gap between excess supply and demand in an effort to stabilize the international oil market. Gabon undertook measures to comply with such OPEC+ production quota agreement. As a result, the Minister of Hydrocarbons in Gabon requested that we reduce our production beginning July 2020 and continuing through April 20, 2021 in compliance with the OPEC+ mandate, and we took measures to temporarily reduce our production. In July 2021, OPEC+ agreed to increase production beginning in August 2021 and to gradually phase out prior production cuts by September 2022. The decision to increase in production was reaffirmed by an OPEC+ meeting held on February 2, 2022. However, as a result of the recent decline in oil prices, on October 5, 2022, OPEC+ announced plans to reduce overall oil production by 2 MMBbls per day starting November 2022. We have not received any mandate to reduce its current oil production from the Etame Marin block as a result of the 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.

***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 the 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.

The Gabonese government's oil company may seek to participate in crude oil projects in a manner that could be dilutive to the interest of current license holders, and the Gabonese government is under pressure from the Gabonese labor union to require companies to hire a higher percentage of Gabonese citizens. In 2016, the government of Gabon conducted an audit of our operations in Gabon, covering the years 2013 through 2014. We received the findings from this audit and responded to the audit findings in January 2017. Since providing our response, there have been changes in the Gabonese officials responsible for the audit. We are working with the current representatives to resolve the audit findings. Between 2019 and 2021, the government of Gabon conducted an audit of our operations in Gabon, covering the years 2015 and 2016. While the impact of any adverse findings relating to these assessments is not anticipated to have a materially significant negative impact on our reported earnings or cash flows, we can make no assurances that this will be the case. 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.

In December 2021 and during 2022, the Bank of Central African States ("BEAC"), which is the central bank for 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 2023 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.

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. Accordingly, operations outside the U.S. may be materially affected by host governments. While the laws of each of Gabon and Equatorial Guinea recognize private and public property and the right to own property is protected by law, the laws of each country reserve, at the respective government's discretion, the right to expropriate property and terminate contracts (including the Etame PSC and the Block P PSC) for reasons of public interest, subject to reasonable compensation, determinable by the respective government in our discretion. The terms of the Etame PSC include provisions for, among other things, payments to the government of Gabon for a 13% Royalty Interest based on crude oil production at published prices and payments for a shared portion of "profit oil," based on daily production rates, which such "profit oil" has been and can continue to be taken in-kind through taking crude oil barrels rather than making cash payments.

We have operated in Gabon since 1995 and believe we have good relations with the current Gabonese government. However, there can be no assurance that present or future administrations or governmental regulations in Gabon will not materially adversely affect our operations or cash flows.

The respective applicable laws governing the exploration and production of hydrocarbons in Gabon and Equatorial Guinea (Law No. 002/2019 in Gabon and Law No. 8/2006 in Equatorial Guinea) each provide their respective government officials with significantly broad regulatory, inspective and auditing powers with respect to the performance of petroleum operations, which include the powers to negotiate, sign, amend and perform all contracts entered into between the respective governments and independent contractors. The executive branches of each respective government also retain significant discretionary powers, giving considerable control over the executive, judiciary and legislative branches of each government, and the ability to adopt measures with a direct impact on private investments and projects, including the right to appoint ministers responsible for petroleum operations. Further, in Equatorial Guinea, any new PSC or equivalent agreement for the exploration and exploitation of hydrocarbons is subject to presidential ratification before it can become effective.

In addition, the majority of TransGlobe's current production is located in Egypt. As such, we are now subject to political, economic and other uncertainties in Egypt.

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 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, Equatorial Guinea and Egypt. For example, in Gabon, the Gabonese administration has experienced a succession of large-scale strikes since 2021, general and unlimited strikes have been initiated by workers in the oil sector, by agents of the Ministry of Foreign Affairs, by air traffic controllers and by the collectors of financial regimes. Both Gabon and Equatorial Guinea have had ongoing border disputes, and the Gulf of Guinea, covering Gabon, is often presented as a high risk zone for piracy. There has been significant civil unrest and widespread protests and demonstrations throughout the Middle East, including Egypt, since 2011. Abdel Fattah el-Sisi was elected President of Egypt in 2014 following a few years of widespread protests, demonstrations and civil unrest. Since this time, political and economic stability has returned to the country leading to a positive impact in business confidence, but this remains a jurisdiction with political and economic risk.

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 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.***

Although inflation has been relatively low in recent years, it rose significantly in the second half of 2021 and through 2022. 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, as well as 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 increasing prices of oil, natural gas and NGLs, increased drilling activity in our areas of operations, as well as 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 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 Gabon 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, long-term debt, 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.

In addition, 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.

We 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, the Corruption of Foreign Public Officials Act (Canada) 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 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. Investigations by governmental authorities could have a material adverse effect on our business, results of operations and financial condition.

***There are inherent limitations in all control systems, and misstatements due to error or fraud that could seriously harm our business may occur and not be detected.***

While our management has concluded that our internal control over financial reporting is effective, we do not expect that the relevant internal controls and disclosure controls will prevent or detect all possible errors or all instances of fraud, and this risk is and may continue to be heightened in the context of our integration of TransGlobe's control systems. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the fact that there are resource constraints, and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, an evaluation of controls can only provide reasonable assurance that all material control issues and instances of fraud, if any, have been or will be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistakes. Further, controls can be circumvented by the individual acts of some persons or by two or more persons acting in collusion. The design of any system of controls is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of inherent limitations in any control system designed under a cost-effective approach, misstatements due to error or fraud may occur and not be detected. A failure of the controls and procedures to detect error or fraud could seriously harm our business and results of operations.

***We have identified material weaknesses in our internal control over financial reporting which has caused us to conclude our disclosure controls and procedures and our internal control over financial reporting were not effective as of December 31, 2022 and could, if not remediated, adversely affect our ability to report our financial condition and results of operations in a timely and accurate manner, investor confidence in our company and, as a result, the value of our common stock.***

We are required to evaluate the effectiveness of our disclosure controls and procedures and our internal control over financial reporting on a periodic basis and publicly disclose the results of these evaluations and related matters in accordance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002. We have identified certain material weaknesses in internal control over financial reporting in the areas of (i) accounting for leases, (ii) accounting for complex areas, specifically, business combinations, (iii) consolidation reporting related to recently acquired business operations, and (iv) accounting for income taxes, as described in "Item 9A. Controls and Procedures" of this Form 10-K. As a result of such material weaknesses, our management concluded that our disclosure controls and procedures and our internal control over financial reporting were not effective as of December 31, 2022.

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 our annual or interim consolidated financial statements will not be prevented or detected on a timely basis. We are actively engaged in developing and implementing a remediation plan, as described in "Item 9A. Controls and Procedures" of this Form 10-K, designed to address these material weaknesses, but our remediation efforts are not complete and are ongoing. Although we are working to remedy the ineffectiveness of the Company's internal control over financial reporting, there can be no assurance as to when the remediation plan will be fully developed, when it will be fully implemented or the aggregate cost of implementation. Until our remediation plan is fully implemented, our management will continue to devote significant time and attention to these efforts. If we do not complete our remediation in a timely fashion, or at all, or if our remediation plan is inadequate, there will continue to be an increased risk that we will be unable to timely file future periodic reports with the SEC and that our future consolidated financial statements could contain errors that will be undetected. If we are unable to report our results in a timely and accurate manner, we may not be able to comply with the applicable covenants in our financing arrangements and may be required to seek additional amendments or waivers under these financing arrangements, which could adversely impact our liquidity and financial condition. Further and continued determinations that there are material weaknesses in the effectiveness of the Company's internal control over financial reporting could reduce our ability to obtain financing or could increase the cost of any financing we obtain and require additional expenditures of both money and our management's time to comply with applicable requirements.

Any failure to implement or maintain required new or improved controls, or any difficulties we encounter in their implementation, could result in additional material weaknesses or material misstatement in our consolidated financial statements. Any misstatement could result in a restatement of our consolidated financial statements, cause us to fail to meet our reporting obligations, reduce our ability to obtain financing or cause investors to lose confidence in our reported financial information, leading to a decline in our stock price. We cannot assure you that we will not discover additional weaknesses in our internal control over financial reporting.

We are required to furnish a report by management, and our independent registered public accounting firm is required to provide an attestation report, on the effectiveness of our internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002. If we are unable to comply with the requirements of Section 404 in a timely manner or assert that our internal control over financial reporting is effective, or if our independent registered public accounting firm is unable to provide us with an unqualified report regarding the effectiveness of our internal control over financial reporting, investors could lose confidence in the reliability of our financial statements. This could result in a decrease in the value of our common stock. Failure to comply with the Sarbanes-Oxley Act of 2002 could potentially subject us to sanctions or investigations by the SEC, NYSE, or other regulatory authorities.

Furthermore, as we grow our business, our disclosure controls and internal controls will become more complex, and we may require significantly more resources to ensure the effectiveness of these controls. If we are unable to continue upgrading our financial and management controls, reporting systems, information technology and procedures in a timely and effective fashion, additional management and other resources may need to be devoted to assist in compliance with the disclosure and financial reporting requirements and other rules that apply to reporting companies, which could adversely affect our business, financial position and results of operations.

***We may not have enough insurance to cover all of the risks we face.***

Our business is subject to all of the operating risks normally associated with the exploration for and production, gathering, processing, and transportation of crude oil, natural gas and NGLs, including blowouts, cratering and fire, any of which could result in damage to, or destruction of, crude oil, natural gas and NGLs wells or formations, production facilities, and other property, as well as injury to persons. For protection against financial loss resulting from these 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. However, our insurance coverage may not be sufficient to cover us against 100% of potential losses arising as a result of the foregoing, and for certain risks, such as political risk, nationalization, business interruption, war, terrorism, and piracy, for which we have limited or no coverage. In addition, we are not insured against all risks in all aspects of our business, such as hurricanes. The occurrence of a significant event that we are not fully insured against could have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

***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 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 our title documents which 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.

***We may be exposed to the risk of earthquakes in Alberta.***

The AER monitors seismic activity across the province of Alberta in Canada to assess the risks associated with, and instances of, earthquakes induced by hydraulic fracturing. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, prompting regulatory authorities to investigate the practice further. The AER has developed monitoring and reporting requirements that apply to all oil and natural gas producers working in certain areas where the likelihood of an earthquake is higher, and implemented the requirements in Subsurface Order Nos. 2, 6, and 7 (the “Seismic Protocol Regions”). While we do not have operations in the Seismic Protocol Regions, we own production and working interest facilities and assets in the Harmattan area of west central Alberta and are exposed to the risks of earthquakes in that region. We routinely conduct hydraulic fracturing in our drilling and completion programs.

***There may be valid challenges to title or legislative changes which affect our title to the oil, natural gas and NGLs properties we control in Canada.***

Although title reviews may be conducted in Canada prior to the purchase of oil, natural gas and NGLs producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise. Due in part to the nature of property rights development historically in Canada as well as the common practice of splitting legal and beneficial title, public registries are not determinative of actual rights held by parties. Further, the fragmented nature of oil and gas rights, which may be held by the government or private individuals and companies, and may be split among a great number of different granting documents, means that despite best efforts of parties, latent defects may not be immediately discoverable. As such, our actual interest in properties may accordingly vary from our records. If a title defect does exist, it is possible that we may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on our business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect our title to the oil and natural gas properties that we control in Canada that could impair our activities and result in a reduction of the revenue we receive. Additionally, title claims by Indigenous groups could, among other things, delay or prevent the exploration or development of our properties, which in turn could have a material adverse effect on our business, financial condition, results of operations and prospects.

***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.

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

Our Facility Agreement is for $50 million, none of which had been drawn as of December 31, 2022. 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, 2022, approximately 15% 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 and political unrest in the Middle East and Africa, 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, such as the ongoing COVID-19 pandemic. 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 further 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 value. 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 which 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 and floods), 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 and climate change issues may adversely impact our business, impact our access to investors and financing, and decrease demand for our product***.

An increased expectation that companies address environmental (including climate change), social and governance (“ESG”) matters may have a myriad of impacts on our business. Some investors and lenders are factoring these issues into investment and financing decisions. They may rely upon companies that assign ratings to a company’s ESG performance. Unfavorable ESG ratings, as well as recent activism around fossil fuels, may dissuade investors or lenders from engaging with us in favor of companies in other industries, which could negatively impact our share price or our access to capital.

Moreover, while we have and may continue to create and publish voluntary disclosures regarding ESG matters from time to time, many of the statements in those voluntary disclosures are based on hypothetical expectations and assumptions that may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. Such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring and reporting on many ESG matters.

Approaches to climate change and transition to a lower-carbon economy, including government regulation, company policies, and consumer behavior, are continuously evolving. At this time, we cannot predict how such approaches may develop or otherwise reasonably or reliably estimate their impact on our financial condition, results of operations and ability to compete. However, any long-term material adverse effect on the oil and gas industry may adversely affect our financial condition, results of operations and cash flows.

In Canada, opposition by Indigenous groups to our operations, development or exploration activities may negatively impact us. Opposition by Indigenous groups to the conduct of our operations, development or exploratory activities in any of the jurisdictions in which we conduct business may negatively impact us in terms of public perception, diversion of management’s time and resources, legal and other advisory expenses, and could adversely impact our progress and ability to explore and develop properties.

Some Indigenous groups have established or asserted Indigenous treaty and title rights to portions of Canada. Although there are no Indigenous treaty or title rights claims on lands where we operate, no certainty exists that any lands currently unaffected by claims brought by Indigenous groups will remain unaffected by future claims. Such claims, if successful, could have a material adverse impact on our operations and pace of growth.

Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect asserted or proven Indigenous treaty or title rights and, in certain circumstances, accommodate their concerns. The scope of the duty to consult by federal and provincial governments varies with the circumstances and is often the subject of litigation. The fulfilment of the duty to consult Indigenous people and any associated duties of accommodation may adversely affect our ability, or increase the time required to obtain or renew, permits, leases, licenses and other approvals, or to meet the terms and conditions of those approvals.

Continued development of common law precedent regarding existing laws relating to Indigenous consultation and accommodation as well as the adoption of new laws are expected to continue to add uncertainty to the ability of entities operating in the Canadian oil and gas industry to execute on major resource development and infrastructure projects, including, among other projects, pipelines that could adversely impact our progress and ability to explore and develop properties in Canada. For example, Canada is a signatory to the United Nations Declaration of the Rights of Indigenous Peoples ("UNDRIP") and the principles set forth therein may continue to influence the role of Indigenous engagement in the development of the oil and gas industry in Western Canada. In June 2021, the United Nations Declaration on the Rights of Indigenous Peoples Act (Canada) ("UNDRIP Act") came into force in Canada. The UNDRIP Act requires the Government of Canada to take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives. Adding further uncertainty, on June 29, 2021, the British Columbia Supreme Court issued a judgement in Yahey v British Columbia (the "Blueberry Decision"), in which it determined that the cumulative impacts of industrial development on the traditional territory of the Blueberry River First Nation ("BRFN") in northeast British Columbia had breached BRFN's treaty rights. The Blueberry Decision may lead to similar claims of cumulative effects across Canada in other areas covered by treaties.

***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.

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

The laws and regulations of the U.S., Canada, Egypt, Equatorial Guinea and Gabon 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 liability 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.

These laws and 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. While we believe that we are currently in compliance with environmental laws and 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 it may have limited influence and control. Private litigation or government proceedings brought against us could also result in significant delays in our operations.

***Our failure to comply with applicable laws could subject us to penalties and other adverse consequences.***

We are subject to a wide variety of laws relating to the environment, health and safety, taxes, employment, labor standards, money laundering, terrorist financing, and other matters in the jurisdictions in which they operate. 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. The compliance mechanisms and monitoring programs that we have adopted and implemented may not adequately prevent or detect possible violations of such applicable laws. Investigations by governmental authorities could also have a material adverse effect on our business, results of operations and financial condition.

**Risks Relating to the Facility Agreement**

***A significant level of indebtedness incurred under the 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 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 Facility.***

The Facility Agreement governing our Facility with Glencore 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 borrowing base certificates, conduct of business, maintenance of property, maintenance of insurance, entry into certain derivatives contracts, restrictions on the incurrence of liens, indebtedness, asset dispositions, restricted payments. Restrictions contained in the Facility governing any future indebtedness may reduce our ability to incur additional indebtedness, engage in certain transactions or capitalize on acquisition or other business opportunities. Any future indebtedness under the 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 flow to payments of our indebtedness and other financial obligations, thereby reducing the availability of our cash flow 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.

Our ability to comply with these 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 declined 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 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 restrictive covenants under the Facility.

***If we experience in the future a continued period of low commodity prices, our ability to comply with the Facility's debt covenants may be impacted.***

Under the Facility Agreement, we are subject to certain debt covenants, including that (i) the ratio of Consolidated Total Net Debt to EBITDAX (as each term is defined in the Facility Agreement) for the trailing 12 months shall not exceed 3.0x and (ii) consolidated cash and cash equivalents shall not be lower than $10.0 million. We were in compliance with covenants under the Facility through December 31, 2022; however, commodity prices have been extremely volatile in recent history and a protracted future decline in commodity prices could cause us to not be in compliance with certain financial covenants under the Facility in future periods. A breach of the covenants under the Facility would cause a default, potentially resulting in acceleration of all amounts outstanding under the Facility. Certain payment defaults or acceleration under the Facility could cause a cross-default or cross-acceleration of other future outstanding indebtedness. Such a cross-default or cross-acceleration could have a wider impact on our liquidity than might otherwise arise from a default or acceleration of a single debt instrument. If an event of default occurs, or if other future debt agreements cross-default, and the lenders under the affected debt agreements accelerate the maturity of any loans or other debt outstanding, we may not have sufficient liquidity to repay all of our outstanding indebtedness.

***The borrowing base under the Facility may be reduced pursuant to the terms of the 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 Facility for a portion of our capital needs. The initial maximum borrowing base under the Facility is $50.0 million (which maximum is reduced to $43.75 million beginning on October 1, 2023) and is re-determined on March 31 and September 30 of each year. Borrowings under the Facility are limited to a borrowing base amount calculated pursuant to the Facility Agreement based on our proved producing reserves and a portion of our proved undeveloped reserves.

The lenders will re-determine the borrowing base based on forecasts of cash flow and debt service projections with respect to the borrowing base assets, which may result in a reduction of the borrowing base.

In the future, we may not be able to access adequate funding under the 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 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.

***Restrictive debt covenants could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.***

The Facility Agreement contains a number of significant affirmative and negative covenants that, among other things, restrict our ability to:

- dispose of assets;
- enter into guarantees or indemnities;
- incur indebtedness;
- enter into certain material contracts;
- merge or consolidate, or transfer all or substantially all of our assets and the assets of our subsidiaries; or
- pursue other corporate activities.

Also, the Facility Agreement requires us to maintain compliance with certain financial covenants. Our ability to comply with these financial covenants may be affected by events beyond our control, and, as a result, we may be unable to meet these financial covenants. These financial covenants could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants under the Facility Agreement. A breach of any of these covenants or our inability to comply with the required financial covenants could result in an event of default under the Facility Agreement. When oil and/or natural gas prices decline for an extended period of time or when our liquidity is constrained, our ability to comply with these covenants becomes more difficult. Although we are currently in compliance with these covenants, if in the future oil and gas prices decline for an extended period of time, we may default on one or more of these covenants. Such a default, if not cured or waived, may allow the Lenders to accelerate the related indebtedness and could result in acceleration of any other indebtedness to which a cross-acceleration or cross-default provision applies.

An event of default under the Facility Agreement would permit the Lenders to cancel all commitments to extend further credit under the Facility. Furthermore, if we were unable to repay the amounts due and payable under the Facility Agreement, the Lenders could proceed against the collateral granted to them to secure that indebtedness. In the event that the Lenders accelerate the repayment of our borrowings under the Facility, we and our subsidiaries may not have sufficient assets to repay that indebtedness. As a result of these restrictions, we may be:

- limited in how we conduct our business;
- unable to raise additional debt or equity financing during general economic, business or industry downturns; or
- unable to compete effectively or to take advantage of new business opportunities.

**Risks Relating to Ownership of Our Common Stock**

***The price of our Common Stock may fluctuate significantly.***

Our common stock currently trades on the NYSE and the 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, and effect share buybacks, with respect to our common stock; however, our ability to take these actions in the future may be limited and no assurance can be given that we will be able to pay dividends to our stockholders or effect share buybacks in the future at indicated levels or at all.***

On February 14, 2023, we announced that 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. On November 1, 2022, we announced the approval by our board of directors of the share buyback program, which provides for an aggregate purchase of currently outstanding common stock up to $30 million over 20 months. We also announced that we entered into the 10b5-1 Plan in order to effectuate, share buybacks in an aggregate amount of up to $30 million which commenced on November 17, 2022, and ends no later than August 16, 2024. To the extent we have adequate cash on hand and cash flows from operations, we will consider continuing to take these actions in the future. Payment of future dividends and effectuation of share buybacks, 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 the terms on which we will effectuate share buybacks in the future 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 our common stock in the future, will have on the market price of our common stock. Sales or an additional offering of substantial numbers 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 or may be unable 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 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*."

## Item 3. Legal Proceedings

We are subject to litigation claims and governmental and regulatory proceedings arising in the ordinary course of business. 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 March 31, 2023, based upon information received from our transfer agent and brokers and nominees, there were approximately 80 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*

On November 3, 2021, we announced that our board of directors adopted a quarterly cash dividend policy of an expected $0.0325 per common share per quarter commencing in the first quarter of 2022. The following table is a schedule of our dividends paid during 2022:

| Dividend Payment Date | Amount per common share | Record Date |
|---|---|---|
| March 18, 2022 | $ 0.0325 | February 18, 2022 |
| June 24, 2022 | $ 0.0325 | May 25, 2022 |
| September 23, 2022 | $ 0.0325 | August 25, 2022 |
| December 22, 2022 | $ 0.0325 | November 22, 2022 |
| Aggregate per share amount paid in 2022 | $ 0.1300 | |

In connection with the acquisition of TransGlobe, we announced our intention, following consummation of the acquisition, to have an annualized dividend target of $0.25 per share beginning in the first quarter of 2023, with payments to be made quarterly.

In the first quarter of 2023, we announced that our board of directors increased the quarterly cash dividend to $0.0625 per common share. On February 14, 2023, our board of directors declared a quarterly cash dividend of $0.0625 per common share, which was payable on March 31, 2023 to stockholders of record at the close of business on March 24, 2023.

In connection with the RBL facility, we are required to provide a cash flow projection prior to any distribution, share buyback, or stock repurchase. As long as a group liquidity test is above the required ratio outlined in the RBL facility agreement, and no event of default exists, we may make distributions, buyback shares, or repurchase stock without further approval. In the event the liquidity test is not met, an approval or waiver would need to be obtained from Glencore in order to make distributions, buyback shares, or repurchase stock. For the year ended December 31, 2022, no specific approval or waivers were required to make distributions or repurchase stock.

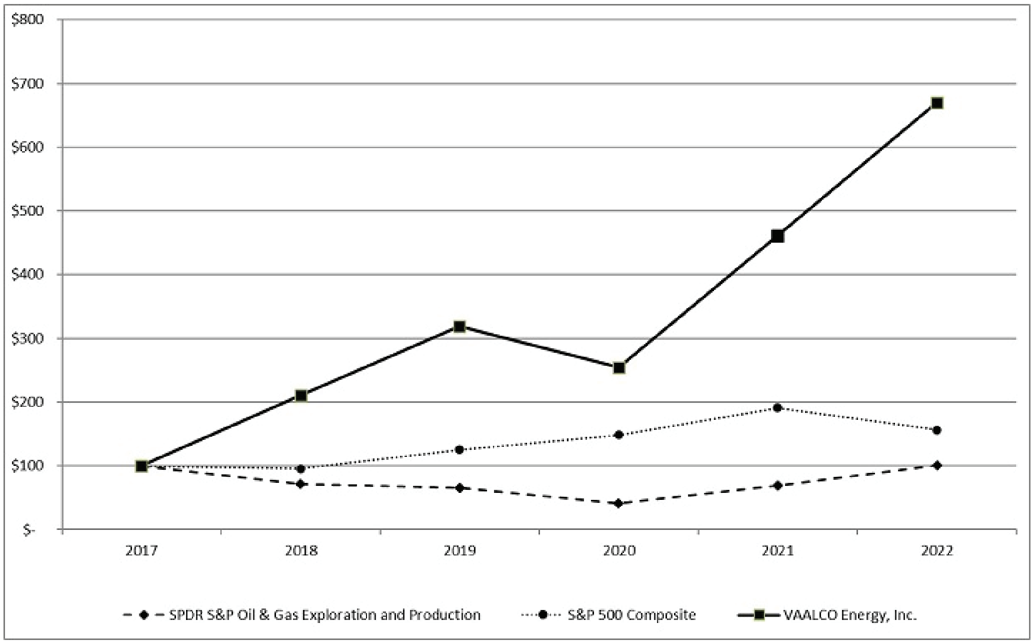
To the extent we have adequate cash on hand and cash flows from operations, we will consider paying additional cash dividends on a quarterly basis; however, any future dividend payments, if any, will be at the discretion of the board of directors after taking into account various factors, including current 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 29, 2017 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.




| | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|
| SPDR S&P Oil & Gas Exploration and Production | $ 100 | $ 72 | $ 65 | $ 41 | $ 69 | $ 100 |
| S&P 500 Composite | $ 100 | $ 96 | $ 125 | $ 148 | $ 191 | $ 156 |
| VAALCO Energy, Inc. | $ 100 | $ 211 | $ 319 | $ 254 | $ 461 | $ 670 |

***Unregistered Sales of Equity Securities and Use of Proceeds***

There were no sales of unregistered securities during the quarter ended December 31, 2022 that were not previously reported on a Current Report on Form 8-K.

***Issuer Repurchases of Common Stock***

On November 18, 2022, we announced that VAALCO had entered into the 10b5-1 Plan in order to effectuate, share buybacks in an aggregate amount of up to $30 million, which commenced on November 17, 2022 and ends no later than August 16, 2024. The 10b5-1 Plan provides for share buybacks through open market purchases in compliance with Rule 10b-18 under the Exchange Act. Payment for shares repurchased under the share buyback program will be funded using VAALCO's cash on hand and cash flow from operations.

In connection with the RBL facility, we are required to provide a cash flow projection prior to any distribution, share buyback, or stock repurchase. As long as a group liquidity test is above the required ratio outlined in the RBL facility agreement, and no event of default exists, we may make distributions, buyback shares, or repurchase stock without further approval. In the event the liquidity test is not met, an approval or waiver would need to be obtained from Glencore in order to make distributions, buyback shares, or repurchase stock. For the year ended December 31, 2022, no specific approval or waivers were required to make distributions or repurchase stock.

The below table shows the repurchases of our equity securities related to share repurchase program during the fourth quarter of the fiscal year ended December 31, 2022:

| Period | Total Number of Shares Purchased | Average Price Paid per Share | Total Number of Shares Purchased as Part of Publicly Announced Programs | Maximum Amount that May Yet Be Used to Purchase Shares Under the Program |
|---|---|---|---|---|
| November 1, 2022 - November 30, 2022 | 288,758 | $ 5.21 | 288,758 | $ 28,500,463 |
| December 1, 2022 - December 31, 2022 | 282,163 | $ 5.34 | 282,163 | $ 27,000,767 |
| Total | 570,921 | | 570,921 | |

The following table shows the repurchases of our equity securities related to our share repurchase program after December 31, 2022 through March 31, 2023:

| Period | Total Number of Shares Purchased | Average Price Paid per Share | Total Number of Shares Purchased as Part of Publicly Announced Programs | Maximum Amount that May Yet Be Used to Purchase Shares Under the Program |
|---|---|---|---|---|
| January 1, 2023 - January 31, 2023 | 350,832 | $ 4.29 | 350,832 | $25,502,669 |
| February 1, 2023 - February 28, 2023 | 326,992 | $ 4.61 | 326,992 | $24,003,172 |
| March 1, 2023 - March 31, 2023 | 303,176 | $ 4.97 | 303,176 | $22,503,206 |
| Total | 981,000 | | 981,000 | |

We continue to purchase shares under the 10b5-1 Plan for share repurchases from and including April 2023.

**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 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 2021 as compared with 2020, refer to Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2021 Form 10-K, which was filed with the SEC on March 11, 2022. 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

VAALCO is a Houston, Texas based independent energy company engaged in the acquisition, exploration, development and production of crude oil, natural gas and NGLs. As operator, we have production operations and conduct exploration activities in Gabon, West Africa, Egypt and Canada. We also have opportunities to participate in development and exploration activities in Equatorial Guinea, West Africa. For further discussion of our four operating segments see "*Item 1. Business – Segment and Geographical Information –* "*Gabon Segment*", "*Egypt Segment",* "*Canada Segment",* and "*Equatorial Guinea Segment*"". As discussed further in Note 4 to the Financial Statements, we have discontinued operations associated with our activities in Angola, West Africa and Yemen.

Our primary source of revenue historically has been from the Etame PSC related to the Etame Marin block located offshore Gabon in West Africa. The Etame Marin block covers an area of approximately 46,200 gross acres located 20 miles offshore in water depths of approximately 250 feet. Currently, our working interest in the Etame Marin block is 58.8%, and we are designated as the operator on behalf of the Etame Consortium. 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% in June 2026 when the back-in carried interest increases to 10%.

We are also a member of a consortium with BW Energy and Panoro Energy (the "BWE Consortium"). The BWE Consortium has been provisionally awarded two blocks in the 12th Offshore Licensing Round in Gabon. The award is subject to concluding the terms of PSCs with the Gabonese government. BW Energy will be the operator with a 37.5% working interest, with VAALCO (37.5% working interest) and Panoro Energy (25% working interest) as non-operating joint owners. The two blocks, G12-13 and H12-13 are adjacent to our Etame PSC as well as BW Energy and Panoro's Dussafu PSC offshore Southern Gabon and cover an area of 2,989 square kilometers and 1,929 square kilometers, respectively.

On October 13, 2022, VAALCO and VAALCO Energy Canada ULC ("AcquireCo"), an indirect wholly-owned subsidiary, completed the previously announced business combination involving TransGlobe Energy Corporation ("TransGlobe"), whereby AcquireCo acquired all of the issued and outstanding TransGlobe common shares pursuant to a plan of arrangement (the "Arrangement") and TransGlobe became a direct wholly-owned subsidiary of AcquireCo and an indirect wholly-owned subsidiary of VAALCO in accordance with the terms of an arrangement agreement entered into by VAALCO, AcquireCo and TransGlobe on July 13, 2022 (the "Arrangement Agreement"). Prior to the Arrangement, TransGlobe was a cash flow-focused oil and gas exploration and development company whose activities were concentrated in Egypt and Canada. The post-Arrangement company (the "Combined Company") is an African-focused operator with a diverse portfolio of assets in Gabon, Egypt, Equatorial Guinea and Canada. See Note 4 to the consolidated financial statements for further discussion regarding the Arrangement.

## RECENT DEVELOPMENTS

### *Share Buyback Program*

On November 1, 2022, VAALCO announced that its board of directors formally ratified and approved the share buyback program that was announced on August 8, 2022 in conjunction with our business combination with TransGlobe. The board of directors also directed management to implement 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 Exchange Act. The 10b5-1 Plan provides for an aggregate purchase of currently outstanding common stock up to $30 million over 20 months. Payment for shares repurchased under the share buyback program will be funded using cash on hand and cash flow from operations.

The actual timing number and value of shares repurchased under the share buyback program will depend on a number of factors, including constraints specified in the Plan, VAALCO's stock price, general business and market conditions, and alternative investment opportunities. Under the Plan, our third-party broker, subject to SEC regulations regarding certain price, market, volume and timing constraints, has authority to purchase VAALCO common stock in accordance with the terms of the Plan.

***TransGlobe Arrangement***

On October 13, 2022, VAALCO and AcquireCo completed the previously announced business combination with TransGlobe whereby AcquireCo acquired all of the issued and outstanding TransGlobe common shares pursuant to the Arrangement and TransGlobe became a direct wholly-owned subsidiary of AcquireCo and an indirect wholly-owned subsidiary of VAALCO, pursuant to the Arrangement Agreement.

Additionally, prior to the effective time of the Arrangement, TransGlobe repaid outstanding obligations and liabilities owned under TransGlobe's credit facility with ATB Financial, representing approximately C$4.1 million. On December 19, 2022, TransGlobe, as an indirect wholly-owned subsidiary of VAALCO, voluntarily delivered a notice of termination to ATB Financial relating to the ATB Facility. As of December 31, 2022, no amounts were drawn on the revolving loan facility. On January 5, 2023, the ATB Facility was formally closed.

For the twelve months ended December 31, 2022, included in the line item "Other (expense) income, net" is $14.6 million of transactions costs associated with the Arrangement with TransGlobe.

***Entry into a Facility Agreement***

On May 16, 2022, VAALCO Gabon (Etame), Inc. (the "Borrower"), a wholly owned subsidiary of VAALCO, entered into a facility agreement (the "Facility Agreement") by and among VAALCO, VAALCO Gabon and, together with VAALCO, the "Guarantors"), Glencore Energy UK Ltd., as mandated lead arranger, technical bank and facility agent ("Glencore"), the Law Debenture Trust Corporation P.L.C., as security agent, and the other financial institutions named therein (the "Lenders"), providing for a senior secured reserve-based revolving credit facility (the "Facility") in an aggregate maximum principal amount of up to $50.0 million. Subject to certain conditions, the Borrower may agree with any Lender or other bank or financial institution to increase the total commitments available under the Facility by an aggregate amount not to exceed $50.0 million (any such increase, an "Additional Commitment"). Beginning October 1, 2023 and thereafter on April 1 and October 1 of each year during the term of the Facility, the Initial Total Commitment, as increased by any Additional Commitment, will be reduced by $6.25 million. See "—*Capital Resources and Liquidity – RBL Facility Agreement*" for more information regarding the Facility.

***Marine Construction Agreement for Subsea Reconfiguration***

On March 17, 2022, VAALCO Gabon, a wholly owned subsidiary of VAALCO, entered into the Marine Construction Agreement with DOF Subsea, to support the subsea reconfiguration in connection with the replacement of the then-existing FPSO vessel with a FSO vessel at the Etame Marin field offshore Gabon. Pursuant to the Marine Construction Agreement, DOF Subsea agreed to, among other things, provide all personnel, crew and equipment necessary to assist in the reconfiguration of the Etame field subsea infrastructure to accommodate all field production to the flow to the FSO, which conversion included (i) assistance with retrieval of over 5,000 meters of new flexible pipelines from a manufacturing facility in the United Kingdom, transporting the pipelines to Gabon and installing the pipelines in the Etame field, (ii) performing the retrieval and relocation of existing in-field flowlines and umbilicals to accommodate the reconfigured field development plan and (iii) assistance in the connection of new risers to the FSO. Pursuant to the Marine Construction Agreement, DOF Subsea provided an offshore construction vessel to facilitate the performance of the Services. In October 2022, we completed the FSO installation and field reconfiguration at Etame field.

***Recent Operational Updates***

***NYSE Noncompliance Notice***

On April 3, 2023, the Company was notified by the New York Stock Exchange (the "NYSE") that it was not in compliance with the NYSE's continued listing requirements under the timely filing criteria established in Section 802.01E of the NYSE Listed Company Manual as a result of its failure to timely file its Annual Report on Form 10-K for the fiscal year ended December 31, 2022. By filing this report, the Company believes it has remedied its non-compliance.

***Gabon Operations Update***

***Charter Agreement for the Floating Storage and Offloading Unit in Gabon***

In August of 2021, we and our co-venturers at Etame approved the FSO Agreements with World Carrier to replace the existing FPSO with an FSO. The FSO Agreements required a prepayment of $2 million gross ($1.2 million net to VAALCO) in 2021 and $5 million gross ($3.2 million net to VAALCO) in 2022 of which $6 million will be recovered against future rentals.

On October 19, 2022, the replacement of the existing FPSO was completed and we signed the final acceptance certificate, at which time control of the FSO vessel transferred to us. The new FSO has been named "Teli" (renamed from "Cap Diamant") and is on site and accepting oil at the Etame Marin block.

Total field conversion expenses were $122 million gross ($77 million net to VAALCO).

The FPSO charter we were party to prior to the FSO installation was set to expire in September 2022, but on September 9, 2022 we signed an addendum to the FPSO contract which extended the use of the FPSO through October 4, 2022, and ratified certain decommissioning and demobilization items associated with exiting the contract. Pursuant to the addendum, VAALCO Gabon agreed to pay the charterer day rate of $150,000 from August 20, 2022 through October 4, 2022 and other demobilization fees totaling $15.3 million on a gross basis ($8.9 million net to VAALCO).

***2021/2022 Drilling Campaign***

In conjunction with the 2021/2022 drilling program, that began in December 2021, we executed a contract with Borr Jack-Up XIV Inc., an affiliate of Borr Drilling Limited, to drill a minimum of three wells with options to drill additional wells. In December 2021, we spudded the Etame 8H-ST, the first well of the 2021/2022 drilling program. In February 2022 we completed the drilling of the Etame 8H-ST well and moved the drilling rig to the Avouma platform to drill the Avouma 3H-ST development well, which targeted the Gamba reservoir. The Etame 8H-ST demonstrated an initial flow rate of approximately 5,000 gross barrels of oil per day BOPD, 2,560 BOPD net to VAALCO's 58.8% working interest in 2022. The 8H-ST was shut in due to Hydrogen sulfide that arose during the drilling process, but a side track was performed to rectify this and resume production. In April 2022, the Avouma 3H-ST well was completed and brought online with an initial production rate of approximately 3,100 gross BOPD, 1,589 BOPD net to VAALCO's 58.8% working interest in 2022.

In July 2022 we completed the South Tchibala 1HB-ST well on the Avouma platform, targeting the Gamba reservoir and also testing the Dentale formation. The section of the Gamba sand encountered was not economically viable to complete in this wellbore. However, we did discover two potential zones, the Dentale D1 and Dentale D9 zones for development. The well was completed in the Dentale D1 formation and brought online in July with an initial production rate of approximately 293-390 gross BOPD, 150-200 BOPD net to VAALCO's 58.8% working interest in 2022. The Dentale D9 well is temporarily shut-in, however; we plan to evaluate and recomplete the D9 zone during the next drilling campaign.

Following the completion of the South Tchibala 1HB-ST well, the rig was mobilized to the Southeast Etame North Tchibala Platform to drill the North Tchibala 2H-ST ("ETBNM 2H-ST") well, targeting the Dentale formation, which is productive in this area of the Etame license. This mobilization was delayed by two weeks due to weather and the rig began operations on the well in late July. After setting up the equipment and completing operations to re-enter the well, VAALCO began drilling the North Tchibala 2H-ST well on August 8, 2022. The North Tchibala 2H-ST well was brought online in early November and flowed at a low, controlled rate to allow for cleanup and to minimize negative impact to the completion. Through end of January 2023, the well flowed, with temporary interruptions for operational activity and shut-ins for pressure build up analysis. During this time, the well produced approximately 18,500 gross barrels of oil, or about 250 gross bopd and recovered about 36% of injected completion fluid. Cleanup is continuing and pressure transient analysis indicates that both completed zones may be contributing. The well is naturally flowing with no water production and stable reservoir pressure indicating minimal depletion.

Following the drilling campaign, we utilized the rig to perform a workover on the North Tchibala 1H ("ETBNM 1H") well due to a safety valve in the well that required replacement. With the rig already on site it was easier and more economic to utilize the rig to complete the workover following the completion of the North Tchibala 2H-ST well. The final well operation performed by the rig was another workover, the Southeast Etame 4-H (“ETSEM-4H”) well, which restored production to between 1,000 and 1,500 gross BOPD upon completion, following the well going offline in early September as a result of an upper ESP failure and we were unable to restart the upper ESP or the lower ESP to restore production. Utilizing the rig for the workovers has optimized the total cost of the 2021/2022 drilling campaign at Etame.

After the execution of the workovers the drilling rig was released on November 17, 2022.

We estimate the cost of the current 2021/2022 drilling program with four wells and two workovers to be $180 million, or $114 million, net to VAALCO’s participating interest. For 2022, we incurred approximately $148 million, or about $94 million net to VAALCO’s participating interest.

***Acquisition of Additional Working Interest at Etame Marin Block***

In November 2020, we signed a SPA to acquire Sasol’s 27.8% working interest in the Etame Marin block offshore Gabon. On February 25, 2021, we completed the acquisition of Sasol’s 27.8% working interest in the Etame Marin block offshore Gabon pursuant to the SPA. The effective date of the transaction was July 1, 2020. Prior to the Sasol Acquisition, we owned and operated a 31.1% working interest in Etame. The Sasol Acquisition increased our working interest to 58.8%. As a result of the Sasol Acquisition, the net portion of production and costs relating to our Etame operations increased from 31.1% to 58.8%. Reserves, production and financial results for the interests acquired have been included in our results for periods after February 25, 2021. All assets and liabilities associated with Sasol’s interest in Etame Marin block, including crude oil, natural gas and NGLs properties, asset retirement obligations and working capital items were recorded at their fair value. As a result of comparing the purchase price to the fair value of the assets acquired and liabilities assumed, a $7.7 million bargain purchase gain was recognized. A bargain purchase gain of $5.2 million is included in “*Other (expense) income, net*” under “*Other income (expense)*” in the consolidated statements of operations and comprehensive income (loss) for the year ended December 31, 2021. An income tax benefit of $2.5 million, related to the bargain purchase gain, is also included in the consolidated statements of operations and comprehensive income (loss). The reason for the bargain purchase gain is mainly due to the lower crude oil price outlook used when the SPA was signed, November 17, 2020, and the higher oil price outlook on February 25, 2021, when the fair value of the reserves associated with the Sasol Acquisition were determined.

Under the terms of the SPA, a contingent payment of $5.0 million was payable to Sasol should the average Dated Brent price over a consecutive 90-day period from July 1, 2020 to June 30, 2022 exceed $60.00 per barrel. Included in the purchase consideration was the fair value, at closing, of the contingent payment due to Sasol. The conditions related to the contingent payment were met and on April 29, 2021, we paid the $5.0 million contingent amount to Sasol in accordance with the terms of the SPA.

The actual impact of the Sasol Acquisition for the year ended December 31, 2022 and 2021 was an increase to “C*rude oil, natural gas and NGLs sales*” in the consolidated statements of operations and other comprehensive income (loss) of $144.8 million and $84.6 million, respectively, and a $14.6 million and $29.3 million increase to “*Net income*”, respectively, in the consolidated statements of operations and other comprehensive income (loss).

***Egypt Operations Update***

We continued to use the EDC-64 rig in its Eastern Desert drilling campaign. During the quarter, we drilled and cased two development wells and drilled two exploration wells. A third development well, the Arta-77Hz, as discussed below, was brought online in the first quarter of 2023.

The M-17 well was drilled to a total depth of 1,900 meters targeting Asl reservoirs in the M Field. The well was fully logged and evaluated. The Asl-A reservoir has an internally estimated 11.5 meters of net oil pay, 12.2 m of net oil pay in the Asl-B reservoir and 1.1 m of net oil pay in the Asl-D reservoir. The Asl-A reservoir was perforated and put on production with a current rate of 348 BOPD at a 42% water cut (heavy crude, field estimate) (Initial production over 30 days was 406 BOPD at a 23% water cut).

The NWG-2INJ-1A well was drilled to a total depth of 1,318 meters targeting the Nukhul reservoir. Initially intended as a water injector, the well encountered strong oil and gas shows in the Nukhul. The well was fully logged and evaluated with an internally estimated 6.4 meters of net oil pay in the Nukhul. This well was put on production with a current rate of 122 BOPD (heavy crude, field estimate) at 40% water cut.

Two exploration wells were drilled in the north of the Petrobakr concession. Both wells targeted the Red Bed reservoir trend that successfully produces at the NWG-38 Field in this area. NWG-44A was drilled to a depth of 1,737 meters and NWG-46X was drilled to a depth of 1,463 meters. Both wells encountered minor oil and gas shows in the Red Bed formation, however the zone was tight. Both wells were plugged and abandoned as they were dry.

Late in the fourth quarter of 2022, we initiated the Arta horizontal pilot program in the Arta Field by successfully drilling the Arta-77Hz well targeting the Nukhul reservoir. The well was drilled to a total depth of 2,409 meters MD (1,182 meters TVD). The lateral was successfully drilled through the Nukhul reservoir encountering 1,363 meters of reservoir with good oil and gas shows. Subsequent to the quarter, the well was completed through the lateral section with a 14-stage cemented frac sleeve liner. The well was multi-stage stimulated and put on production in the first quarter of 2023.

The SGZ-6X well remains shut-in. We continue to evaluate our strategic options. There was no production from South Ghazalat due to the SGZ-6X remaining shut-in. There is a planned workover for this well in 2023 to resume production.

***Canada Operations Update***

In Canada, TransGlobe planned a seven horizontal Cardium reservoir wells (four 2-mile, and three 1-mile) drilling campaign in the South Harmattan area during 2022. Four of those wells were brought on production in the third quarter prior to the acquisition agreement and one well was brought on production in the fourth quarter of 2022 and the remaining two wells were brought on production during the first quarter of 2023.

The 4-10-29-3W5 well drilled in July 2022 and was completed and brought on production in late December 2022. As of the first quarter of 2023, the well is currently producing at a field estimated rate of 100 BOPD. The 4-18-29-3W5 and 4-24-29-4W5 wells were completed in the fourth quarter of 2022 and brought on production in the first quarter of 2023.

The 2023 drilling campaign commenced in January 2023 with the drilling of 12-12-30-4W5, spud on January 28, 2023. The well was drilled to a total depth of 6,713 meters. The second well of the program, 16-30-29-3W5, spud on February 22, 2023, and is currently being drilled.

## CAPITAL RESOURCES AND LIQUIDITY

***Cash Flows***

Our cash flows for the years ended December 31, 2022 and 2021 are as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2022** | **2021** | **Increase (Decrease) in 2022 over 2021** |
| | | *(in thousands)* | |
| Net cash provided by operating activities before changes in operating assets and liabilities | **$ 127,817** | $ 62,798 | $ 65,019 |
| Net change in operating assets and liabilities | **1,101** | (12,589) | 13,690 |
| Net cash provided by continuing operating activities | **128,918** | 50,209 | 78,709 |
| Net cash used in discontinued operating activities | **(72)** | (92) | 20 |
| Net cash provided by operating activities | **128,846** | 50,117 | 78,729 |
| Net cash used in investing activities | **(123,211)** | (39,063) | (84,148) |
| Net cash used in financing activities | **(17,955)** | (57) | (17,898) |
| Effects of exchange rate changes on cash | **(218)** | — | (218) |
| Net change in cash, cash equivalents and restricted cash | **$ (12,538)** | $ 10,997 | $ (23,535) |

The $65.0 million increase in net cash provided by our operating activities before changes in operating assets and liabilities for the year ended December 31, 2022 compared to the same period of 2021 was due to higher pricing, more production and the increased number of producing wells partially offset by negative changes due to higher realized losses on derivatives. The net increase in changes provided by operating assets and liabilities of $13.7 million for the year ended December 31, 2022 compared to the same period of 2021 was primarily related to increases in accounts payable partially offset by changes in prepayments and other assets and crude oil inventory and other changes.

The $84.1 million increase in net cash used in investing activities during the twelve months ended December 31, 2022 was due to increases in cash capital spending in 2022 for items to related to the 2021/2022 drilling campaign and the Etame field reconfiguration of $146.4 million, $13.5 million of cash used in the Egypt and Canadian operations for property and equipment partially offset by $36.7 million of cash acquired in the TransGlobe acquisition. For the twelve months ended

December 31, 2021, net cash used in investing activities was due to cash of $22.5 million used in the purchase of Sasol's interest in the Etame Block and $16.6 million for property and equipment on a cash basis.

Net cash used in financing activities during the year ended December 31, 2022 included $9.4 million dividends paid to common shareholders, $3.8 million for treasury stock purchases made under our stock repurchase plan or as a result of tax withholding on options exercised and vested restricted stock as discussed in Note 17 to our consolidated financial statements, $2.1 million in deferred financing costs and $3.0 million related to principal finance lease payments, partially offset by $0.3 million in proceeds from options exercised. For the year ended December 31, 2021, net cash used in financing activities included $1.4 million for treasury stock as a result of tax withholding on options exercised and vested restricted stock as discussed in Note 17 to our consolidated financial statements, partially offset by $1.3 million in proceeds from options exercised.

***Capital Expenditures***

In February 2020, we fully complied with the capital and other commitments associated with the 2018 PSC Extension.

During 2022, we had accrual basis expenditures attributable to continuing operations of $434.4 million, that includes $162.4 million for Gabon, $168.0 million for Egypt, $103.3 million for Canada and $0.7 million for the corporate offices, compared to $79.2 million for 2021. The 2022 capital expenditures include TransGlobe assets acquired for stock. The difference between capital expenditures and the property and equipment expenditures reported in the consolidated statements of cash flows is attributable to changes in accruals for costs incurred but not yet invoiced or paid on the report dates. Capital expenditures in 2022 were attributable to expenditures related to the 2021/2022 drilling program, the Etame field reconfiguration and drilling activity in Egypt and Canada. Capital expenditures in 2021 were attributable to expenditures related to the 2021/2022 drilling program and the Sasol acquisition. See table below in "*Capital Resources, Liquidity and Cash Requirements*" for further information.

***Regulatory and Joint Interest Audits***

We are subject to periodic routine audits by various government agencies in Gabon, 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 Note 12 to the Consolidated Financial Statements for further discussion.

***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.

The following are the hedges outstanding at December 31, 2022:

| Settlement Period | Type of Contract | Index | Average Monthly Volumes | Weighted Average Put Price | Weighted Average Call Price |
|---|---|---|---|---|---|
| | | | (Bbls) | (per Bbl) | (per Bbl) |
| January 2023 to March 2023 ... | Collars | Dated Brent | 101,000 | $ 65.00 | $ 120.00 |

The following additional hedges were entered into in 2023:

| Settlement Period | Type of Contract | Index | Average Monthly Volumes | Weighted Average Put Price | | Weighted Average Call Price | |
|---|---|---|---|---|---|---|---|
| | | | (Bbls) | (per Bbl) | | (per Bbl) | |
| April 2023 to June 2023 .......... | Collars | Dated Brent | 95,500 | $ | 65.00 | $ | 100.00 |
| July 2023 to September 2023 .. | Collars | Dated Brent | 95,500 | $ | 65.00 | $ | 96.00 |

***Cash on Hand***

At December 31, 2022, we had unrestricted cash of $37.2 million. 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.

We currently sell our crude oil production from Gabon under a crude oil sales and marketing agreement ("COSMA") with Glencore. Under the COSMA all oil produced from the Etame G4-160 Block offshore Gabon from August 2022 through the final maturity date of the Facility, expected to be May 15, 2027, will be bought and marketed by Glencore, with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors. Sales with Glencore are normally settled 30 days from the delivery date.

Revenues associated with the sales of our crude oil in Egypt are recognized by reference to actual volumes sold and quoted market prices in active markets for Dated Brent, 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. For reporting purposes, we record the EGPC’s share of production as royalties which are netted against revenue. With respect to taxes in Egypt, our income taxes under the terms of the Merged Concession Agreement are the liability of TransGlobe Petroleum International ("TGPI"), a wholly-owned indirect subsidiary of VAALCO. TGPI's income taxes are paid by EGPC on behalf of TGPI out of EGPC’s production entitlement. The income taxes paid to the Arab Republic of Egypt on behalf of TGPI are recognized as oil and gas sales revenue and income tax expense for reporting purposes.

In the period of October 14 through December 31, 2022, all sales in Egypt were to EGPC. Sales to EGPC are normally settled two to four weeks from delivery.

Revenues from the sale of crude oil, natural gas, condensate and NGLs in Canada are recognized by reference to actual volumes delivered at contracted delivery points and prices. Prices are determined by reference to quoted market prices in active markets for crude oil, natural gas, condensate, and NGLs based on product, each adjusted according to specific terms and conditions applicable per the sales contracts. Revenues are recognized net of royalties and transportation costs. Revenues are measured at the fair value of the consideration received.

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

***Capital Resources, Liquidity and Cash Requirements***

Historically, 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 in the Etame Marin block. 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 and cash flow from operations, including the addition of our Egypt and Canada segments, to support our current cash requirements, including the FSO charter, drilling programs, 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***

On January 19, 2022, legacy subsidiaries of TransGlobe executed the Merged Concession Agreement with EGPC to update and merge TransGlobe's three Egyptian concessions in West Bakr, West Gharib and NW Gharib (the "Merged Concession"). The modernization payments under the Merged Concession Agreement total $65.0 million and are payable over six years from the Merged Concession Effective Date. Under the Merged Concession Agreement, we will be required to pay an additional $10.0 million on February 1 for each of the next three years. In addition, we have committed to spending a minimum of $50.0 million over each five-year period for the 15 years of the primary term (totaling $150.0 million). Our ability to make scheduled payments arising from the Merged Concession Agreement will depend on our financial condition and operating performance, which is subject to then prevailing economic, industry and competitive conditions and to certain financial, business, legislative, regulatory and other factors beyond our control.

***RBL Facility Agreement and Available Credit***

On May 16, 2022, VAALCO Gabon (Etame), Inc. entered into Facility Agreement by and among VAALCO, VAALCO Gabon, Glencore, the Law Debenture Trust Corporation P.L.C. and the Lenders, providing for a senior secured reserve-based revolving credit facility in an aggregate maximum principal amount of up to $50.0 million (the "Initial Total Commitment"). In addition, subject to certain conditions, the Borrower may agree with any Lender or other bank or financial institution to increase the total commitments available under the Facility by an aggregate amount not to exceed $50.0 million. Beginning October 1, 2023 and thereafter on April 1 and October 1 of each year during the term of the Facility, the Initial Total Commitment, as increased by any Additional Commitment, will be reduced by $6.25 million.

The Facility provides for determination of the borrowing base asset based on our proved producing reserves and a portion of our proved undeveloped reserves. The borrowing base is determined and re-determined by the Lenders on March 31 and September 30 of each year. Based on the redetermination performed during the year, there was no change in the borrowing base.

The Borrower's obligations under the Facility Agreement are guaranteed by Guarantors and secured by interests, rights, activities, assets, entitlements, and development in the Etame Marin Permit (Block G64-160) Field and any other assets which are approved by the Majority Lenders (as defined in the Facility Agreement).

Each loan under the Facility will bear interest at a rate equal to LIBOR plus a margin (the "Applicable Margin") of (i) 6.00% until the third anniversary of the Facility Agreement or (ii) 6.25% from the third anniversary of the Facility Agreement until the Final Maturity Date (defined below).

Pursuant to the Facility Agreement, we shall pay to Glencore for the account of each Lender a quarterly commitment fee equal to (i) 35% per annum of the Applicable Margin on the daily amount by which the lower of the total commitments and the borrowing base amount exceeds the amount of all outstanding utilizations under the Facility, plus (ii) 20% per annum of the Applicable Margin on the daily amount by which the total commitments exceed the borrowing base amount. The Borrower is also required to pay customary arrangement and security agent fees.

The Facility Agreement contains certain debt covenants, including that, as of the last day of each calendar quarter, (i) the ratio of Consolidated Total Net Debt to EBITDAX (as each term is defined in the Facility Agreement) for the trailing 12 months shall not exceed 3.0x and (ii) consolidated cash and cash equivalents shall not be lower than $10.0 million. As of December 31, 2022, our borrowing base was $50.0 million. The amount we are able to borrow with respect to the borrowing base is subject to compliance with the financial covenants and other provisions of the Facility Agreement. We were in compliance with all debt covenants at December 31, 2022. As of December 31, 2022, we had no outstanding borrowings under the facility. With regard to the requirement that we deliver our fiscal year 2022 annual financial statements to Glencore within 90 days of the end of each fiscal year, we have requested and received an extension until April 17, 2023.

The Facility will mature on the earlier of (i) the fifth anniversary of the date on which all conditions precedent to the first utilization of the Facility have been satisfied and (ii) the Reserve Tail Date (as defined in the Facility Agreement) (the "Final Maturity Date").

In connection with the Arrangement with TransGlobe in October 2022, prior to the effective time of the Arrangement, TransGlobe repaid in full all outstanding obligations and liabilities owed under TransGlobe's credit facility with ATB Financial, representing approximately C$4.1 million. On December 19, 2022, TransGlobe, as an indirect wholly-owned subsidiary of VAALCO, voluntarily delivered a notice of termination to ATB Financial relating to the ATB Facility. As of

December 31, 2022, no amounts were drawn on the revolving loan facility. On January 5, 2023, the ATB Facility was formally closed. Termination of the ATB Facility did not affect our $50.0 million senior secured reserve-based revolving credit facility with Glencore.

**Cash Requirements**

Our material cash requirements generally consist of finance leases, operating leases, purchase obligations, capital projects and 3D seismic processing, the Sasol Acquisition, the TransGlobe acquisition transaction costs, dividend payments, funding of our share buyback program, merged concession agreement, future lease payments and abandonment funding, each of which is discussed in further detail below.

*Sasol Acquisition* – As a result of completing the Sasol Acquisition on February 25, 2021, our obligations with respect to development activities in the Etame have increased based on the increase in our working interest in the Etame from 31.1 % at December 31, 2020, to 58.8%. As a result of the Sasol Acquisition, the net portion of production and costs relating to our Etame operations increased from 31.1% to 58.8%. Reserves, production and financial results for the interests acquired in the Sasol Acquisition have been included in VAALCO's results for periods after February 25, 2021. We expect that part of this increase will be offset by an increase in our operating cash flows based on our increased portion of the Etame production.

*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 November 2021, a new abandonment study was done and the estimate used for this purpose is approximately $81.3 million ($47.8 million, net to VAALCO) on an undiscounted basis. The new abandonment estimate has been presented to the Gabonese Directorate of Hydrocarbons as required by the PSC. Through December 31, 2022, $35.0 million ($20.6 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.

*Leases* - We are a party to several operating and financing lease arrangements, including operating leases for the corporate office, a drilling rig, rental of marine vessels and helicopters, warehouse and storage facilities, equipment and financing lease agreements for the FSO and generators used in the operations of the Etame Marin block and for equipment, offices and vehicles used in the operations of Canada and Egypt. The annual costs of these leases are significant to us. For further information see Note 14 to our consolidated financial statements.

*Merged Concession Agreement* - On January 20, 2022, prior to the consummation of the Arrangement, TransGlobe announced a fully executed Merged Concession Agreement with EGPC that merged the three existing Eastern Desert concessions with a 15-year primary term and improved economics. In advance of the Minister of Petroleum and Mineral Resources of the Arab Republic of Egypt (the "Minister") executing the Merged Concession Agreement, TransGlobe paid the first modernization payment of $15.0 million and signature bonus of $1.0 million as part of the conditions precedent to the official signing ceremony on January 19, 2022. On February 1, 2022, TransGlobe paid the second modernization payment of $10.0 million. In accordance with the Merged Concession, we agreed to substitute the 2023 payment and issue a $10.0 million credit against receivables owed from EGPC. We will make three further annual equalization payments of $10.0 million each beginning February 1, 2024, until February 1, 2026. We also have minimum financial work commitments of $50.0 million per each five-year period of the primary development term, commencing on February 1, 2020 (the "Merged Concession Effective Date"). As of December 31, 2022, the $50 million of financial work commitments had been delivered to EGPC.

*FSO Agreements* – On August 31, 2021, we and our Etame co-venturers approved the Bareboat Contract and Operating Agreement with World Carrier to replace the existing FPSO with a FSO unit at the Etame Marin block offshore Gabon. Pursuant to the Bareboat Charter, World Carrier will provide use of the *Teli* vessel to VAALCO Gabon for an initial eight-year term, subject to optional two successive one-year extensions. Pursuant to the Operating Agreement, VAALCO Gabon agreed to engage World Carrier for the purposes of maintaining and operating the FSO on its behalf in accordance with the specifications therein and to provide other services to VAALCO Gabon in connection with the operation and maintenance of the FSO. As consideration for the performance by World Carrier of the Operator Services, VAALCO Gabon agreed to pay a daily operating fee (to be paid monthly) beginning on the date of issuance of the Fit to Receive Certificate (as defined in the Operating Agreement) until the end of the term, with such term being the same as the term in the Bareboat Charter.

The FSO Agreements required a prepayment of $2 million gross ($1.2 million net to VAALCO) in 2021 and $5 million gross ($3.2 million net) in 2022 of which $6 million will be recovered against future rentals. In addition, VAALCO Gabon agreed to pay a daily hire rate at certain rates specified therein, with such hire rate being based on the year within the term.

In connection with the implementation of the FSO, we were required to incur certain Etame field configuration expenses in order to facilitate the FSO. Total field conversion expenses were $122 million gross ($77 million net to VAALCO).

The FPSO charter we were party to prior to the FSO installation was set to expire in September 2022, but on September 9, 2022, we signed an addendum to the FPSO contract which extended the use of the FPSO through October 4, 2022, and ratified certain decommissioning and demobilization items associated with exiting the contract. Pursuant to the addendum, VAALCO Gabon agreed to pay the charterer day rate of $150,000 from August 20, 2022 through October 4, 2022 and other demobilization fees totaling $15.3 million on a gross basis ($8.9 million net to VAALCO Gabon).

On October 19, 2022, we issued final acceptance certificate of the FSO. On December 4, 2022, the first lifting from the FSO was successfully completed at the same time the final remaining volumes from the FPSO were removed.

*BWE Consortium* – On October 11, 2021, we announced our entry into a consortium with BW Energy and Panoro Energy and that the BWE Consortium has been provisionally awarded two blocks in the 12th Offshore Licensing Round in Gabon. The award is subject to concluding the terms of the PSC with the Gabonese government. BW Energy will be the operator with a 37.5% working interest. We will have a 37.5% working interest and Panoro Energy will have a 25% working interest as non-operating joint owners. The two blocks, G12-13 and H12-13, are adjacent to our Etame PSC, as well as BW Energy and Panoro's Dussafu PSC offshore Southern Gabon, and cover an area of 2,989 square kilometers and 1,929 square kilometers, respectively. The two blocks will be held by the BWE Consortium and the PSCs over the blocks 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. 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.

*Drilling Program* – We commenced the 2021/2022 drilling campaign in December 2021 with the drilling of the Etame 8H-ST development well. In February 2022 we completed the drilling of the Etame 8H-ST well and moved the drilling rig to the Avouma platform to drill the Avouma 3H-ST development well, which targeted the Gamba reservoir. The initial flow rate of the ETAME 8H-ST well was 5,000 BOPD, 2,560 BOPD net to VAALCO's 58.8% working interest in 2022. The 8H-ST was shut in due to Hydrogen sulfide that arose during the drilling process, but a side track was performed to rectify this and resume production. In April 2022, the Avouma 3H-ST well was completed and brought online with an initial production rate of approximately 3,100 gross BOPD, 1,589 BOPD net to VAALCO's 58.8% working interest in 2022.

In July 2022 we completed the South Tchibala 1HB-ST well on the Avouma platform, targeting the Gamba reservoir and also testing the Dentale formation. The section of the Gamba sand encountered was not economically viable to complete in this wellbore. However, we did discover two potential zones, the Dentale D1 and Dentale D9 zones for development. The well was completed in the Dentale D1 formation and brought online in July with an initial production rate of approximately 293-390 gross BOPD, 150-200 BOPD net to VAALCO's 58.8% working interest in 2022. The Dentale D9 well is temporarily shut-in, however; we plan to evaluate and recomplete the D9 zone during the next drilling campaign.

Following the completion of the South Tchibala 1HB-ST well, the rig was mobilized to the Southeast Etame North Tchibala Platform to drill the North Tchibala 2H-ST well, targeting the Dentale formation, which is productive in this area of the Etame license. This mobilization was delayed by two weeks due to weather and the rig began operations on the well in late July. After setting up the equipment and completing operations to re-enter the well, VAALCO began drilling the North Tchibala 2H-ST well on August 8, 2022. The North Tchibala 2H-ST well was brought online in early November and flowed at a low, controlled rate to allow for cleanup and to minimize negative impact to the completion. Through end of January, the well flowed, with temporary interruptions for operational activity and shut-ins for pressure build up analysis. During this time, the well produced approximately 18,500 gross barrels of oil, or about 250 gross BOPD and recovered about 36% of injected completion fluid. Cleanup is continuing and pressure transient analysis indicates that both completed zones may be contributing. The well is naturally flowing with no water production and stable reservoir pressure indicating minimal depletion.

We recently utilized the rig to perform a workover on the North Tchibala 1H well due to a safety valve in the well that required replacement. With the rig already on site it was easier and more economic to utilize the rig to complete the workover following the completion of the North Tchibala 2H-ST well. The final well operation planned for the rig was another workover, the South East Etame 4-H well, which restored production to 1,000 and 1,500 gross BOPD upon completion. This well went offline in early September as a result of an upper ESP failure and we were unable to restart the upper ESP or the lower ESP to restore production. Utilizing the rig for the workovers has optimized the total cost of the 2021/2022 drilling campaign at Etame.

After the execution of the workovers the drilling rig was released on November 17, 2022.

We estimate the cost of the current 2021/2022 drilling program with four wells and two workovers to be $180 million, or $114 million, net to VAALCO's participating interest. For 2022, we incurred approximately $148 million, or about $94 million net to VAALCO's participating interest.

*TransGlobe Acquisition* – On October 13, 2022, the Company and AcquireCo completed the business combination with TransGlobe. At the effective time of the Arrangement and pursuant to the Arrangement Agreement, each common share of TransGlobe issued and outstanding immediately prior to the effective time of the Arrangement was converted into the right to receive 0.6727 of a share of VAALCO common stock. The total number of VAALCO shares issued to TransGlobe's shareholders was approximately 49.3 million. In addition, we incurred $14.6 million of transaction costs associated with the acquisition agreement.

*Dividend Policy* – On February 14, 2023, we announced that our board of directors adopted of a quarterly cash dividend policy of an expected $0.0625 per common share per quarter, commencing 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.

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.

*Share Buyback Program* – On November 1, 2022, we announced that our board of directors formally ratified and approved the share buyback program that was announced on August 8, 2022 in conjunction with our business combination with TransGlobe. The board of directors also directed management to implement 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 Exchange Act. The 10b5-1 Plan provides for an aggregate purchase of currently outstanding common stock up to $30 million over 20 months. Payment for shares repurchased under the share buyback program will be funded using our cash on hand and cash flow from operations. As of December 31, 2022, approximately $27.0 million remained available for repurchase under current authorizations.

**Trends and Uncertainties**

*COVID-19 Pandemic* – While crude oil prices have recently been at the highest levels seen in recent years, the continued spread of COVID-19, including vaccine-resistant strains, or deterioration in crude oil, natural gas and NGLs prices could result in additional adverse impacts on our results of operations, cash flows and financial position, including asset impairments. The health of our employees, contractors and vendors, and our ability to meet staffing needs in our operations and certain critical functions cannot be predicted and is vital to our operations. We are unable to predict the extent of the impact that the continuing spread of COVID-19 may have on our ability to continue to conduct our operations.

Further, the impacts of a potential worsening of global economic conditions and the continued disruptions to, and volatility in, the credit and financial markets as well as other unanticipated consequences remain unknown. In addition, we cannot predict the impact that COVID-19 will have on our customers, vendors and contractors; however, any material effect on these parties could adversely impact our business. The situation surrounding COVID-19 remains fluid and unpredictable, and we are actively managing our response and assessing potential impacts to our financial position and operating results, as well as any adverse developments that could impact our business.

*War with Ukraine and Other Market Forces* – The outbreak of armed conflict between Russia and Ukraine in February 2022 and the subsequent sanctions imposed on the Russian Federation has, and may continue to have, a destabilizing effect on the European continent and the global oil and natural gas markets. The ongoing conflict has caused, and could continue to intensify, volatility in oil and natural gas prices, and the extent and duration of the military action, sanctions and resulting market disruptions could be significant and could potentially have a substantial negative impact on the global economy and/or our business for an unknown period of time.

Further, the slowdown in the Chinese economy is negatively impacting the global market and the global supply chain problems may have a material adverse impact on our financial results and business operations, including our timing and ability to complete future drilling campaigns and other efforts required to advance the development of our crude oil, natural gas and NGLs properties.

For example, shortly after the outbreak of the conflict through the year ended December 31, 2022 and on-going into 2023, we noticed that the lead times associated with obtaining materials to support our operations and drilling activities has lengthened, leading to delays and, in most cases, prices for materials have increased. Management believes the ongoing war between Russia and Ukraine and its related impact on the global economy are causing supply chain issues and energy concerns in parts of the global economy. In addition, increased inflation, higher interest rates and current turmoil in certain governments are impacting the global supply chain market.

*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 prices, a decrease in demand for crude oil and future production cuts by OPEC+. In July 2021, OPEC+ agreed to increase production beginning in August 2021 to phase out a portion of the prior production cuts by September 2022. However, as a result of the recent decline in oil prices, on October 5, 2022, OPEC+ announced plans to reduce overall oil production by 2 MMBbls per day starting November 2022. To date, we have not received any mandate to reduce our current oil production from the Etame Marin block as a result of the OPEC+ initiative. Brent crude prices were approximately $82.82 per barrel as of December 31, 2022.

*ESG and Climate Change Effects* – ESG matters continue to attract considerable public and scientific attention. In particular, we expect continued regulatory attention on climate change issues and emissions of GHGs, including methane (a primary component of natural gas) and carbon dioxide (a byproduct of crude oil, natural gas and NGLs combustion). This increased attention to climate change and environmental conservation may result in demand shifts away from crude oil, natural gas and NGLs products to alternative forms of energy, higher regulatory and compliance costs, additional governmental investigations and private litigation against us. 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, 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 investors' investment and voting decisions, which for some investors may lead to less favorable sentiment towards carbon assets and diversion of investment to other industries. Consistent with the increased attention on ESG matters and climate change, we have prioritized and are committed to responsible environmental practices by monitoring our adherence to ESG standards, including the reduction of our carbon footprint and measurement of GHG emissions. ESG is important to us, and we are in the process of developing a multi-year plan to establish and document our ESG base currently and developing a systematic plan to monitor and improve matters related to ESG and climate change going forward. Additional ESG regulation will result in additional expenses and may result in less revenue due to the cost of compliance.

VAALCO recognizes climate change as a risk to the business and industry.

It also recognizes the potential for the business to decarbonize its operations, reduce operating costs, and deliver more sustainably produced oil and gas products, whilst serving its developing host nation that still require improved energy access and supply, and the economic benefits the industry generates, directly and indirectly.

The Company acknowledges the requirement to share information with stakeholders regarding its response to climate-related risks and opportunities.

For the past three years the Company has matured its reporting in line with the recommendations of the Task force on Climate-related Financial Disclosures ("TCFD"), which is recognized as the global standard in climate-related reporting. The full TCFD report will be included within the 2022 ESG Report (rather than in this Annual Report on Form 10-K or in the annual report which will be published in connection with the annual meeting), as the ESG Report details with environmental, social and governance matters which the TCFD report forms an important part of. The 2022 ESG Report will be made available on the Company's website.

In summary the Company considers itself consistent with both the Governance and Strategy pillars and the recommendations therein. It does not consider itself consistent with Risk Management nor Metrics and Targets, but has made meaningful progress against certain of the underlying recommendations and provides statements of intent to address these recommendations during 2023. For further detail see the table below.

| | | |
|---|---|---|
| Governance | Describe the Board's oversight of climate-related risks and opportunities<br><br>Describe management's role in assessing and managing climate-related risks and opportunities. | The Board is actively engaged in understanding the climate-related risks relevant to the business.<br>The Board supported the establishment of the decarbonization program and receives regular updates on progress.<br>At each Board meeting, the ESG manager reports emissions performance and progress within decarbonization program.<br>Management receives periodic updates from the ESG Engineer and Buchanan ESG relating to climate-related matters.<br>The formalized management of climate-related matters, and specifically VAALCO's efforts to manage its emissions profile, is delivered through its decarbonization working group and steering group, for identification of emissions reduction projects and subsequent approval respectively.<br>The Company considers its approach to governance consistent with the recommendations. |
| Strategy | Describe the climate-related risks and opportunities the organization has identified over the short, medium and long term.<br><br>Describe the impact of climate-related risks and opportunities on the organization's businesses, strategy, and financial planning.<br><br>Describe the resilience of the organization's strategy, taking into consideration different climate-related scenarios, including a 2°C or lower scenario | The Company has identified transitional and physical risks and opportunities identified over the short (<2 years), medium (2 to 10 years) and long term (>10 years) within its ESG Report 2022.<br>The company has indicated the potential impact of these risks and associated mitigations.<br><br>The Company continues to mature its approach to factoring in climate-related risks and opportunities into its strategy and financial planning. This also includes its diligence through M&A activity.<br>This year, the business conducted scenario analysis using the IEA's Net Zero Emissions (NZE), Announced Pledges Scenario (APS) and Stated Policies Scenario (STEPS), the details and findings for which are enclosed in the ESG Report.<br>The Company considers its approach to Strategy consistent with the recommendations. |
| Risk Management | Describe the organization's processes for identifying and assessing climate-related risks.<br><br>Describe the organization's processes for managing climate-related risks.<br><br>Describe how processes for identifying, assessing, and managing climate-related risks are integrated into the organization's overall risk management. | The Company has a defined risk management process for identifying and assessing risk, which incorporates climate-related risks. Detail to this process can be found within the ESG Report.<br>Whilst in development through the decarbonization program, the Company considers its processes for managing climate-related risk to be inconsistent with the recommendations.<br>During 2023, the Company will conduct a review of its risk management processes, particularly in view of its enlarged portfolio. |
| Metrics and Targets | Disclose the metrics used by the organization to assess climate-related risks and opportunities in line with its strategy and risk management process.<br>Disclose Scope 1, Scope 2 and, if appropriate Scope 3 greenhouse gas (GHG) emissions and the related risks.<br><br>Describe the targets used by the organization to manage climate-related risks and opportunities and performance against targets | The Company reports its scope 1 and 2 emissions but has not yet set any targets.<br><br>The Company considers its approach to metrics and targets inconsistent with the recommendations and, through its decarbonization program, is seeking to set interim reduction targets for its GHG emissions. |

**Hedging**

We seek to mitigate the impact of volatility in crude oil prices through hedging.

The following are the hedges outstanding at December 31, 2022:

| Settlement Period | Type of Contract | Index | Average Monthly Volumes (Bbls) | Weighted Average Put Price (per Bbl) | Weighted Average Call Price (per Bbl) |
|---|---|---|---|---|---|
| January 2023 to March 2023 | Collars | Dated Brent | 101,000 | $ 65.00 | $ 120.00 |

The following are the additional hedges entered into in 2023:

| Settlement Period | Type of Contract | Index | Average Monthly Volumes (Bbls) | Weighted Average Put Price (per Bbl) | Weighted Average Call Price (per Bbl) |
|---|---|---|---|---|---|
| April 2023 to June 2023 | Collars | Dated Brent | 95,500 | $ 65.00 | $ 100.00 |
| July 2023 to September 2023 | Collars | Dated Brent | 95,500 | $ 65.00 | $ 96.00 |

## RESULTS OF OPERATIONS

### Year Ended December 31, 2022 Compared to Year Ended December 31, 2021

We reported net income for the year ended December 31, 2022 of $51.9 million, compared to a net income of $81.8 million for the year ended December 31, 2021. The year-over-year decrease in earnings was mainly due to increases in depreciation, depletion and amortization expense, production expenses and changes in taxes from a benefit in 2021 to an expense in 2022. Further discussion of results by significant line item follows.

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2022** | **2021** | **Increase/(Decrease)** |
| | *(in thousands except per Boe information)* | | |
| Net crude oil, natural gas, and NGLs sales volume (MBoe) | **3,677** | 2,711 | 966 |
| Average crude oil, natural gas and NGLs sales price (per Boe) | **$ 94.77** | $ 70.66 | $ 24.11 |
| Net crude oil, natural gas, and NGLs revenue | **$ 354,326** | $ 199,075 | $ 155,251 |
| Operating costs and expenses: | | | |
| Production expense | **112,661** | 81,255 | 31,406 |
| FPSO demobilization | **8,867** | — | 8,867 |
| Exploration expense | **258** | 1,579 | (1,321) |
| Depreciation, depletion and amortization | **48,143** | 21,060 | 27,083 |
| General and administrative expense | **10,077** | 14,766 | (4,689) |
| Bad debt expense | **3,082** | 875 | 2,207 |
| Total operating costs and expenses | **183,088** | 119,535 | 63,553 |
| Other operating (expense) income, net | **38** | (440) | 478 |
| Operating income | **$ 171,276** | $ 79,100 | $ 92,176 |

The revenue changes between the years ended December 31, 2022 and 2021 identified as related to changes in price or volume are shown in the table below:

| ***(in thousands)*** | |
|---|---|
| Price [(1)] | $ 94,674 |
| Volume | 14,698 |
| Other | (1,672) |
| Change in revenue from Gabon | $ 107,700 |
| Net revenue from Egypt | $ 37,710 |
| Net revenue from Canada | 9,841 |
| Total net revenue | $ 155,251 |

[(1)] The price in the table above excludes revenues attributed to carried interests.

The table below shows net production, sales volumes and realized prices for both years.

| | Year Ended December 31, | |
|---|---|---|
| | 2022 | 2021 |
| Net crude oil, natural gas and NGLs production (MBoe) | 3,729 | 2,405 |
| Net crude oil, natural gas and NGLs sales (MBoe) | 3,677 | 2,711 |
| | | |
| Average realized crude oil, natural gas and NGLs price ($/Boe) | $ 94.77 | $ 70.66 |
| Average Dated Brent spot price* ($/Bbl) | $ 100.93 | $ 70.86 |

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

*Crude oil, natural gas and NGL revenues* increased $155.3 million, or approximately 78.0%, during the year ended December 31, 2022 compared to the same period of 2021. The total barrels lifted in Gabon for the year ended December 31, 2022 was more than the barrels lifted during the same period in 2021, mainly due to 2021/2022 drilling campaign partially offset by natural declines in production. In addition, the per barrel price received during 2022 was $32.43 higher than the price received in 2021. 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. We made 11 liftings in Gabon during both years ended December 31, 2022, and December 31, 2021, respectively. Our share of crude oil inventory, excluding royalty barrels, was approximately 76,274 and 75,680 barrels at December 31, 2022 and 2021, respectively. Crude oil, natural gas and NGLs sales also increased due to the TransGlobe acquisition on October 13, 2022 with sales from both Egypt and Canada being recorded from the acquisition date through December 31. 2022 and contributing $47.6 million of revenue in 2022.

*Production expenses* increased $31.4 million, or approximately 38.7%, in the year ended December 31, 2022 compared to the same period of 2021. $17.5 million of the increase is attributable to our Gabon operations with higher marine fuel and personnel costs as a result of inflation increases. In addition, we incurred $13.9 million of production expense related to our Egypt and Canadian operations from the date of the acquisition through December 31, 2022. On a per barrel NRI basis, production expense, excluding workover expense and stock compensation expense, for the year ended December 31, 2022, increased to $29.33 per barrel from $26.77 per barrel for the year ended December 31, 2021, primarily as a result of higher marine, fuel and personnel costs. While we have not experienced any significant operational disruptions associated with the current worldwide COVID-19 pandemic, we have incurred approximately $1.8 million of COVID-19 related costs, net to VAALCO, for the year ended December 31, 2022. For the same period in 2021, we incurred $2.9 million, net to VAALCO, higher costs related to the proactive measures taken in response to the pandemic.

*FPSO demobilization costs* for the year ended December 31, 2022 were $8.9 million. These costs were incurred to retire the FPSO as we transitioned the Etame block to the FSO. No similar expenses were incurred during the same period in 2021.

*Exploration expenses* decreased $1.3 million or approximately 83.7%, in the year ended December 31, 2022 compared to the same period of 2021. The decrease is due to incurring minimal amounts for seismic processing costs for the year ended December 31, 2022 compared to the same period in 2021 when we were processing the seismic data acquired in 2020.

*Depreciation, depletion and amortization* increased $27.1 million, or approximately 128.6%, in the year ended December 31, 2022 compared to the same period of 2021. $13.7 million of the change is attributable to our Gabon operations while $13.4 million of the change is due to the depletions associated with the TransGlobe acquisition from the date of acquisition, October 13, 2022, through December 31, 2022. The higher depletion associated with the Gabon operations is due to higher depletable costs associated with the 2021/2022 drilling campaign.

*General and administrative expenses* decreased $4.7 million, or approximately 31.8% in the year ended December 31, 2022 compared to $14.8 million in the same period of 2021. The decrease in expense was primarily related to lower corporate salary and wages, lower legal fees, lower compensation related to liability awards and higher allocations of corporate expenses in 2022 (collectively $10.2 million) partially offset by higher audit and professional fees, higher stock based compensation related to equity awards and higher professional fees and other fees (collectively $5.2 million). In addition, we incurred $0.4 million of general and administrative expenses associated with the TransGlobe acquisition from the acquisition date, October 13, 2022, through December 31, 2022

*Bad debt (recovery) expense and other* reflected bad debt expense associated with the VAT allowance for the year ended December 31, 2022. Bad debt expense increased $2.2 million, or approximately 252.2% in the year ended December 31, 2022 compared to the same period of 2021 as a result of increased spending as a result of the 2021/2022 drilling campaign partially offset by $0.5 million, net to VAALCO, in VAT payments received.

*Other operating income (expense), net* increased $0.5 million, or approximately 108.6%, in the year ended December 31, 2022 compared to the same period of 2021. For the year ended December 31, 2021 other operating income (expense) is primarily comprised of the difference between the fair value of the contingent consideration paid to Sasol in April 2021 of $5.0 million, and the fair value of the contingent consideration on the closing date of the Sasol Acquisition of $4.6 million.

*Derivative instruments gain (loss), net* is attributable to our commodity instruments as discussed in Note 10 to the consolidated financial statements. Derivative losses increased $15.0 million to a loss of $37.8 million loss for the year ended December 31, 2022 from a loss of $22.8 million for the year ended December 31, 2021. We used swaps to hedge our production through the third quarter of 2022 and then transitioned to costless collars beginning in the fourth quarter of 2022. Every quarter in 2021 and continuing through the third quarter of 2022 Dated Brent crude oil prices increased. Since VAALCO owes the counterparty for any Dated Brent price over the initial per barrel value, we continued to incur losses associated our commodity swap derivatives. Our current commodity derivative instruments cover a portion of our production through June 2023.

*Interest (expense) income, net* increased $2.0 million to an expense of $2.0 million for the year ended December 31, 2022 from expense of $0.0 million during the same period in 2021. Net interest expense for the year ended December 31, 2022, includes commitment fees incurred on the Facility, amortization of debt issue costs related to the VAALCO RBL Facility and interest associated with our finance leases partially offset by interest income.

*Other (expense) income, net* decreased $11.5 million to expense of $8.0 million for the year ended December 31, 2022 from income of $3.5 million for the year ended December 31, 2021. Other (expense) income, net normally consists of foreign currency losses as discussed in Note 2 to the consolidated financial statements. However, for the year ended December 31, 2022, other (expense) income, net, also included $14.6 million of transaction costs associated with the Arrangement with TransGlobe, $2.7 million of foreign exchange losses associated with the TransGlobe activity from October 13, through December 31, 2022 partially offset by a bargain purchase gain of $10.8 million associated with the acquisition of TransGlobe. Other (expense) income, net, was primarily attributable to $5.2 million for the bargain purchase gain offset by $1.0 million for an acquisition success fee and foreign currency losses for the year ended December 31, 2021.

*Income tax expense (benefit)* for the year ended December 31, 2022 was an expense of $71.4 million. This is comprised of $26.6 million of current tax provision and a deferred tax provision of $44.8 million. Income tax expense for the year ended December 31, 2021 was a benefit of $22.1 million. This is comprised of $42.4 million of deferred tax benefit and a current tax provision of $20.3 million. The current tax provision in both periods is primarily attributable to our operations in Gabon, Egypt and Canada and is higher in 2022 than income tax for the comparable 2021 period as a result of higher revenues. See Note 8 to the Consolidated Financial Statements for further discussion.

*Income (loss) from discontinued operations, net of tax* for the year ended December 31, 2022 was attributable to our Angola and Yemen segments as discussed further in Note 4 to the Financial Statements. For the year ended December 31, 2021, loss from discontinued operations was attributable to our Angola segment. The loss from discontinued operations for the year ended and December 31, 2022 and December 31, 2021, respectively, was related to Angola and Yemen administration costs.

## 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 Note 2 to the Consolidated Financial Statements for our accounting policy elections.

*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, 2022, we had deferred tax assets of $99.6 million primarily attributable to Canada, Gabon and U.S. basis differences in fixed assets, foreign tax credit carryforwards, and U.S. and foreign net operating loss carryforwards. A valuation allowance of $47.6 million has been established against the deferred tax assets as of December 31, 2022, 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 Note 8 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 quality 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 our independent qualified reserves engineers, NSAI for Gabon and Equatorial Guinea, while GLJ evaluates our Egyptian and Canadian reserves.

Our board of directors has established the Technical and Reserves ("T&R") 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 T&R 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 T&R Committee and senior executives 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 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. The undiscounted estimated future net cash flows used in the impairment evaluations at each quarter end are based upon the most recently prepared independent reserve engineers' report adjusted to use forecasted prices from the forward strip price curves near each quarter end and adjusted as necessary for drilling and production results. For further discussion, see Note 9 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 block in Gabon and to Block P in Equatorial Guinea. In connection with the TransGlobe acquisition as discussed under Note 4 to the Consolidated Financial Statements, reserves in Egypt and Canada were also attributed to undeveloped properties and leasehold costs.

***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 development 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 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. See Note 4 to the Consolidated Financial Statements under “Acquisitions and dispositions” for further discussion.

## NEW ACCOUNTING STANDARDS

See Note 3 to the Consolidated Financial Statements.

## Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risk, 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, 2022, we had net monetary assets of $20.4 million (XAF 12,491.50 million) denominated in XAF. A 10% weakening of the CFA relative to the U.S. dollar would have a $1.8 million reduction in the value of these net assets. For the year ended December 31, 2022, we had expenditures of approximately $39.0 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 decrease net earnings for the year ended December 31, 2022 by approximately $0.9 million. Conversely, a 10% decrease in the value of the Canadian dollar against the US dollar would increase net earnings for the year ended December 31, 2022 by approximately $0.9 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, 2022, we estimate that a 10% increase in the value of the Egyptian pound against the US dollar would increase net earnings for the year ended December 31, 2022 by approximately $0.5 million. Conversely, a 10% decrease in the value of the Egyptian pound against the US dollar would decrease net earnings for the year ended December 31, 2022 by approximately $0.5 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 resumption 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. If crude oil sales were to remain constant at the most recent annual sales volumes of 3,677 MBoe, a $5 per Bbl decrease in crude oil price would be expected to cause a $18.4 million decrease per year in revenues and operating income (loss) and a $16.5 million decrease per year in net income (loss).

As of December 31, 2022, we had unexpired derivative instruments outstanding covering approximately 304 MBbls of production through March 2023. In February 2023, we added costless collars covering 286 MBbls covering a portion of our production from April 2023 through June 2023. During the years ended December 31, 2022 and 2021, we had derivative instruments outstanding. These instruments were intended to be an economic hedge against declines in crude oil prices; however, they were not designated as hedges for accounting purposes. See "*Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation*s *– Derivative instruments and hedging activities*" above.

***Interest Rate Risk***

At both December 31, 2022 and on the filing date of this Annual Report, we had a zero balance on our Facility. Loans under the Facility will bear interest at a rate equal to LIBOR plus the Applicable Margin of (i) 6.00% until the third anniversary of the Facility Agreement or (ii) 6.25% from the third anniversary of the Facility Agreement until the Final Maturity Date. Any increases in these interest rates can have an adverse impact on our results of operations and cash flows. For additional information on the Facility Agreements terms and conditions, see "*Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity—RBL Facility Agreement and Available Credit*" above.

## 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

### 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 the Chief Executive Officer and Chief Financial Officer, 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 principal executive officer and principal financial officer, 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 principal executive officer and principal financial officer have concluded that, due to the material weaknesses described below, the Company's disclosure controls and procedures were not effective as of December 31, 2022 at the reasonable assurance level.

## MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management, including our Chief Executive Officer and our Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Under the supervision and with the participation of management, including our principal executive and principal financial officers, we conducted an evaluation of the effectiveness of our internal control over financial reporting using the criteria set forth in the Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). On October 13, 2022, the Company completed the acquisition of TransGlobe (see Note 4 to the Consolidated Financial Statements), which operated under its own set of internal controls. As permitted by the SEC Staff interpretive guidance for newly acquired businesses, the Company's management excluded TransGlobe from the evaluation of internal control over financial reporting as of December 31, 2022. Since completion of the acquisition, the Company transitioned certain TransGlobe processes to the Company's internal control processes and added other internal controls over significant processes specific to the acquisition and to post-acquisition activities, including internal controls associated with the valuation of certain assets acquired and liabilities assumed in the acquisition. The Company will continue the process of integrating internal controls over financial reporting for TransGlobe and plans to incorporate TransGlobe in the evaluation of internal controls over financial reporting beginning in the second quarter of 2023. TransGlobe represented 48% of the Company's consolidated total assets as of December 31, 2022, while its revenues comprised 13% of the Company's consolidated sales and its net income comprised 19% of the Company's net income for the year ended December 31, 2022.

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. 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. Based on the evaluation and due to the material weaknesses described below, our management concluded that, the Company's internal control over financial reporting was not effective as of December 31, 2022. A material weakness in internal controls 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 our annual or interim financial statements will not be prevented or detected on a timely basis.

We have identified the following material weaknesses:

*Accounting for Leases* We did not design and maintain effective controls over the change in method of accounting for leases Accounting Standard Update No. 2016-02, Leases (ASC 842). The Company's controls over the application of the proper accounting treatment for leases related to discount rates used and the identification and communication when a lease was modified were not effective, as the discount rate and a modification were not properly reflected in the historical accounting analysis. This material weakness could have resulted in improper balances related to lease assets and lease liabilities in our fiscal 2022 consolidated financial statements.

*Complex Accounting for Business Combinations* We did not design and maintain effective controls over the accounting for our acquisition with TransGlobe, including a lack of sufficient precision in the performance of reviews of the analyses supporting the purchase price allocation accounting and other acquisition related entries with adequate documentation to provide sufficient evidence of operating effectiveness of associated management review controls. This material weakness could have resulted in material adjustments to the initial purchase price recorded in our fiscal 2022 consolidated financial statements.

*Financial Reporting and Consolidation* We did not design and maintain an effective controls over the preparation of consolidated financial statements and consolidation of our subsidiaries as it relates to our Canadian and Egyptian operations, which were acquired as part of the TransGlobe acquisition. We did not provide sufficient and appropriate documentation related to demonstrating adequate review of the combined company consolidation. This material weakness could have resulted in material adjustments to the consolidated financial statements of the combined company in fiscal 2022.

*Accounting for Income Taxes* We did not design and maintain effective controls over the accounting for income taxes principally related to review over tax workpapers. This material weakness resulted in adjustments to the current income taxes, and deferred taxes, in our fiscal year 2022 consolidated financial statements.

After giving full consideration to these material weaknesses, and the additional analyses and other procedures that we performed to ensure that our consolidated financial statements included in this Annual Report were prepared in accordance with U.S. GAAP, our management has concluded that our consolidated financial statements present fairly, in all material respects, our financial position, results of operations and cash flows for the periods disclosed in conformity with US GAAP.

**Remediation Process**

Following the identification of the material weaknesses described above, and with the oversight of the Audit Committee, we have commenced a process to remediate the underlying causes of the material weaknesses described above, enhance the control environment and strengthen our internal control over financial reporting. The steps that have been taken or that the Company intends to take with respect to remediation are as follows:

- We plan to devote additional resources towards engaging personnel to acquire and enhance relevant public company financial reporting and accounting skillsets, with a focus in the areas identified above.
- We plan to redesign our control framework involving identification and communication concerning certain accounting and business operations procedures and controls to achieve, accurate and timely financial accounting, reporting and necessary disclosures.
- We plan to enhance adequate documentary evidence for relevant management review controls over certain business processes including precision of review and evidence of review procedures performed to demonstrate effective operation of such controls.

As we continue to evaluate and work to improve our internal control over financial reporting, we may take additional measures to address control deficiencies, or we may modify certain of the remediation measures described above. The material weaknesses will not be considered remediated until the applicable controls operate for a sufficient period of time and management has concluded, through testing, that these controls are operating effectively.

Our internal control over financial reporting as of December 31, 2022 has been audited by BDO USA, LLP, an independent registered public accounting firm, as stated in their report which is included in Item 8 of this Annual Report. BDO USA, 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, there have been no changes in our internal control over financial reporting during the three months ended December 31, 2022 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

**Item 9B. Other Information**

None.

### 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 the proxy statement for our 2023 annual meeting, which will be filed with the SEC within 120 days of December 31, 2022, and that is incorporated herein by reference.

### Item 11. Executive Compensation

Information required by this item will be included in the proxy statement for our 2023 annual meeting, which will be filed with the SEC within 120 days of December 31, 2022, 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 the proxy statement for our 2023 annual meeting, which will be filed with the SEC within 120 days of December 31, 2022, and which is incorporated herein by reference.

The following table provides information as of December 31, 2022 regarding the number of shares of common stock that may be issued under our compensation plans. Please refer to Note 17 to the 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 | 830,388 | $ 2.97 | 3,870,496 |
| Total | 830,388 | $ 2.97 | 3,870,496 |

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

Information required by this item will be included in the proxy statement for our 2023 annual meeting, which will be filed with the SEC within 120 days of December 31, 2022, and that is incorporated herein by reference.

### Item 14. Principal Accountant Fees and Services

Information required by this item will be included in the proxy statement for our 2023 annual meeting, which will be filed with the SEC within 120 days of December 31, 2022, 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 | |
| Report of Independent Registered Public Accounting Firm (BDO USA, LLP; Houston, Texas; PCAOB ID No. 243) | F-1 |
| Report of Independent Registered Public Accounting Firm Over Internal Controls over Financial Reporting (BDO USA, LLP; Houston, Texas; PCAOB ID No. 243) | F-2 |
| Consolidated Balance Sheets as of December 31, 2022 and 2021 | F-3 |
| Consolidated Statements of Operations and Comprehensive Income (Loss) for the Years Ended December 31, 2022, 2021 and 2020 | F-4 |
| Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2022, 2021 and 2020 | F-5 |
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(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). |
| 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 13, 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 | Description of securities (filed as Exhibit 4.1 to the Company's Current Report on Form 10-K filed on March 9, 2020, and incorporated herein by reference). |
| 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). |

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|---|---|
| 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 Appreciate 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* | 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). |
| 10.19* | 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). |
| 10.20* | 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). |
| 10.21* | 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). |
| 10.21.1* | 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). |
| 10.21.2*(a) | Amendment No. 2 to Employment Agreement, by and between VAALCO Energy, Inc. and George Maxwell, effective as of November 23, 2022. |

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|---|---|
| 10.22* | Employment Agreement, dated as of May 25, 2021, by and between VAALCO Energy, Inc. and Michael Silver (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K filed on May 28, 2021, and incorporated herein by reference). |
| 10.22.1* | First Amendment to Employment Agreement, dated as of August 30, 2022, by and between VAALCO Energy, Inc. and Michael Silver (filed as Exhibit 10.1 to the Company's Current Report on form 10-Q filed on November 8th, 2022, 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*(a) | Amendment No. 2 to Employment Agreement, effective as of November 23, 2022, by and between VAALCO Energy, Inc. and Ronald Bain. |
| 10.24*(a) | TransGlobe Energy Corporation Amended and Restated Deferred Share Unit Plan. |
| 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(a) | 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. |
| 10.25.2(a) | Second Amendment to Bareboat Charter, by and between VAALCO Gabon SA and Ocean Cloud Navigation Inc., dated as of March 22, 2023. |
| 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 by reference herein). |
| 10.26.1(a) | 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. |
| 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 by reference herein). |
| 10.27.1(a) | 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. |
| 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 by reference herein) |
| 10.28.1(a) | 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. |
| 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 by reference herein) |
| 10.30 | Facility Agreement, by and among VAALCO Energy, Inc., VAALCO Gabon (Etame), Inc., VAALCO Gabon, SA, Glencore Energy UK Ltd., the Law Debenture Trust Corporation P.L.C., and the other financial institutions named therein, dated May 16, 2022 (filed as Exhibit 10.1 to the Company’s Quarterly Report on Form 10-Q filed on August 10, 2022, and incorporated herein by reference). |
| 10.31 | Crude Oil Sale and Marketing Agreement, by and between VAAALCO 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). |
| 10.32*(a) | Separation Agreement, by and between VAALCO Energy, Inc. and David DesAutels, dated as of March 8, 2023 |
| 10.33*(a) | Consulting Agreement between VAALCO Energy and David DesAutels, dated as of March 8, 2023. |

| | |
|---|---|
| 21.1(a) | List of subsidiaries of the Company. |
| 23.1(a) | Consent of BDO USA, LLP. |
| 23.2(a) | Consent of Netherland, Sewell & Associates, Inc. — Independent Petroleum Engineers. |
| 23.3(a) | Consent of GLJ Ltd. — 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. |
| 99.1(a) | Report of Netherland, Sewell & Associates, Inc. (International Properties). |
| 99.2(a) | Report of GLJ Ltd. |
| 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

### 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 April 6, 2023

**Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on the 6th day of April 2023, by the following persons on behalf of the registrant and in the capacities indicated.**

| Signature | Title |
|---|---|
| By: /s/ George Maxwell<br>George Maxwell | Chief Executive Officer (Principal Executive Officer) and Director |
| By: /s/ Ron Bain<br>Ron Bain | Chief Financial Officer (Principal Financial Officer) |
| By: /s/ Jason Doornik<br>Jason Doornik | Chief Accounting Officer (Principal Accounting Officer) |
| By: /s/ Andrew L. Fawthrop<br>Andrew L. Fawthrop | Chairman of the Board and Director |
| By: /s/ Catherine L. Stubbs<br>Catherine L. Stubbs | Director |
| By: /s/ Fabrice Nze-Bekale<br>Fabrice Nze-Bekale | Director |
| By: /s/ David Cook<br>David Cook | Director |
| By: /s/ Edward LaFehr<br>Edward LaFehr | Director |
| By: /s/ Timothy Marchant<br>Timothy Marchant | Director |

## Report of Independent Registered Public Accounting Firm

Shareholders and Board of Directors
VAALCO Energy, Inc.
Houston, Texas

**Opinion on the Consolidated Financial Statements**

We have audited the accompanying consolidated balance sheets of VAALCO Energy, Inc. (the "Company") as of December 31, 2022 and 2021, the related consolidated statements of operations and comprehensive income (loss), shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2022, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022**,** in conformity with accounting principles generally accepted in the United States of America.

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, 2022, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") and our report dated April 6, 2023 expressed an adverse opinion thereon.

**Basis for Opinion**

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's 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 Matter**

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates 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 matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

**Valuation and Recognition of Crude Oil and Natural Gas Properties Acquired in TransGlobe Energy Corporation Acquisition**

As described in Notes 2 and 4 to the consolidated financial statements, on October 13, 2022 the Company completed its acquisition of TransGlobe Energy Corporation ("TransGlobe") for purchase consideration of $274.1 million. The transaction qualified as a business combination under ASC 805, *Business Combinations,* and as such all assets and liabilities associated with the TransGlobe acquisition were recorded at their acquisition date fair values. As a result of the acquisition, the Company recognized wells, platforms and other production facilities of $243.7 million and undeveloped acreage of $30.2 million, which are included within crude oil and natural gas properties within the Company's consolidated balance sheet.

We identified the estimation of the fair value of wells, platforms and other production facilities and undeveloped acreage acquired from TransGlobe as a critical audit matter. The Company, with the assistance of outside consultants, used significant judgment to develop the estimated fair value of reserve quantities factoring in specific risk adjustment factors based on reserve category and the Company's weighted average cost of capital. Auditing these assumptions involved especially challenging and subjective auditor judgment and increased effort, including the involvement of professionals with specialized knowledge and skill in valuation.

The primary procedures we performed to address this critical audit matter included:

- Assessing the competence, capability and objectivity of the outside consultants engaged by the Company to assist in estimating the fair value of the acquired wells, platforms and other production facilities and undeveloped acreage and evaluating the valuation methodology selected.
- Utilizing professionals with specialized knowledge and skill in valuation to assist in assessing the reasonableness of risk adjustments based on reserve category and the weighted average cost of capital utilized by management.

/s/ BDO USA, LLP

We have served as the Company's auditor since 2016.

Houston, Texas

April 6, 2023

**Report of Independent Registered Public Accounting Firm**

Shareholders and Board of Directors
VAALCO Energy, Inc.
Houston, Texas

**Opinion on Internal Control over Financial Reporting**

We have audited VAALCO Energy, Inc.'s (the "Company's") internal control over financial reporting as of December 31, 2022, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO criteria"). In our opinion, the Company did not maintain, in all material respects, effective internal control over financial reporting as of December 31, 2022, based on the COSO criteria.

We do not express an opinion or any other form of assurance on management's statements referring to any corrective actions taken by the Company after the date of management's assessment.

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, 2022 and 2021, the related consolidated statements of operations and comprehensive income (loss), shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2022, and the related notes (collectively referred to as "the financial statements") and our report dated April 6, 2023 expressed an unqualified opinion thereon.

**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 Item 9A, Management's 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 U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit of internal control over financial reporting 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 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.

As indicated in the accompanying Item 9A, Management's Annual Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of TransGlobe Energy Corporation ("TransGlobe"), which was acquired on October 13, 2022, and which is included in the consolidated balance sheets of the Company as of December 31, 2022, and the related consolidated statements of income and comprehensive income (loss), stockholders' equity, and cash flows for the year then ended. TransGlobe constituted 48% and 62% of total assets and net assets, respectively, as of December 31, 2022, and 13% and 19% of revenues and net income, respectively, for the year then ended. Management did not assess the effectiveness of internal control over financial reporting of TransGlobe because of the timing of the acquisition which was completed on October 13, 2022. Our audit of internal control over financial reporting of the Company also did not include an evaluation of the internal control over financial reporting of TransGlobe.

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 the company's annual or interim financial statements will not be prevented or detected on a timely basis. Material weaknesses regarding management's failure to design and maintain effective controls over accounting for leases, complex accounting for business combinations, accounting for income taxes and financial reporting and consolidation have each been identified and described in management's assessment. These material weaknesses were considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2022 consolidated financial statements, and this report does not affect our report dated April 6, 2023 on those consolidated financial statements.

**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/ BDO USA, LLP

Houston, Texas

April 6, 2023

## VAALCO ENERGY, INC. AND SUBSIDIARIES
## CONSOLIDATED BALANCE SHEETS

| | As of December 31, 2022 | As of December 31, 2021 |
|---|---|---|
| | *(in thousands)* | |
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | **$ 37,205** | $ 48,675 |
| Restricted cash | **222** | 79 |
| Receivables: | | |
| Trade, net | **52,147** | 22,464 |
| Accounts with joint venture owners, net of allowance of $0.0 million in both periods presented | **15,830** | 345 |
| Foreign income taxes receivable | **2,769** | — |
| Other, net | **68,519** | 9,977 |
| Crude oil inventory | **3,335** | 1,593 |
| Prepayments and other | **20,070** | 5,156 |
| Total current assets | **200,097** | 88,289 |
| Crude oil and natural gas properties, equipment and other - successful efforts method, net | **495,272** | 94,324 |
| Other noncurrent assets: | | |
| Restricted cash | **1,763** | 1,752 |
| Value added tax and other receivables, net of allowance of $8.7 million and $5.7 million, respectively | **7,150** | 5,536 |
| Right of use operating lease assets | **2,777** | 10,227 |
| Right of use finance lease assets | **90,698** | — |
| Deferred tax assets | **35,432** | 39,978 |
| Abandonment funding | **20,586** | 21,808 |
| Other long-term assets | **1,866** | 1,176 |
| Total assets | **$ 855,641** | $ 263,090 |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| Current liabilities: | | |
| Accounts payable | **$ 59,886** | $ 18,797 |
| Accounts with joint venture owners | **—** | 3,233 |
| Accrued liabilities and other | **91,392** | 49,444 |
| Operating lease liabilities - current portion | **2,314** | 9,642 |
| Finance lease liabilities - current portion | **7,811** | — |
| Foreign income taxes payable | **—** | 3,128 |
| Current liabilities - discontinued operations | **687** | 13 |
| Total current liabilities | **162,090** | 84,257 |
| Asset retirement obligations | **41,695** | 33,949 |
| Operating lease liabilities - net of current portion | **686** | 587 |
| Finance lease liabilities - net of current portion | **78,248** | — |
| Deferred tax liabilities | **81,223** | — |
| Other long-term liabilities | **25,594** | — |
| Total liabilities | **389,536** | 118,793 |
| Commitments and contingencies (Note 12) | | |
| Shareholders' equity: | | |
| Preferred stock, $25 par value; 500,000 shares authorized, none issued | **—** | — |
| Common stock, $0.10 par value; 160,000,000 and 100,000,000 shares authorized, 119,482,680 and 69,562,774 shares issued, 107,852,857 and 58,623,451 shares outstanding, respectively | **11,948** | 6,956 |
| Additional paid-in capital | **353,606** | 76,700 |
| Accumulated other comprehensive income | **1,179** | — |
| Less treasury stock, 11,629,823 and 10,939,323 shares, respectively, at cost | **(47,652 )** | (43,847 ) |
| Retained earnings | **147,024** | 104,488 |
| Total shareholders' equity | **466,105** | 144,297 |
| Total liabilities and shareholders' equity | **$ 855,641** | $ 263,090 |

*See notes to consolidated financial statements.*

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2022** | **2021** | **2020** |
| | *(in thousands, except per share amounts)* | | |
| Revenues: | | | |
| Crude oil, natural gas and natural gas liquids sales | **$ 354,326** | $ 199,075 | $ 67,176 |
| Operating costs and expenses: | | | |
| Production expense | **112,661** | 81,255 | 37,315 |
| FPSO demobilization | **8,867** | — | — |
| Exploration expense | **258** | 1,579 | 3,588 |
| Depreciation, depletion and amortization | **48,143** | 21,060 | 9,382 |
| Impairment of proved crude oil and natural gas properties | — | — | 30,625 |
| General and administrative expense | **10,077** | 14,766 | 10,695 |
| Bad debt expense and other | **3,082** | 875 | 1,165 |
| Total operating costs and expenses | **183,088** | 119,535 | 92,770 |
| Other operating income (expense), net | **38** | (440) | (1,669) |
| Operating income (loss) | **171,276** | 79,100 | (27,263) |
| Other income (expense): | | | |
| Derivative instruments gain (loss), net | **(37,812)** | (22,826) | 6,577 |
| Interest income (expense), net | **(2,034)** | 10 | 155 |
| Other income (expense), net | **(8,048)** | 3,494 | 129 |
| Total other income (expense), net | **(47,894)** | (19,322) | 6,861 |
| Income (loss) from continuing operations before income taxes | **123,382** | 59,778 | (20,402) |
| Income tax expense (benefit) | **71,420** | (22,156) | 27,681 |
| Income (loss) from continuing operations | **51,962** | 81,934 | (48,083) |
| Loss from discontinued operations, net of tax | **(72)** | (98) | (98) |
| Net income (loss) | **$ 51,890** | $ 81,836 | $ (48,181) |
| Other comprehensive income (loss) | | | |
| Currency translation adjustments | **1,179** | — | — |
| Comprehensive income (loss) | **$ 53,069** | $ 81,836 | $ (48,181) |
| Basic net income (loss) per share: | | | |
| Income (loss) from continuing operations | **$ 0.74** | $ 1.38 | $ (0.83) |
| Loss from discontinued operations, net of tax | — | — | — |
| Net income (loss) per share | **$ 0.74** | $ 1.38 | $ (0.83) |
| Basic weighted average shares outstanding | **69,568** | 58,230 | 57,594 |
| Diluted net income (loss) per share: | | | |
| Income (loss) from continuing operations | **$ 0.73** | $ 1.37 | $ (0.83) |
| Loss from discontinued operations, net of tax | — | — | — |
| Net income (loss) per share | **$ 0.73** | $ 1.37 | $ (0.83) |
| Diluted weighted average shares outstanding | **69,982** | 58,755 | 57,594 |

*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, 2020 | 67,674 | (9,649) | $ 6,767 | $ 73,549 | $ — | $ (41,429) | $ 70,833 | $109,720 |
| Shares issued - stock-based compensation | 223 | (44) | 23 | 40 | — | — | — | 63 |
| Stock-based compensation expense | — | — | — | 848 | — | — | — | 848 |
| Treasury stock | — | (673) | — | — | — | (992) | — | (992) |
| Net loss | — | — | — | — | — | — | (48,181) | (48,181) |
| Balance at December 31, 2020 | 67,897 | (10,366) | 6,790 | 74,437 | — | (42,421) | 22,652 | 61,458 |
| Shares issued - stock-based compensation | 1,665 | (573) | 166 | 1,203 | — | — | — | 1,369 |
| Stock-based compensation expense | — | — | — | 1,060 | — | — | — | 1,060 |
| Treasury stock | — | — | — | — | — | (1,426) | — | (1,426) |
| Net income | — | — | — | — | — | — | 81,836 | 81,836 |
| Balance at December 31, 2021 | 69,562 | (10,939) | 6,956 | 76,700 | — | (43,847) | 104,488 | 144,297 |
| Shares issued - stock-based compensation | **614** | — | **61** | **251** | — | — | — | **312** |
| Stock-based compensation expense | — | — | — | **2,105** | — | — | — | **2,105** |
| Conversion of liability awards to equity | — | — | — | **5,336** | — | — | — | **5,336** |
| Acquisition of TransGlobe | **49,307** | — | **4,931** | **269,214** | — | — | — | **274,145** |
| Treasury stock | — | **(691)** | — | — | — | **(3,805)** | — | **(3,805)** |
| Dividend Distributions | — | — | — | — | — | — | **(9,354)** | **(9,354)** |
| Other comprehensive income | — | — | — | — | **1,179** | — | **—** | **1,179** |
| Net income | — | — | — | — | — | — | **51,890** | **51,890** |
| Balance at December 31, 2022 | **119,483** | **(11,630)** | **$ 11,948** | **$ 353,606** | **$ 1,179** | **$ (47,652)** | **$147,024** | **$466,105** |

*See notes to consolidated financial statements.*

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

| | Year Ended December 31, 2022 | 2021 | 2020 |
|---|---|---|---|
| | | (in thousands) | |
| CASH FLOWS FROM OPERATING ACTIVITIES: | | | |
| Net income (loss) | $ **51,890** | $ 81,836 | $ (48,181) |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | | |
| Loss from discontinued operations, net of tax | **72** | 98 | 98 |
| Depreciation, depletion and amortization | **48,143** | 21,060 | 9,382 |
| Bargain purchase gain | **(10,819)** | (7,651) | — |
| Impairment of proved crude oil and natural gas properties | **—** | — | 30,625 |
| Other amortization | — | — | 181 |
| Deferred taxes | **44,805** | (39,978) | 24,159 |
| Unrealized foreign exchange (gain) loss | **(1,043)** | (291) | 91 |
| Stock-based compensation | **2,200** | 2,459 | 114 |
| Cash settlements paid on exercised stock appreciation rights | **(827)** | (3,271) | (275) |
| Derivative instruments (gain) loss, net | **37,812** | 22,826 | (6,577) |
| Cash settlements received (paid) on matured derivative contracts, net | **(42,935)** | (18,020) | 7,216 |
| Cash settlements paid on asset retirement obligations | **(6,577)** | — | — |
| Bad debt expense and other | **3,082** | 875 | 1,165 |
| Other operating loss, net | **(38)** | 440 | 869 |
| Operational expenses associated with equipment and other | **2,052** | 2,415 | 1,601 |
| Change in operating assets and liabilities: | | | |
| Trade receivables | **18,385** | (11,308) | 14,335 |
| Accounts with joint venture owners | **(18,929)** | 1,594 | 4,016 |
| Other receivables | **(9,290)** | (9,736) | 1,405 |
| Crude oil inventory | **(1,742)** | 5,022 | (2,834) |
| Prepayments and other | **(4,387)** | 1,617 | (1,126) |
| Value added tax and other receivables | **(5,193)** | (1,593) | (1,268) |
| Other long-term assets | **(2,730)** | (1,176) | — |
| Accounts payable | **23,920** | (922) | (842) |
| Foreign income taxes receivable/payable | **(5,897)** | 2,268 | (4,880) |
| Accrued liabilities and other | **6,964** | 1,645 | (1,383) |
| Net cash provided by continuing operating activities | **128,918** | 50,209 | 27,891 |
| Net cash used in discontinued operating activities | **(72)** | (92) | (441) |
| Net cash provided by operating activities | **128,846** | 50,117 | 27,450 |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | | |
| Property and equipment expenditures | **(159,897)** | (16,558) | (20,008) |
| Cash acquired from TransGlobe acquisition | **36,686** | — | — |
| Acquisition of crude oil and natural gas properties | **—** | (22,505) | (4,320) |
| Net cash used in continuing investing activities | **(123,211)** | (39,063) | (24,328) |
| Net cash used in discontinued investing activities | — | — | — |
| Net cash used in investing activities | **(123,211)** | (39,063) | (24,328) |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | | |
| Proceeds from the issuances of common stock | **312** | 1,369 | 63 |
| Dividend distribution | **(9,354)** | — | — |
| Treasury shares | **(3,805)** | (1,426) | (992) |
| Deferred financing costs | **(2,069)** | — | — |
| Payments of finance lease | **(3,039)** | — | — |
| Net cash used in continuing financing activities | **(17,955)** | (57) | (929) |
| Net cash used in discontinued financing activities | — | — | — |
| Net cash used in financing activities | **(17,955)** | (57) | (929) |
| Effects of exchange rate changes on cash | **(218)** | — | — |
| NET CHANGE IN CASH, CASH EQUIVALENTS AND RESTRICTED CASH | **(12,538)** | 10,997 | 2,193 |
| CASH, CASH EQUIVALENTS AND RESTRICTED CASH AT BEGINNING OF PERIOD | **72,314** | 61,317 | 59,124 |
| CASH, CASH EQUIVALENTS AND RESTRICTED CASH AT END OF PERIOD | $ **59,776** | $ 72,314 | $ 61,317 |

*See notes to consolidated financial statements.*

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2022** | **2021** | **2020** |
| | | *(in thousands)* | |
| Supplemental disclosure of cash flow information: | | | |
| Income taxes received in cash | **$ —** | $ — | $ (696) |
| Income taxes paid in-kind with crude oil | **$ 26,257** | $ 20,103 | $ 8,738 |
| Interest paid, net of amounts capitalized | **$ 1,656** | $ — | $ — |
| Supplemental disclosure of non-cash investing and financing activities: | | | |
| Property and equipment additions incurred but not paid at end of period | **$ 41,060** | $ 15,021 | $ 3,966 |
| Non-cash consideration exchanged in the acquisition of TransGlobe | $ **274,145** | $ — | $ — |
| Recognition of right-of-use operating lease assets and liabilities | **$ —** | $ 581 | $ 1,478 |
| Recognition of right-of-use finance lease assets and liabilities | **$ 87,166** | $ — | $ — |
| Reclassification of other long-term assets to right-of-use finance lease assets | $ **4,116** | $ — | $ — |
| Liability awards converted to equity | **$ 5,336** | $ — | $ — |
| Asset retirement obligations | **$ —** | $ 21,733 | $ 359 |

*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. As operator, the Company has production operations and conducts exploration activities in Gabon and Canada and hold interests in two production sharing contracts ("PSCs") in Egypt. The Company has opportunities to participate in development and exploration activities in Equatorial Guinea, West Africa. As discussed further in Note 4 below, VAALCO has discontinued operations associated with activities in Angola, West Africa and Yemen.

On October 13, 2022, the Company and VAALCO Energy Canada ULC ("AcquireCo"), an indirect wholly-owned subsidiary of the Company, completed the previously announced business combination involving TransGlobe Energy Corporation ("TransGlobe"), whereby AcquireCo acquired all of the issued and outstanding TransGlobe common shares pursuant to a plan of arrangement (the "Arrangement") and TransGlobe became a direct wholly-owned subsidiary of AcquireCo and an indirect wholly-owned subsidiary of VAALCO in accordance with the terms of an arrangement agreement entered into by VAALCO, AcquireCo and TransGlobe on July 13, 2022 (the "Arrangement Agreement"). Prior to the Arrangement, TransGlobe was a cash flow-focused oil and gas exploration and development company whose activities were concentrated in Egypt and Canada. The post-Arrangement company (the "Combined Company") is an African-focused operator with a diverse portfolio of assets in Gabon, Egypt, Equatorial Guinea and Canada. See Note 4 for further discussion regarding the Arrangement.

As of December 31, 2022, the Company's consolidated subsidiaries were VAALCO Gabon (Etame), Inc., VAALCO Production (Gabon), Inc., VAALCO Gabon S.A., VAALCO Angola (Kwanza), Inc., VAALCO Energy (EG), Inc., VAALCO Energy Mauritius (EG) Limited, VAALCO Energy, Inc. (UK Branch), VAALCO Energy (USA), Inc, VAALCO Energy (International), LLC, VAALCO Energy (Holdings), LLC, TransGlobe Energy Corporation, TG Energy UK Ltd, TransGlobe Petroleum International Inc., TG Holdings Yemen Inc., TransGlobe West Bakr Inc., TransGlobe West Gharib Inc., TG Energy Marketing Inc., and TG NW Gharib Inc., TG S Ghazalat Inc.

With respect to the novel strain of COVID-19, during 2021, and continuing in 2022, crude oil prices have experienced significant improvement and oil demand has stabilized over multiple quarters removing much of the uncertainty and instability in the industry. However, during the second quarter of 2022 the BA.5 strain of the Omicron variant caused surges in infections worldwide. While COVID-19 related travel restrictions have gradually eased as governments and people continue to have increasing access to vaccines that help reduce the spread of COVID-19, new surges in infections and hospitalizations could alter the current environment. The significant decline in oil prices experienced in 2020 was, in part, due to disruptions in the worldwide economy due to the COVID-19 pandemic which quarantined people and restricted travel. To date the Company's operations have not been materially impacted by COVID-19, and worldwide the Company is seeing improving economic activity while managing the risk of a resurgence, but there can be no guarantees that COVID-19 will not have an impact on the Company or its operations.

In July 2021, the Organization of the Petroleum Exporting Countries, Russia and other allied producing countries (collectively, "OPEC+") agreed to increase production beginning in August 2021 and to gradually phase out prior production cuts by September 2022. However, as a result of the recent decline in oil prices, on October 5, 2022, OPEC+ announced plans to reduce overall oil production by 2 MMBbls per day starting November 2022 through December 2023. The Company has not received any mandate to reduce its current oil production from the Etame Marin block as a result of the OPEC+ initiative.

For the years ended December 31, 2022 and 2021, crude oil prices have improved, there were no disruptions to operations as a result of COVID-19 or any strain thereof, global economic activity has steadily increased, and oil demand has stabilized over multiple quarters removing much of the uncertainty and instability in the industry. Therefore, no additional charges or impairments were required for the year ended December 31, 2022 or 2021. Crude oil prices have stabilized. The average annual Brent price per barrel for the year ended December 31, 2020 was $41.96 increasing 69% to $70.86 for December 31, 2021 and further increasing 42% to $100.93 for the year ended December 31, 2022.

During the year ended December 31, 2022, the Company noticed that the lead times associated with obtaining materials to support its operations and drilling activities have lengthened and, in some cases, prices for fuel and materials have increased. Management believes the ongoing war between Russia and Ukraine and the slowdown of the economy in China and their related impact on the global economy are causing supply chain issues and energy concerns in parts of the global economy. In addition, increased inflation, higher interest rates and current turmoil in certain governments are impacting the global supply chain market.

While the current commodity price environment is still favorable and the Company has not experienced material disruptions to its operations as a result of COVID-19 or as result of other forces, including the Russia/Ukraine conflict or slowdown in the Chinese economy, affecting the global market, any emergence of a new variant or further deteriorations of the global supply chain market may have a material adverse impact on financial results and business operations of the Company, including the timing and ability of the Company to complete future drilling campaigns and other efforts required to advance the development of its crude oil, natural gas and NGLs properties.

***NYSE Noncompliance Notice***

On April 3, 2023, the Company was notified by the New York Stock Exchange (the "NYSE") that it was not in compliance with the NYSE's continued listing requirements under the timely filing criteria established in Section 802.01E of the NYSE Listed Company Manual as a result of its failure to timely file its Annual Report on Form 10-K for the fiscal year ended December 31, 2022. By filing this report, the Company believes it has remedied its non-compliance.

## 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

***Principles of consolidation*** – The accompanying consolidated financial statements ("Financial Statements") include the accounts of VAALCO and its wholly owned subsidiaries. Investments in unincorporated joint ventures and undivided interests in certain 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 require extensive 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.

***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 time duration. Current amounts in restricted cash at December 31, 2022 and 2021 each include an escrow amount representing bank guarantees for customs clearance in Gabon. Long-term amounts at December 31, 2022 and 2021 include a charter payment escrow for the FPSO offshore Gabon as discussed in Note 12. 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, | |
|---|---|---|
| | **2022** | **2021** |
| | *(in thousands)* | |
| Cash and cash equivalents | **$ 37,205** | $ 48,675 |
| Restricted cash - current | **222** | 79 |
| Restricted cash - non-current | **1,763** | 1,752 |
| Abandonment funding | **20,586** | 21,808 |
| Total cash, cash equivalents and restricted cash | **$ 59,776** | $ 72,314 |

The Company conducts regular abandonment studies to update the estimated costs to abandon the offshore wells, platforms and facilities on the Etame Marin block. This cash funding is reflected under "Other noncurrent assets" as "Abandonment funding" on 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. See Note 11 for further discussion.

On February 28, 2019, the Gabonese branch of the international commercial bank holding the abandonment funds in a U.S. dollar ("USD") denominated account advised the Company that the bank regulator required transfer of the funds to the Bank Of Central African States (BEAC) which is the Central Bank of the Economic and Monetary Community of Central Africa (CEMAC) of which Gabon is one of the six member states, for conversion to local currency with a credit back to the Gabonese branch in local currency. The Etame PSC provides these payments must be denominated in USD and the CEMAC regulations provide for establishment of a USD account with the Central Bank. Although the Company requested establishment of such account, the Central Bank did not comply with its requests since they were working on an abandonment fund common policy for the oil and gas Industry as well as the mining industry. As a result, the Company was not able to make the annual abandonment funding payment for the years 2019 through 2022 totaling $5.8 million, net to VAALCO based on the 2018 abandonment study. On January 12, 2023, after continued discussions with various BEAC and government officials, the Company was allowed to re-establish a USD denominated account and made whole for the original USD amount of $37.3 million that was in the account prior to conversion to a local currency account in 2019. The Company is 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.

***Accounts with joint venture owners*** – 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.

***Accounts Receivable and Allowance for Doubtful Accounts*** – The Company's accounts receivable results from sales of crude oil production, joint interest billings to its joint interest owners for their share of expenses on joint venture projects for which the Company is the operator, and receivables from the government of Gabon for reimbursable Value-Added Tax ("VAT"). Collection efforts, including remedies provided for in the contracts, are pursued to collect overdue amounts owed to the Company. Portions of the Company's costs in Gabon (including the Company's VAT receivable) are denominated in the local currency of Gabon, the Central African CFA Franc ("XAF"). Most of these receivables have payment terms of 30 days or less. The Company monitors the creditworthiness of the counterparties, and it has obtained credit enhancements from some parties in the form of parental guarantees or letters of credit. Joint owner receivables are secured through cash calls and other mechanisms for collection under the terms of the joint operating agreements.

The Company routinely assesses the recoverability of all material receivables to determine their collectability. The Company accrues a reserve on a receivable when, based on management's judgment, it is probable that a receivable will not be collected and the amount of such reserve may be reasonably estimated. When collectability is in doubt, the Company records an allowance against the accounts receivable and a corresponding income charge for bad debts, which appears in the "Bad debt expense and other" line item of the consolidated statements of operations and comprehensive income (loss).

As of December 31, 2022, the outstanding VAT receivable balance in Gabon, excluding the allowance for bad debt, was approximately $21.8 million ($13.9 million, net to VAALCO). As of December 31, 2021, the outstanding VAT receivable balance, excluding the allowance for bad debt, was approximately $14.5 million ($9.6 million, net to VAALCO). As of December 31, 2022, the exchange rate was XAF 612.6 = $1.00. As of December 31, 2021, the exchange rate was XAF 578.2 = $1.00. 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) income, net" line item of the consolidated statements of operations and comprehensive income (loss).

The following table provides an analysis of the change in the allowance:

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2022** | **2021** | **2020** |
| | | ***(in thousands)*** | |
| Allowance for bad debt | | | |
| Balance at beginning of period | **$ (5,741)** | $ (2,273) | $ (1,508) |
| Bad debt charges, net of receipts | **(3,082)** | (875) | (1,165) |
| Adjustment associated with reversal of allowance on Mutamba receivable | **—** | — | 593 |
| Adjustment associated with Sasol Acquisition | **—** | (2,879) | — |
| Foreign currency gain (loss) | **119** | 286 | (193) |
| Balance at end of period | **$ (8,704)** | $ (5,741) | $ (2,273) |

***Other receivables***– Under the terms of the Etame PSC, the Company can be required to contribute to meeting domestic market needs of the Republic of Gabon by delivering to it, or another entity designated by the Republic of Gabon, an amount of crude oil proportional to the Company's share of production to the total production in Gabon over the year. In 2021, the Company was notified by the Republic of Gabon to deliver to a refinery its proportionate share of crude oil to meet the domestic market need as per the terms of the Etame PSC. The Company is entitled, per the Etame PSC, to a fixed selling price for the oil delivered. Since the crude-oil produced by the Company was not compatible with the crude-oil requirements of the refinery, the Company entered into two contracts to fulfill its domestic market needs obligation under the Etame PSC. One contract was to purchase oil from another producer that produced the compatible oil the refinery needs and another contract with the refinery itself to deliver the crude oil to. Under the contract with the provider of the crude oil, the third-party provider is entitled to a selling price consistent with the price the Company receives under the terms of the Etame PSC for the delivery of the crude oil to the refinery. As a result of these contracts and timing differences between when the oil is procured and when it is delivered to and paid for by the refinery, included in the Company's December 31, 2022 consolidated balance sheet are current receivables in the "Other, net" line item of approximately $18.2 million for amounts due to the Company from the refinery for 195 MBbls delivered in September through December 2022, and a $17.9 million current liability included in the "Accounts payable" line item for amounts due to the oil supplier for 195 MBbls of crude oil purchased from the supplier in September through December 2022.

On January 19, 2022, TransGlobe's West Gharib, West Bakr and North West Gharib (collectively the "Eastern Desert") concessions were merged into the Merged Concession Agreement with EGPC. The Merged Concession includes improved cost recovery and production sharing terms scaled to oil prices with a new 15-year development term and a 5-year extension option. Upon execution of the Merged Concession, there was an effective date adjustment owed to the Company for the difference between historic and Merged Concession Agreement commercial terms applied against Eastern Desert production from the Merged Concession Effective Date, February 1, 2020. The cumulative amount of the effective date adjustment was estimated at $67.5 million. At December 31, 2022, the Company received $17.2 million of the receivable and the remaining $50.3 million is recorded on the consolidated balance sheet in current receivables in the "Other, net" line item.

***Crude oil inventory*** – Crude oil inventories are carried at the lower of cost or net realizable value. In Gabon, inventories represent the Company's share of crude oil produced and stored on the FSO at December 31, 2022 and the FPSO at December 31, 2021, but unsold at the end of each period. In Egypt, inventory consists of the Company's entitlement crude oil barrels not yet sold. Crude oil inventory is valued at the lower of cost or net realizable value.

***Prepayments and other*** – Included in "Prepayments and other" line item of the Company's December 31, 2022 consolidated balance sheet are $4.0 million of prepayments related to fixed assets, $4.8 million of prepayments related to royalties in Gabon, $2.7 million in prepaid insurance and other, $0.9 million in prepaid charter hire for the FSO and $7.2 million of prepayment and other assets related to the Company's Canadian and Egyptian operations.

***Materials and supplies*** – Materials and supplies, which are included in the "Prepayments and other" line item of the consolidated balance sheet, are primarily used for production related activities. These assets are valued at the lower of cost, determined by the weighted-average method, or net realizable value.

***Crude oil, natural gas and NGLs properties, equipment and other*** – The Company uses the successful efforts method of accounting for crude oil, natural gas and NGLs producing activities. Management believes that this method is preferable, as the Company has focused on exploration activities wherein there is risk associated with future success and as such earnings are best represented by drilling results.

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

***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. Geological and geophysical costs are expensed as incurred. Costs of seismic studies that are utilized in development drilling within an area of proved reserves are capitalized as development costs. Amounts of seismic costs capitalized are based on only those blocks of data used in determining development well locations. To the extent that a seismic project covers areas of both developmental and exploratory drilling, those seismic costs are proportionately allocated between development costs and exploration expense.

***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 proved developed reserves. Depletion of developed leasehold acquisition costs are provided on a block basis under the unit-of-production method based upon estimates of 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.

***Impairment*** – The Company reviews the crude oil, natural gas and NGLs producing properties 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 if commodity prices fall below a level that significantly effects anticipated future cash flows. 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. Capitalized equipment inventory is reviewed regularly for obsolescence. 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 undeveloped acreage in the Etame Marin block in Gabon, Canada, Egypt and in Block P in Equatorial Guinea. See Note 9 for further discussion.

***Purchase Accounting*** – On October 13, 2022, the Company and AcquireCo, an indirect wholly-owned subsidiary of the Company, completed the business acquisition of TransGlobe and TransGlobe became a direct wholly-owned subsidiary of AcquireCo and an indirect wholly-owned subsidiary of VAALCO, pursuant to the Arrangement Agreement on July 13, 2022. The Company made various assumptions in determining the fair values of acquired assets and liabilities assumed. In order to allocate the purchase price, the Company developed fair value models with the assistance of outside consultants. These fair value models were used to determine the fair value associated with the reserves and applied discounted cash flows to expected future operating results, considering expected growth rates, development opportunities, and future pricing assumptions. The fair value of working capital assets acquired and liabilities assumed were transferred at book value, which approximates fair value due to the short-term nature of the assets and liabilities. The fair value of the fixed assets acquired was based on estimates of replacement costs and the fair value of liabilities assumed was based on their expected future cash outflows. See Note 4 for further discussion.

On February 25, 2021, VAALCO Gabon S.A., a wholly owned subsidiary of the Company, completed the acquisition of Sasol Gabon S.A.'s ("Sasol's") 27.8% working interest in the Etame Marin block offshore Gabon pursuant to the sale and purchase agreement ("SPA") dated November 17, 2020 (the "Sasol Acquisition"). The Company made various assumptions in determining the fair values of acquired assets and liabilities assumed. In order to allocate the purchase price, the Company developed fair value models with the assistance of outside consultants. These fair value models were used to determine the fair value associated with the reserves and applied discounted cash flows to expected future operating results, considering expected growth rates, development opportunities, and future pricing assumptions. The fair value of working capital assets acquired and liabilities assumed were transferred at book value, which approximates fair value due to the short-term nature of the assets and liabilities. The fair value of the fixed assets acquired was based on estimates of replacement costs and the fair value of liabilities assumed was based on their expected future cash outflows. See Note 4 for further discussion.

***Lease commitments*** – At inception, contracts are reviewed to determine whether an agreement contains a lease as defined under Accounting Standards Codification ("ASC") 842, Leases. Further, 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. ROU assets for operating leases are recorded under "Right of use operating lease assets" and the current portion and long-term portion of the lease liabilities for operating leases are reflected in "Operating lease liabilities – current portion" and "Operating lease liabilities – net of current portion" within the consolidated balance sheets. ROU assets for financing leases are recorded within "Right of use finance lease assets" and the current portion and long-term portion of the lease liabilities for financing leases are reflected in "Finance lease liabilities – current portion" and "Finance lease liabilities – net of current portion" within the consolidated balance sheets.

***Asset retirement obligations ("ARO")*** – The Company has significant 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 is difficult and 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. 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. 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 asset balance or income statement, as appropriate. Depreciation of capitalized asset retirement costs and accretion of asset retirement obligations are recorded over time. Depreciation is generally determined on a units-of-production basis for crude oil, natural gas and NGLs 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. See Note 11 for further discussion.

***Revenue recognition*** – The Company's revenues are derived primarily 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. VAALCO mainly satisfies its performance obligations at a point in time and the amounts of revenues recognized relating to performance obligations satisfied over time are not significant. See Note 7 for further discussion.

In connection with the acquisition of TransGlobe on October 13, 2022, the Company has elected to continue its policy regarding shipping and handling costs and are presenting these costs net within revenue in the consolidated statements of operations and comprehensive income (loss). In addition, the Company has elected to recognize revenue from oil, natural gas and NGL's on the basis of the Company's net working interest, less royalties the consolidated statements of operations and comprehensive income (loss). Any imbalances from an underlift or overlift position are valued based on the actual sales proceeds received.

***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 requisite or derived service period, using the straight-line attribution method over the service period for each separately vesting portion of the award as if the award was, in-substance, multiple awards. 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.

Unless the awards contain a market condition, previously recognized expense related to forfeited awards is reversed in the period in which the forfeiture occurs. For awards containing a market condition, previously recognized stock-based compensation expense is not reversed when the awards are forfeited. See Note 17 for further discussion.

***Foreign currency transactions*** – The U.S. dollar is the functional currency of most of the Company's foreign operating subsidiaries. However, in connection with the Company's acquisition of TransGlobe, the Company acquired TransGlobe's Canadian operations whose functional currency is 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). Both realized and unrealized foreign exchange gain and losses are recorded within the consolidated statements of operations and comprehensive income line item "Other (expense) income, net". The Company recognized losses on foreign currency transactions of $4.2 million in 2022, $0.7 million in 2021 and a gain on foreign currency transactions of $0.2 million in 2020.

***Income taxes*** – The annual 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.

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.

In certain jurisdictions, the Company may deem the likelihood of realizing deferred tax assets as remote where the Company expects that, due to the structure of operations and applicable law, the operations in such jurisdictions will not give rise to future tax consequences. For such jurisdictions, the Company has not recognized deferred tax assets. Should the expectations change regarding the expected future tax consequences, the Company may be required to record additional deferred taxes that could have a material effect on the consolidated financial position and results of operations. See Note 8 for further discussion.

***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). See Note 10 for further discussion.

***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 represent quoted prices in active markets for identical assets or liabilities (for example, exchange-traded commodity derivatives).
>
> Level 2 – Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (for example, quoted market prices for similar assets or liabilities in active markets or quoted market prices for identical assets or liabilities in markets not considered to be active, inputs other than quoted prices that are observable for the asset or liability, or market-corroborated inputs).
>
> Level 3 – Inputs that are not observable from objective sources, such as internally developed assumptions used in pricing an asset or liability (for example, an estimate of future cash flows used in the internally developed present value of future cash flows model that underlies the fair-value measurement).

***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, asset retirement assets and liabilities, other long-lived assets and assets acquired and liabilities assumed in a business combination. Generally, a cash flow model is used in combination with inflation rates and credit-adjusted, risk-free discount rates or industry rates to determine the fair value of the assets and liabilities. Based upon review of the fair value hierarchy, the inputs used in these fair value measurements, such as the underlying future commodity prices included in the Company's estimated future cash flows of its proved oil and gas properties were determined using an average weekly forward strip prices as of the closing date of the acquisition, are considered Level 3 inputs.

***Fair value of financial instruments*** – The Company's current assets and liabilities include financial instruments such as cash and cash equivalents, restricted cash, accounts receivable, derivative assets and liabilities, accounts payable, accrued liabilities, liabilities for SARs and guarantees. As discussed further in Note 10, derivative assets and liabilities are measured and reported at fair value each period with changes in fair value recognized in net income. The derivatives referenced below are reported in "Accrued liabilities and other" on the consolidated balance sheet. SARs liabilities are measured and reported at fair value using level 2 inputs each period with changes in fair value recognized in net income. The current portion of the SARs liabilities is reported in "Accrued liabilities and other" on the consolidated balance sheet while the long-term portion is reported in "Other long-term liabilities". With respect to cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities, the carrying value of each financial instrument approximates fair value primarily due to the short-term maturity of these instruments and are considered Level 1 inputs. The Company generally extends unsecured credit to these clients; therefore, collection of receivables may be affected by the economy surrounding the oil and natural gas industry or other economic conditions. The Company closely monitors extensions of credit and may negotiate payment terms that mitigate risk.

| | Balance Sheet Line | As of December 31, 2022 Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|---|
| | | | (in thousands) | | |
| Assets | | | | | |
| Derivative asset | Prepayments and other | $ — | **$ 102** | $ — | **$ 102** |
| | | $ — | **$ 102** | $ — | **$ 102** |
| Liabilities | | | | | |
| SARs liability | Accrued liabilities and other | $ — | **$ 556** | $ — | **$ 556** |
| | | $ — | **$ 556** | $ — | **$ 556** |

| | Balance Sheet Line | As of December 31, 2021 Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|---|
| | | | (in thousands) | | |
| Liabilities | | | | | |
| SARs liability | Accrued liabilities and other | $ — | $ 609 | $ — | $ 609 |
| Derivative liability | Accrued liabilities and other | — | 4,806 | — | 4,806 |
| | | $ — | $ 5,415 | $ — | $ 5,415 |

***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. See Note 6 for further discussion.

***Other, net*** – "Other, net" in non-operating income and expenses includes gains and losses from foreign currency transactions as discussed above, as well as taxes other than income taxes.

***Other comprehensive income*** – All of the Company's other comprehensive income arises from TransGlobe's Canadian operations whose functional currency is the Canadian dollar. Translation gains and losses occur when translating the financial statements of non-U.S. functional currency operations to the USD. These translation gains and losses are recorded as currency translation adjustments and presented as other comprehensive income on the consolidated statements of operations and comprehensive income (loss). Translations occur as follows:

- Income and expenses are translated at the date of the transaction
- Assets and liabilities are translated at the prevailing rate on the balance sheet date. On the date of acquisition, October 13, 2022, the exchange rate to convert Canadian dollars ("CAD") to US dollars ("USD") was 0.724. At December 31, 2022, the exchange rate was .0.738 USD.

## 3. NEW ACCOUNTING STANDARDS

***Adopted***

In June 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Codification ("ASU") No. 2016-13, *Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments* ("ASU 2016-13") related to the calculation of credit losses on financial instruments. All financial instruments not accounted for at fair value will be impacted, including the Company's trade and joint venture owners' receivables. Allowances are to be measured using a current expected credit loss ("CECL") model as of the reporting date that is based on historical experience, current conditions and reasonable and supportable forecasts. This is significantly different from the current model that increases the allowance when losses are probable. ASU 2016-13 is effective for Securities and Exchange Commission filers, excluding smaller reporting companies, for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. As a smaller reporting company, the Company was required to adopt the new standard for the fiscal years beginning after December 15, 2022, including interim periods within those fiscal years.

As of January 1, 2023, the Company adopted the standard, and the adoption of the standard did not have a material impact on its consolidated financial statements.

***Not Yet Adopted***

In March 2020, the FASB issued ASU 2020-04, "Reference Rate Reform (Topic 848)," which provides optional expedients and exceptions for applying U.S. GAAP to debt contracts, receivables, leases, derivatives, and other contracts impacted by reference rate reform and other transactions affected by the cessation of the LIBOR. The expiration date of ASU 2020-04 was December 31, 2022.

In December 2022, the FASB issued ASU 2022-06, "Reference Rate Reform (Topic 848): Deferral of the Sunset Date of Topic 848, to extend the expiration date of Topic 848 through December 31, 2024. The expedients, if adopted, can be applied prospectively. As the Company implements alternative rates from LIBOR into our current contracts, it is evaluating whether to apply any of these expedients and, if elected, will adopt these standards when LIBOR is discontinued.

## 4. ACQUISITIONS AND DISPOSITIONS

***Acquisition of TransGlobe Energy Corporation***

On October 13, 2022, the Company and AcquireCo completed the previously announced business combination with TransGlobe whereby AcquireCo acquired all of the issued and outstanding common shares of TransGlobe and TransGlobe became a direct wholly owned subsidiary of AcquireCo and an indirect wholly owned subsidiary of the Company pursuant to an Arrangement agreement entered into by the Company, AcquireCo and TransGlobe on July 13, 2022.

At the effective time of the Arrangement and pursuant to the Arrangement Agreement, each common share of TransGlobe issued and outstanding immediately prior to the effective time of the Arrangement (the "TransGlobe common shares") was converted into the right to receive 0.6727 (the "exchange ratio") of a share of VAALCO common stock, par value $0.10 per share. The total number of VAALCO shares issued to TransGlobe's shareholders was approximately 49.3 million. The Arrangement resulted in VAALCO stockholders owning approximately 54.5%, and TransGlobe shareholders owning approximately 45.5% of the Combined Company, calculated based on vested outstanding shares of each company as of the date of the Arrangement Agreement. The Combined Company results of operations of VAALCO and TransGlobe for the period of October 14, 2022 to December 31, 2022 are included in the Company's consolidated results for the period ending December 31, 2022.

Prior to the Arrangement, TransGlobe was a cash flow-focused oil and gas exploration and development company whose activities were concentrated in Egypt and Canada. The Combined Company is an African-focused operator with a portfolio of assets in Gabon, Egypt, Equatorial Guinea and Canada. The transaction qualifies as a business combination under ASC 805, *Business Combinations* and the Company is the accounting acquiror.

The actual impact of the Arrangement was an increase to “Crude oil, natural gas and NGLs sales” of $47.6 million and $10.0 million of “Net income” in the consolidated statements of operations and comprehensive income for the year ended December 31, 2022.

| | October 13, 2022 *(in thousands)* |
|---|---|
| Purchase Consideration | |
| Common stock issued to TransGlobe shareholders | $ 274,145 |

| | October 13, 2022 *(in thousands)* |
|---|---|
| Assets acquired: | |
| Cash | $ 36,686 |
| Wells, platforms and other production facilities | 243,669 |
| Equipment and other | 2,099 |
| Undeveloped acreage | 30,216 |
| Accounts receivable - trade | 48,068 |
| Accounts receivable - other | 50,275 |
| Accounts with joint venture owners | 68 |
| Right of use operating leases | 1,609 |
| Right of use financing leases | 204 |
| Prepayment and other | 7,627 |
| Liabilities assumed: | |
| Asset retirement obligations | (6,134) |
| Accounts payable | (10,223) |
| Accrued liabilities and other | (50,128) |
| Operating lease liabilities - current portion | (961) |
| Financing lease liabilities - current portion | (125) |
| Operating lease liabilities - net of current portion | (688) |
| Financing lease liabilities - net of current portion | (21) |
| Deferred tax liabilities | (40,964) |
| Other long-term liabilities | (26,313) |
| Bargain purchase gain | (10,819) |
| Total purchase price | $ 274,145 |

All assets and liabilities associated with TransGlobe, including crude oil, natural gas and NGLs properties, asset retirement obligations and working capital items, were recorded at their fair value. The Company used estimated future crude oil prices as of the closing date, October 13, 2022, to apply to the estimated reserve quantities acquired and market participant assumptions to the estimated future operating and development costs to arrive at the estimates of future net revenues. The future net revenues were discounted using a weighted average cost of capital to determine the fair value at closing. The valuations to derive the purchase price included the use of both proved and unproved categories of reserves, expectation for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates, and specific risk adjustment factors based on reserve category discount rates. Other significant estimates were used by the Company to determine the fair value of assets acquired and liabilities assumed. The purchase price allocation is preliminary pending final determination of the fair values of certain assets and liabilities, primarily the accounts receivable, asset retirement obligations, accounts payable and any contingencies, and any related tax impacts. As a result of comparing the purchase price to the fair value of the assets acquired and liabilities assumed a $10.8 million bargain purchase gain was recognized. The bargain purchase gain of $10.8 million is included in “Other income (expense), net” in the consolidated statements of operations and comprehensive income (loss). The bargain purchase gain was due to the decrease in the share price of VAALCO stock from the time period when the arrangement agreement was signed, July 13, 2022 and the share price at closing, October 13, 2022 while the exchange ratio, of TransGlobe shares converted to VAALCO shares, remained the same.

For the twelve months ended December 31, 2022, included in the line item "Other income (expense), net" is $14.6 million of transactions costs associated with the Arrangement with TransGlobe.

In connection with the Arrangement with TransGlobe and pursuant to the Arrangement Agreement, at the effective time of the Arrangement, certain awards previously issued to TransGlobe’s key employees and board members who continued their relationship as employees or board members of VAALCO following the Arrangement, continue to be governed by the applicable TransGlobe plan, provided that each such applicable plan has been amended to provide that VAALCO common stock shall be issuable in lieu of TransGlobe common stock with respect to TransGlobe’s deferred share units (“DSU”s), performance share units (“PSU”s) and restricted stock units (“RSU”s), in each case, based on the exchange ratio in the Arrangement. For the PSUs that remained outstanding following the effective time of the Arrangement as described in the immediately preceding sentence, the applicable vesting percentage was determined by the TransGlobe board of directors to be 200% for PSUs granted in 2020 and 2021; and 64.4% for PSUs granted in 2022.

On the effective date of the Arrangement, October 13, 2022, the combined fair value of the DSUs, PSU's and RSU's from TransGlobe was $6.0 million. On December 16, 2022, the awards were amended from cash-settled liability awards to equity awards. On the date of this conversion, the awards were revalued, based on VAALCO's share price, and the Company recognized a gain of $0.6 million in its consolidated statements of operations and comprehensive income. See Note 17, for further information on the DSUs, PSUs and RSUs after the conversion.

***Acquisition of Sasol Gabon S.A.’s Interest in Etame***

On February 25, 2021, VAALCO Gabon S.A. completed the acquisition of Sasol’s 27.8% working interest in the Etame Marin block offshore Gabon pursuant to the SPA. The effective date of the transaction was July 1, 2020. Prior to the Sasol Acquisition, the Company owned and operated a 31.1% working interest in Etame. The Sasol Acquisition increased the Company’s working interest to 58.8%. As a result of the Sasol Acquisition, the net portion of production and costs relating to the Company’s Etame operations increased from 31.1% to 58.8%. Reserves, production and financial results for the interests acquired in the Sasol Acquisition have been included in VAALCO’s results for periods after February 25, 2021.

The following amounts represent the allocation of the purchase price to the assets acquired and liabilities assumed in the Sasol Acquisition:

| | February 25, 2021 *(in thousands)* |
|---|---|
| Purchase Consideration | |
| Cash | $ 33,959 |
| Fair value of contingent consideration | 4,647 |
| Total purchase consideration | $ 38,606 |

| | | February 25, 2021 (in thousands) |
|---|---|---|
| Assets acquired: | | |
| Wells, platforms and other production facilities | $ | 37,176 |
| Equipment and other | | 5,568 |
| Value added tax and other receivables | | 1,234 |
| Abandonment funding | | 11,781 |
| Accounts receivable - trade | | 11,220 |
| Other current assets | | 3,963 |
| Liabilities assumed: | | |
| Asset retirement obligations | | (14,564) |
| Accrued liabilities and other | | (10,121) |
| Bargain purchase gain | | (7,651) |
| Total purchase price | $ | 38,606 |

All assets and liabilities associated with Sasol's interest in Etame Marin block, including crude oil, natural gas and NGLs properties, asset retirement obligations and working capital items, were recorded at their fair value. The Company used estimated future crude oil prices as of the closing date, February 25, 2021, to apply to the estimated reserve quantities acquired and market participant assumptions to the estimated future operating and development costs to arrive at the estimates of future net revenues. The future net revenues were discounted using the Company's weighted average cost of capital to determine the fair value at closing. The valuations to derive the purchase price included the use of both proved and unproved categories of reserves, expectation for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates, and risk adjusted discount rates. Other significant estimates were used by the Company to determine the fair value of assets acquired and liabilities assumed. As a result of comparing the purchase price to the fair value of the assets acquired and liabilities assumed a $7.7 million bargain purchase gain was recognized. A bargain purchase gain of $5.2 million is included in "Other income (expense), net" in the consolidated statements of operations and comprehensive income (loss). An income tax benefit of $4.1 million, related to the bargain purchase gain, is also included in the consolidated statements of operations and comprehensive income (loss). The bargain purchase gain is primarily attributable to the increase in crude oil price forecasts from the date the SPA was signed, November 17, 2020, to the closing date, February 25, 2021, when the fair value of the reserves associated with the Sasol Acquisition were determined.

Under the terms of the SPA, a contingent payment of $5.0 million was payable to Sasol should the average Dated Brent price over a consecutive 90-day period from July 1, 2020 to June 30, 2022 exceed $60.00 per barrel. Included in the purchase consideration was the fair value, at closing, of the contingent payment due to Sasol. The conditions related to the contingent payment were met and on April 29, 2021, the Company paid the $5.0 million contingent amount to Sasol in accordance with the terms of the SPA.

For the twelve months ended December 31, 2021, included in the line item "Other income (expense), net" is $1.0 million of transaction fees associated with the Sasol Acquisition.

The impact of the Sasol Acquisition was an increase to "Crude oil, natural gas and NGLs sales" of $144.8 million and $14.6 million of "Net income" in the consolidated statements of operations and comprehensive income (loss) for the year ended December 31, 2022. The impact of the Sasol Acquisition was an increase to "Crude oil, natural gas and NGLs sales" of $84.6 million and $29.3 million of "Net income" in the consolidated statements of operations and comprehensive income (loss) for the year ended December 31, 2021.

The unaudited pro forma results presented below have been prepared to give the effect to the Sasol Acquisition discussed above on the Company's results of operations for the years ended December 31, 2022 and 2021, as if the Sasol Acquisition had been consummated on January 1, 2020. In addition the unaudited pro forma results presented below have been prepared to give the effect to the TransGlobe Arrangement discussed above on the Company's results of operations for the years ended December 31, 2022 and 2021, as if the Arrangement had been consummated on January 1, 2021. The unaudited pro forma results do not purport to represent what the Company's actual results of operations would have been if the Sasol Acquisition or TransGlobe Arrangement 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, 2022 | | Year Ended December 31, 2021 | |
|---|---|---|---|---|
| | (in thousands) | | | |
| Pro forma (unaudited) | | | | |
| Crude oil and natural gas sales | $ 547,670 | **(a)** | $ 367,210 | **(a)** |
| Operating income | $ 267,582 | **(b)** | $ 104,924 | **(c)** |
| Net income | $ 130,425 | **(d)** | $ 54,534 | **(e,f)** |
| | | | | |
| Basic net income per share: | | | | |
| Income from continuing operations | $ 1.21 | | $ 0.51 | |
| Loss from discontinued operations, net of tax | - | | - | |
| Net income per share | $ 1.21 | | $ 0.51 | |
| Basic weighted average shares outstanding | 108,206 | | 107,537 | |
| Diluted net income per share: | | | | |
| Income from continuing operations | $ 1.20 | | $ 0.50 | |
| Loss from discontinued operations, net of tax | - | | - | |
| Net income per share | $ 1.20 | | $ 0.50 | |
| Diluted weighted average shares outstanding | 108,642 | | 108,062 | |

(a) The unaudited pro forma net revenues associated with Crude oil, natural gas and natural gas liquids sales have been adjusted for shipping and handling costs based on the Company's historical policy and revenue recognition is based on the Company's working interest, less royalties, the entitlement method.

(b) The unaudited pro forma operating income for the year ended December 31, 2022 removes the $23.7 million impairment reversal recorded by TransGlobe in 2022, excludes $10.2 million of severance costs associated with the Arrangement, excludes $6.5 million of TransGlobe transaction costs associated with the Arrangement, reclassifies depreciation expense, for certain leases identified as operating leases, to production expense and adjusts depreciation, depletion and amortization expense related to the depletable assets and asset retirement obligations acquired in the Arrangement based on the purchase price allocation.

(c) The unaudited pro forma operating income for the year ended December 31, 2021 removes the $31.5 million impairment reversal recorded by TransGlobe in 2021, adjusts costs associated with overlifts to reduce revenue, includes $10.2 million of severance costs associated with the Arrangement, reclassifies depreciation expense, for certain leases identified as operating leases, to production expense and adjusts depreciation, depletion and amortization expense related to the depletable assets and asset retirement obligations acquired in the Arrangement based on the purchase price allocation.

(d) The unaudited pro forma net income for the year ended December 31, 2022 excludes $14.6 million of transaction costs incurred by VAALCO associated with the Arrangement, excludes the bargain purchase gain of $10.8 million and reclassifies interest expense, for certain leases identified as operating leases, as production expense.

(e) The unaudited pro forma net income for the year ended December 31, 2021 includes $21.1 million of transaction costs incurred by VAALCO and TransGlobe associated with the Arrangement, includes the bargain purchase gain of $10.8 million and reclassifies interest expense, for certain leases identified as operating leases, as production expense.

(f) The unaudited pro forma net income for the year ended December 31, 2021 excludes nonrecurring pro forma adjustments directly attributable to the Sasol Acquisition, consisting of a bargain purchase gain of $7.7 million and transaction costs of $1.0 million

***Discontinued Operations - Angola and Yemen***

In November 2006, the Company signed a production sharing contract for Block 5 offshore Angola ("Block 5 PSA"). The Company's working interest was 40%, and the Company carried Sonangol P&P, for 10% of the work program. On September 30, 2016, the Company notified Sonangol P&P that it was withdrawing from the joint operating agreement effective October 31, 2016. On November 30, 2016, the Company notified the national concessionaire, Sonangol E.P., that it was withdrawing from the Block 5 PSA and reduced its activities in Angola. As a result of this strategic shift, the Company classified all the related assets and liabilities as those of discontinued operations in the consolidated balance sheets. The operating results of the Angola segment have been classified as discontinued operations for all periods presented in the Company's consolidated statements of operations and comprehensive income (loss). The Company segregated the cash flows attributable to the Angola segment from the cash flows from continuing operations for all periods presented in the Company's consolidated statements of cash flows. During the year ended December 31, 2022 and 2021, the Angola segment did not have a material impact on the Company's financial position, results of operations, cash flows and related disclosures.

As part of the Arrangement with TransGlobe, the Company acquired TG Holdings Yemen Inc. who previously owned TransGlobe's interests in four PSAs in Yemen: Block 32, Block 72, Block 75 and Block S-1. In January 2015, TransGlobe relinquished its interests in Block 32 and Block 72 in Yemen (effective dates of March 31, 2015 and February 28, 2015, respectively), and in October 2015 TransGlobe sold its subsidiary that held interests in Block 75 and Block S-1. The operating results of the Yemen segment have been classified as discontinued operations for all periods presented in the Company's consolidated statements of operations and comprehensive income (loss). The Company segregated the cash flows attributable to the Yemen segment from the cash flows from continuing operations for all periods presented in the Company's consolidated statements of cash flows. During the year ended December 31, 2022, the Yemen segment did not have a material impact on the Company's financial position, results of operations, cash flows and related disclosures.

## 5. SEGMENT INFORMATION

The Company's operations are based in Gabon, Egypt, 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 evaluates the operation of each geographic segment separately primarily based on Operating income (loss). 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. No transactions occurred between segments.

Segment activity of continuing operations for the years ended December 31, 2022, 2021 and 2020 and long-lived assets and segment assets at December 31, 2022 and 2021 are as follows:

| | Year ended December 31, 2022 | | | | | |
|---|---|---|---|---|---|---|
| *(in thousands)* | Gabon | Egypt | Canada | Equatorial Guinea | Corporate and Other | Total |
| Revenues: | | | | | | |
| Crude oil, natural gas and natural gas liquids sales | $ 306,775 | $ 37,710 | $ 9,841 | $ — | $ — | $ 354,326 |
| Operating costs and expenses: | | | | | | |
| Production expense | 96,854 | 11,936 | 1,972 | 1,899 | — | 112,661 |
| FPSO demobilization | 8,867 | — | — | — | — | 8,867 |
| Exploration expense | 258 | — | — | — | — | 258 |
| Depreciation, depletion and amortization | 34,651 | 10,444 | 2,921 | — | 127 | 48,143 |
| General and administrative expense | 3,101 | — | — | 538 | 6,438 | 10,077 |
| Bad debt expense and other | 2,743 | — | — | 339 | — | 3,082 |
| Total operating costs and expenses | 146,474 | 22,380 | 4,893 | 2,776 | 6,565 | 183,088 |
| Other operating income, net | 38 | — | — | — | — | 38 |
| Operating income (loss) | 160,339 | 15,330 | 4,948 | (2,776) | (6,565) | 171,276 |
| Other income (expense): | | | | | | |
| Derivative instruments gain (loss), net | — | — | 13 | — | (37,825) | (37,812) |
| Interest (expense) income, net | (1,446) | (596) | — | — | 8 | (2,034) |
| Other expense, net | (1,484) | — | — | — | (6,564) | (8,048) |
| Total other Income (expense), net | (2,930) | (596) | 13 | — | (44,381) | (47,894) |
| Income (loss) from continuing operations before income taxes | 157,409 | 14,734 | 4,961 | (2,776) | (50,946) | 123,382 |
| Income tax (benefit) expense | 68,509 | 6,254 | — | 1 | (3,344) | 71,420 |
| Income (loss) from continuing operations | 88,900 | 8,480 | 4,961 | (2,777) | (47,602) | 51,962 |
| Loss from discontinued operations, net of tax | — | — | — | — | (72) | (72) |
| Net income (loss) | $ 88,900 | $ 8,480 | $ 4,961 | $ (2,777) | $ (47,674) | $ 51,890 |
| Consolidated capital expenditures [(1)] | $ 162,375 | $ 168,012 | $ 103,263 | $ — | $ 710 | $ 434,360 |

(1) - Includes assets acquired in the TransGlobe acquisition

| *(in thousands)* | Year Ended December 31, 2021 Gabon | Equatorial Guinea | Corporate and Other | Total |
|---|---|---|---|---|
| Revenues: | | | | |
| Crude oil and natural gas sales | $ 199,075 | $ — | $ — | $ 199,075 |
| Operating costs and expenses: | | | | |
| Production expense | 80,717 | 532 | 6 | 81,255 |
| Exploration expense | 1,579 | — | — | 1,579 |
| Depreciation, depletion and amortization | 20,972 | — | 88 | 21,060 |
| General and administrative expense | 1,301 | 321 | 13,144 | 14,766 |
| Bad debt expense and other | 875 | - | — | 875 |
| Total operating costs and expenses | 105,444 | 853 | 13,238 | 119,535 |
| Other operating expense, net | (440) | — | — | (440) |
| Operating income | 93,191 | (853) | (13,238) | 79,100 |
| Other income (expense): | | | | |
| Derivative instruments loss, net | — | — | (22,826) | (22,826) |
| Interest income, net | — | — | 10 | 10 |
| Other (expense) income, net | 6,925 | (3) | (3,428) | 3,494 |
| Total other income (expense), net | 6,925 | (3) | (26,244) | (19,322) |
| Income (loss) from continuing operations before income taxes | 100,116 | (856) | (39,482) | 59,778 |
| Income tax (benefit) expense | 12,392 | 1 | (34,549) | (22,156) |
| Income (loss) from continuing operations | 87,724 | (857) | (4,933) | 81,934 |
| Loss from discontinued operations, net of tax | — | — | (98) | (98) |
| Net income (loss) | $ 87,724 | $ (857) | $ (5,031) | $ 81,836 |
| Consolidated capital expenditures (1) | $ 79,169 | $ — | $ 52 | $ 79,221 |

(1) Includes assets acquired in the Sasol acquisition.

| *(in thousands)* | Year Ended December 31, 2020 Gabon | Equatorial Guinea | Corporate and Other | Total |
|---|---|---|---|---|
| Revenues: | | | | |
| Crude oil and natural gas sales | $ 67,176 | $ — | $ — | $ 67,176 |
| Operating costs and expenses: | | | | |
| Production expense | 37,298 | 1 | 16 | 37,315 |
| Exploration expense | 3,588 | — | — | 3,588 |
| Depreciation, depletion and amortization | 9,028 | — | 354 | 9,382 |
| Impairment of proved crude oil and natural gas properties | 30,625 | — | — | 30,625 |
| General and administrative expense | 1,064 | 430 | 9,201 | 10,695 |
| Bad debt expense and other | 1,165 | — | — | 1,165 |
| Total operating costs and expenses | 82,768 | 431 | 9,571 | 92,770 |
| Other operating expense, net | (1,669) | — | — | (1,669) |
| Operating loss | (17,261) | (431) | (9,571) | (27,263) |
| Other income (expense): | | | | |
| Derivative instruments gain, net | — | — | 6,577 | 6,577 |
| Interest income, net | — | — | 155 | 155 |
| Other (expense) income, net | 194 | 3 | (68) | 129 |
| Total other expense, net | 194 | 3 | 6,664 | 6,861 |
| Loss from continuing operations before income taxes | (17,067) | (428) | (2,907) | (20,402) |
| Income tax expense | 16,204 | 1 | 11,476 | 27,681 |
| Loss from continuing operations | (33,271) | (429) | (14,383) | (48,083) |
| Loss from discontinued operations, net of tax | — | — | (98) | (98) |
| Net loss | $ (33,271) | $ (429) | $ (14,481) | $ (48,181) |
| Consolidated capital expenditures | $ 10,503 | $ — | $ (9) | $ 10,494 |

| *(in thousands)* | Gabon | Egypt | Canada | Equatorial Guinea | Corporate and Other | Total |
|---|---|---|---|---|---|---|
| Long-lived assets from continuing operations: | | | | | | |
| As of December 31, 2022 (1) | **$ 213,204** | **$ 168,012** | **$ 103,263** | **$ 10,000** | **$ 793** | **$ 495,272** |
| As of December 31, 2021 (2) | 84,156 | $ — | $ — | $ 10,000 | $ 168 | $ 94,324 |

(1) - Includes assets acquired in the TransGlobe acquisition
(2) - Includes assets acquired in the Sasol acquisition

| *(in thousands)* | Gabon | Egypt | Canada | Equatorial Guinea | Corporate and Other | Total |
|---|---|---|---|---|---|---|
| Total assets from continuing operations: | | | | | | |
| As of December 31, 2022 (1) | **$ 395,393** | **$ 293,640** | **$ 110,071** | **$ 10,861** | **$ 45,676** | **$ 855,641** |
| As of December 31, 2021 (2) | 201,748 | $ — | $ — | $ 10,548 | $ 50,794 | $ 263,090 |

(1) - Includes assets acquired in the TransGlobe acquisition
(2) - Includes assets acquired in the Sasol acquisition

***Information about the Company's most significant customers***

The Company currently sells crude oil production from Gabon under term crude oil sales and purchase agreements ("COSPAs") or crude oil sales and marketing agreements ("COSMA or COSMAs") with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors.

As discussed further in Note 13, on May 16, 2022, VAALCO Gabon (Etame), Inc. (the "Borrower") entered into a facility agreement (the "Facility Agreement") by and among the Company, VAALCO Gabon, SA ("VAALCO Gabon"), Glencore Energy UK Ltd., as mandated lead arranger, technical bank and facility agent ("Glencore"), the Law Debenture Trust Corporation P.L.C., as security agent, and the other financial institutions named therein (the "Lenders"), providing for a senior secured reserve-based revolving credit facility (the "Facility") in an initial aggregate maximum principal amount available of up to $50.0 million. In connection with the entry into the Facility Agreement, the Company entered into a COSMA with Glencore pursuant to which the Company agreed to make Glencore the exclusive offtaker and marketer of all of the crude oil produced from the Etame G4-160 Block, offshore Gabon during the period from August 1, 2022 until the final maturity date of the Facility (as defined in the Facility Agreement) which is May 15, 2027 unless early terminated. Pursuant to the COSMA, Glencore agreed to buy and market the Company's crude oil with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors.

From February 2019 through January 2020, crude oil sales were to Mercuria Energy Trading SA ("Mercuria"). The Company entered an COSPA and amendments with ExxonMobil that covered sales from February 2020 through July 2022 with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors.

For the year ended December 31, 2022, Etame revenues from the sales of crude oil to Exxon made up 68% of revenues and sales of crude oil to Glencore made up 32% of revenues. For the period of October 14, 2022 through December 31, 2022, EGPC covered 100% of the Company's crude oil sales in Egypt. For the period of October 14, 2022 through December 31, 2022, revenues in Canada were concentrated in three separate customers that constituted approximately 54%, 32% and 14% of revenues. Concentrations of accounts receivable are similar to the revenue percentages.

## 6. 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, | | |
|---|---|---|---|
| | 2022 | 2021 | 2020 |
| | | (in thousands) | |
| Net income (loss) (numerator): | | | |
| Income (loss) from continuing operations | **$ 51,962** | $ 81,934 | $ (48,083) |
| Income from continuing operations attributable to unvested shares | **(594)** | (1,336) | — |
| Numerator for basic | **51,368** | 80,598 | (48,083) |
| Loss from continuing operations attributable to unvested shares | **3** | — | — |
| Numerator for dilutive | **$ 51,371** | $ 80,598 | $ (48,083) |
| Loss from discontinued operations, net of tax | **$ (72)** | $ (98) | $ (98) |
| Loss from discontinued operations attributable to unvested shares | **1** | 2 | — |
| Numerator for basic | **(71)** | (96) | (98) |
| (Income) loss from discontinued operations attributable to unvested shares | — | — | — |
| Numerator for dilutive | **$ (71)** | $ (96) | $ (98) |
| Net income (loss) | **$ 51,890** | $ 81,836 | $ (48,181) |
| Net income attributable to unvested shares | **(593)** | (1,334) | — |
| Numerator for basic | **51,297** | 80,502 | (48,181) |
| Net (income) loss attributable to unvested shares | **3** | — | — |
| Numerator for dilutive | **$ 51,300** | $ 80,502 | $ (48,181) |
| Weighted average shares (denominator): | | | |
| Basic weighted average shares outstanding | **69,568** | 58,230 | 57,594 |
| Effect of dilutive securities | **414** | 525 | — |
| Diluted weighted average shares outstanding | **69,982** | 58,755 | 57,594 |
| Stock options and unvested restricted stock grants excluded from dilutive calculation because they would be anti-dilutive | **189** | 169 | 3,545 |

## 7. REVENUE

***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"). COSPAs and COSMAs with customers are renegotiated near the end of the contract term and may be entered into with a different customer or the same customer going forward. Except for internal costs, which are expensed as incurred, there are no upfront costs associated with obtaining a new COSPA or COSMA. See Note 5 under "*Information about the Company's most significant customers*" for further discussion.

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 intervals between liftings are generally one month; however, changes in the timing of liftings will impact the number of liftings that occur during the period. Therefore, the performance obligation attributable to volumes to be sold in future liftings are wholly unsatisfied, and there is no transaction price allocated to remaining performance obligations. 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.

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. However, under the COSMA, each coventurer is responsible for invoicing Glencore their respective ownership interest in the final volumes.

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.

Generally, no significant judgments or estimates are required as of a given filing date with regard to applicable price or volumes sold because all of the parameters are known with certainty related to liftings that occurred in the recently completed calendar quarter. As such, the Company deemed this situation to be characterized as a fixed price situation.

In addition to revenues from customer contracts, the Company has other revenues related to contractual provisions under the Etame Marin block PSC. The Etame PSC is not a customer contract, and therefore the associated revenues are not within the scope of ASC 606. 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. Should the government elect to take the production attributable to its royalty in-kind, the Company would no longer have sales to customers associated with production assigned to royalties.

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. Prior to February 1, 2018, the government did not take any of its share of Profit Oil in-kind. These revenues have been included in revenues to customers as the Company entered into the contract with the customer to sell the crude oil and was subject to the performance obligations associated with the contract. For the in-kind sales by the government beginning February 1, 2018, these sales are not considered revenues under a customer contract as the Company is not a party to the contracts with the buyers of this crude oil. However, consistent with the reporting of Profit Oil in prior periods, 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, *i.e.* the period in which it lifts the crude oil. An in-kind payment of $26.3 million was made with the December 2022 lifting. With this lifting, the government lifted more oil in-kind than what was owed to it in foreign taxes. Therefore, the Company has a $2.8 million foreign income tax receivable as of December 31, 2022. As of December 31, 2021, the foreign income taxes payable attributable to this obligation was $3.1 million.

Certain amounts associated with the carried interest in the Etame Marin block discussed above 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, | | |
|---|---|---|---|
| | **2022** | **2021** | **2020** |
| | | *(in thousands)* | |
| Revenues from customer contracts: | | | |
| Sales under the COSPA or COSMA | **$ 320,522** | $ 200,321 | $ 67,041 |
| Other items reported in revenue not associated with customer contracts: | | | |
| Gabonese government share of Profit Oil taken in-kind | **26,257** | 20,103 | 8,738 |
| Carried interest recoupment | **5,843** | 7,517 | 1,631 |
| Royalties | **(45,847)** | (28,866) | (10,234) |
| Crude oil and natural gas sales | **$ 306,775** | $ 199,075 | $ 67,176 |

***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’s subsidiary, TransGlobe Petroleum International (“TPI”), each own a 50% interest, respectively, in the operating company which is a party to the Merged Concession Agreement. EGPC and the Company’s subsidiary, TPI, each also own a 50% interest, respectively, in the operating company that is a party to the South Ghazalat concession agreement. 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.

Customer sales generally occur on a daily basis when sales are directly to EGPC or haphazardly production is sold through a cargo lifting. Direct sales to EGPC are considered complete when oil is delivered to EGPC storage facility. When sales are made through cargo lifting, the performance obligations are normally satisfied either when the oil is delivered to the export facility location or when the oil is delivered to its ultimate destination, as specified in the contract. Regardless of the type of sales, there is a single performance obligation (delivering crude oil to the delivery point) that gives rise to revenue recognition at the point in time when the performance obligation event takes place. 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.

Revenues associated with the sales of the Company’s crude oil in Egypt are recognized by reference to actual volumes sold and quoted market prices in active markets for Dated Brent, 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. For reporting purposes, 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 which is discussed below.

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 Company'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. 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-sharing oil. During times of lower oil prices, the Company receives more cost oil and may receive less profit oil. EGPC’s share of production_will increase during times of rising oil prices and decrease in times of declining oil prices. If oil prices are sufficiently low and the Gharib Blend/Dated Brent differential is high, the cost oil portion may not be sufficient to cover operating costs and capital costs, or even operating costs alone. When this occurs, the non-recovered costs accumulate in the Company’s cost pools and are available to be offset against future cost oil during the term of the PSCs and any eligible extension periods.

With respect to Egyptian income taxes, which are the Company’s liability under the terms of the Merged Concession Agreement, 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 for reporting purposes.

EGPC owns the storage and export facilities where the Company's production is delivered and the Company requires EGPC 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. Direct sales to EGPC are normally settled two to four weeks from delivery.

In some instances TPI will borrow or loan production volumes in order to achieve a required amount of crude oil for cargo sales. In these instances TPI can be in an overlift or underlift position. Regardless of being in an over lift or underlift position, sales are based on the Company’s working interest, less royalties. Imbalances are valued based on the actual sales proceeds and TPI 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:

| | October 14 - December 31, 2022 |
|---|---|
| | **Sales** |
| Revenues from customer contracts: | ***(in thousands)*** |
| Gross sales | **$ 56,452** |
| Royalties | **(18,742)** |
| Net revenues | **$ 37,710** |

***Canada***

Revenues from the sale of crude oil, natural gas, condensate and natural gas liquids ("NGLs") in Canada are recognized by reference to actual volumes delivered at contracted delivery points and prices. 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. Prices are determined by reference to quoted market prices in active markets for crude oil, natural gas, condensate, and NGLs based on product, each adjusted according to specific terms and conditions applicable per the sales contracts. Revenues are measured at the transaction price that the Company expects to be entitled in exchange for transferring promised goods to a customer and is determined based at the fair value of the consideration received. VAALCO pays royalties to the Alberta provincial government and other mineral rights owners in accordance with the established royalty regime. For reporting purposes, the Company records revenues net of royalties.

Customer sales generally occur on a daily basis when crude oil, natural gas, condensate or NGL's are sold, normally via pipeline, to a delivery point. Regardless of the type of sales, 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. 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.

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

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

| | October 14 - December 31, 2022 |
|---|---|
| | **Sales** |
| Revenues from customer contracts: | ***(in thousands)*** |
| Oil revenue | **$ 7,362** |
| Gas revenue | **1,340** |
| NGL revenue | **2,235** |
| Condensate revenue | **7** |
| Other revenue | **34** |
| Royalties | **(1,137)** |
| Net revenues | **$ 9,841** |

## 8. INCOME TAXES

VAALCO and its domestic subsidiaries file a consolidated U.S. income tax return. Certain foreign subsidiaries also file tax returns in their respective local jurisdictions that include Canada, Egypt, Equatorial Guinea and Gabon.

Income taxes attributable to continuing operations for the year ended December 31, 2022 are attributable to foreign taxes payable in Gabon and Egypt whereas for the years ended December 31, 2021 and 2020 the income taxes are attributable to foreign taxes payable in Gabon as well as income taxes in the U.S.

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2022** | **2021** | **2020** |
| | | *(in thousands)* | |
| U.S. Federal: | | | |
| Current | $ — | $ — | $ (337) |
| Deferred | **(3,344)** | (34,548) | 11,814 |
| Foreign: | | | |
| Current | **26,615** | 20,282 | 3,859 |
| Deferred | **48,149** | (7,890) | 12,345 |
| Total | **$ 71,420** | $ (22,156) | $ 27,681 |

As of December 31, 2022 the Company had total deferred tax assets of $99.6 million primarily attributable to Canada, Gabon and the U.S. whereas for December 31, 2021 deferred tax assets were $86.9 million primarily attributable to Gabon and U.S. In both years, the income taxes related to basis differences in fixed assets, foreign tax credit carryforwards, as well as U.S. and foreign net operating loss carryforwards. In assessing the realizability of the deferred tax assets, the Company considers all available positive and negative evidence by jurisdiction and makes a determination whether it is more likely than not that some or all of the deferred tax assets will be realized. 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.

As of December 31, 2022, due to a positive outlook regarding future taxable income, the Company determined that it is more likely than not that it would be able to utilize a large portion of its U.S deferred tax assets. Additionally, the Company also determined that it is more likely than not that it would not be able to utilize its deferred tax assets in Canada and in Egypt for its South Ghazalat concession. As of December 31, 2021, the Company determined that it is more likely than not that it would not be able to utilize its deferred tax assets. On the basis of these evaluations, a valuation allowance of $47.6 million and $46.9 million were recorded as of December 31, 2022 and 2021, respectively. Valuation allowances reduce the deferred tax assets to the amount that is more likely than not to be realized.

The primary differences between the financial statement and tax bases of assets and liabilities resulted in deferred tax assets associated with continuing operations at December 31, 2022 and 2021 are as follows:

| | As of December 31, | |
|---|---|---|
| ***(in thousands)*** | **2022** | **2021** |
| Deferred tax assets: | | |
| Basis difference in fixed assets | **$ 9,299** | $ 20,133 |
| Foreign tax credit carryforward | **14,848** | 20,084 |
| Net operating losses | **48,981** | 25,182 |
| Foreign deferred tax assets, net of impact on U.S. taxes | **—** | 8,693 |
| Asset retirement obligations | **8,531** | 8,546 |
| Operating lease liabilities | **10,753** | **1,750** |
| Basis difference in accrued liabilities | **3,800** | 402 |
| Basis difference in receivables | **2,783** | 454 |
| Other | **622** | 1,683 |
| Total deferred tax assets | **99,617** | 86,927 |
| Valuation allowance | **(47,583)** | (46,949) |
| Net deferred tax assets | **$ 52,034** | $ 39,978 |
| | | |
| Deferred tax liabilities: | | |
| Basis difference in fixed assets | **(97,825)** | — |
| Net deferred tax liabilities | **$ (97,825)** | $ — |

Foreign net operating losses ("NOLs") are subject to varying expiration periods depending on the jurisdiction. The NOLs for the Gabon subsidiaries are included in the respective subsidiaries' cost oil accounts, which will be offset against future taxable revenues and do not expire. U.S. federal NOLs incurred after 2017 do not expire. The ability to utilize NOLs and other tax attributes could be subject to a limitation if the Company were to undergo an ownership change as defined in Section 382 of the Tax Code. Foreign tax credits will expire between the years 2024 and 2032. The Company does not anticipate utilization of the foreign tax credits prior to expiration and has recorded a full valuation allowance on these deferred tax assets.

The Company has NOL's, *(in '000s)* in the following jurisdictions as of December 31, 2022:

| **Jurisdiction** | **Amount** | **Expiration Period** |
|---|---|---|
| U.S. | $ 45,498 | No expiration |
| Gabon | $ 37,983 | No expiration |
| Egypt | $ 14,558 | 2023-2027 |
| Canada | $ 130,542 | 2024-2042 |

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, 2022 and 2021. The Company's policy is to include interest and penalties related to unrecognized tax benefits as a component of income tax expense.

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

| *(in thousands)* | Year Ended December 31, 2022 | 2021 | 2020 |
|---|---|---|---|
| U.S. | **$ (56,750)** | $ (38,867) | $ (2,908) |
| Foreign | **180,132** | 98,645 | (17,494) |
| | **$ 123,382** | $ 59,778 | $ (20,402) |

The reconciliation of income tax expense (benefit) attributable to income (loss) from continuing operations to income tax on income (loss) from continuing operations at the U.S. statutory rate is as follows:

| *(in thousands)* | Year Ended December 31, 2022 | 2021 | 2020 |
|---|---|---|---|
| Tax provision computed at U.S. statutory rate | **$ 25,910** | $ 12,553 | $ (4,284) |
| Foreign taxes not offset in U.S. by foreign tax credits | **53,851** | 35,306 | (9,801) |
| Permanent differences | **778** | (703) | 97 |
| Foreign tax credit expirations | **17,247** | 14,060 | — |
| Increase/(decrease) in valuation allowance | **(25,623)** | (83,372) | 41,635 |
| Other | **(743)** | — | 34 |
| Total income tax expense (benefit) | **$ 71,420** | $ (22,156) | $ 27,681 |

For the years ended December 31, 2022, 2021 and 2020, 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. | 2014-2022 |
| Gabon | 2018-2022 |
| Egypt | 2017-2022 |
| Canada | 2018-2022 |

With respect to the earnings of VAALCO's Canadian foreign subsidiary, the Company does not intend to repatriate funds and will indefinitely reinvest these foreign earnings. Determining the amount of the unrecorded deferred tax liability related to temporary differences at this time is not practicable. If circumstances change and it becomes apparent that some or all the undistributed earnings of our Canadian subsidiary will be remitted in the foreseeable future, the Company shall accrue as an expense of the current period income taxes attributable to that remittance.

With respect to the earnings of VAALCO's Egyptian foreign subsidiaries, the earnings are available for repatriation, but the corresponding incremental tax expense on any remittances is not expected to be material.

On August 16, 2022, legislation commonly known as the Inflation Reduction Act was signed into law. Among other things, the Inflation Reduction Act includes a 1% excise tax on corporate stock repurchases (applicable to repurchases after December 31, 2022) as well as a new minimum tax based on book income. While the Inflation Reduction Act did not have a material impact on its effective tax rate in 2022, the analysis of the impact of the Inflation Reduction Act on the Company is ongoing.

## 9. CRUDE OIL, NATURAL GAS and NGLs PROPERTIES AND EQUIPMENT

The Company's crude oil, natural gas and NGLs properties and equipment is comprised of the following:

| | **As of December 31, 2022** | **As of December 31, 2021** |
|---|---|---|
| | *(in thousands)* | |
| Crude oil and natural gas properties and equipment - successful efforts method: | | |
| Wells, platforms and other production facilities | **$ 1,406,888** | $ 488,756 |
| Work-in-progress | **—** | 13,515 |
| Undeveloped acreage | **56,251** | 23,735 |
| Equipment and other | **38,796** | 23,478 |
| | **1,501,935** | 549,484 |
| Accumulated depreciation, depletion, amortization and impairment | **(1,006,663)** | (455,160) |
| Net crude oil and natural gas properties, equipment and other | **$ 495,272** | $ 94,324 |

***Extension of Term of Etame Marin Block PSC***

On September 25, 2018, VAALCO, together with the other joint venture owners in the Etame Marin block (the "Etame Consortium"), received an implementing Presidential Decree from the government of Gabon authorizing the PSC Extension to the Etame Consortium to operate in the Etame Marin block. The Company's subsidiary, VAALCO Gabon S.A., currently has a 63.575% participating interest (working interest including the working interest attributable to the carried interest owner) in the Etame Marin block.

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. Prior to the PSC Extension, the exploitation periods for the three exploitation areas in the Etame Marin block would expire beginning in June 2021. The PSC Extension also grants the Etame Consortium the right for two additional extension periods of five years each. The PSC Extension further allows the Etame Consortium to explore the potential for resources within the area of each Exclusive Exploitation Authorization as defined in the PSC Extension.

In consideration for the PSC Extension, the Etame Consortium agreed to a signing bonus of $65.0 million ($21.8 million, net to VAALCO) payable to the government of Gabon (the "signing bonus"). The Etame Consortium paid $35.0 million ($11.8 million, net to VAALCO) in cash on September 26, 2018 and paid $25.0 million ($8.4 million, net to VAALCO) through an agreed upon reduction of the VAT receivable owed by the government of Gabon to the Etame Consortium as of the effective date. An additional $5.0 million ($1.7 million, net to VAALCO) was paid in cash by the Etame Consortium following the end of the drilling activities described below.

As required under the PSC Extension, the Etame Consortium completed drilling two development wells and two appraisal wellbores during the 2019/2020 drilling campaign with the last appraisal wellbore completed in February 2020. During September 2020, the Etame Consortium completed the two technical studies at a cost of $1.5 million gross ($0.5 million, net to VAALCO).

In accordance with the Etame Marin block PSC, the Etame Consortium maintains a "Cost Account," which accumulates capital costs and operating expenses that are deductible against revenues, net of royalties, in determining taxable profits. Under the PSC Extension, the Cost Recovery Percentage 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%. The government of Gabon will acquire from the Etame Consortium an additional 2.5% gross working interest carried by the Etame Consortium effective June 20, 2026. VAALCO's share of this interest to be transferred to the government of Gabon is 1.6%.

***Proved Properties***

The Company reviews 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. The fair value of the asset is measured using a discounted cash flow model relying primarily on Level 3 inputs into the undiscounted future net cash flows. The undiscounted estimated future net cash flows used in the impairment evaluations at each quarter end are based upon the most recently prepared independent reserve engineers' report adjusted to use forecasted prices from the forward strip price curves near each quarter end and adjusted as necessary for drilling and production results.

There was no triggering event in the year ended December 31, 2022 that would cause the Company to believe the value of crude oil, natural gas and NGLs producing properties should be impaired. Factors considered included higher forward price curves for the fourth quarter of 2022 and capital expenditures in the period related to its reserves in Gabon, Egypt and Canada.

Declining forecasted oil prices in the first quarter of 2020 caused the Company to perform an impairment review during this period. The impairment test was performed using the year end 2019 independently prepared reserve report, estimated reserves for the South East Etame 4H well completed in March 2020 and forward price curves. The Company performed a recoverability test as defined under ASC 932 and ASC 360, noting that the undiscounted cash flows related to the Etame Marin block were less than the book value for the block, resulting in the Company recording a $30.6 million impairment loss to write down the Company’s investment to its fair value of $15.6 million.

***Undeveloped Leasehold Costs***

VAALCO acquired a 31% working interest in an undeveloped portion of a block (“Block P”) offshore Equatorial Guinea in 2012. The Ministry of Mines and Hydrocarbons (“EG MMH”) approved the Company's appointment as the operator of Block P on November 12, 2019. The Company acquired an additional working interest of 12% from Atlas Petroleum, thereby increasing its working interest to 43% in 2020, in exchange for a potential future payment of $3.1 million to Compania Nacional de Petroles de Guinea Equitoria, (“GEPetrol”) in the event that there is commercial production from Block P. On August 27, 2020, the amendment to the production sharing contract to ratify the Company’s increased working interest and appointment as operator was approved by the EG MMH. In April 2021, Crown Energy, who held a 5% working interest elected to default on its obligations of Block P. On April 12, 2021, the non-defaulting parties assigned the defaulting party’s interest to the non-defaulting parties as required by the Joint Operating Agreement. As a result, VAALCO’s working interest increased to 45.9% when the EG MMH approved the fourth amendment to the production sharing contract. As of December 31, 2022, the Company had $10.0 million recorded for the book value of the undeveloped leasehold costs associated with the Block P license. The Company has completed a feasibility study of a standalone development concept of the Venus discovery on Block P. On September 26, 2022, the EG MMH approved the submitted plan of development. Final documents to effect the plan of development are subject to EG MMH approval. The 2023 budget for the plan was delivered on October 12, 2022 to the MMH and was approved effective November 16, 2022. The Block P production sharing contract provides for a development and production period of 25 years from the date of approval of a development and production plan for the area associated with the Venus development. As of December 31, 2022, the Company had $10.0 million recorded for the book value of the undeveloped leasehold costs associated with the Block P license.

In February of 2023, the Company acquired an additional 14.1% participating interest, increasing VAALCO’s participating interest in the Block to 60.0%. In March 2023, Atlas voted to participate in the Venus Development. Amendment 5 of the PSC was approved by all parties in March 2023 with this updated participating interest, and execution of the Venus development plan has been initiated. This increase of 14.1% participating interest increases the Company's future payment to GEPetrol to $6.8 million at first commercial production of the Block.

As a result of the PSC Extension discussed above, the exploitation area for the Etame Marin block was expanded to include previously undeveloped acreage. The Company allocated $6.7 million of the share of the signing bonus and $7.1 million of the $18.6 million resulting from the deferred tax impact for the difference between book basis and tax basis to unproved leasehold costs using the acreage attributable to the previous exploitation areas and the additional acreage in the expanded exploitation areas. Exploitation of this additional area is permitted throughout the term of the Etame Marin block PSC. As a result of discovering reserves in connection with drilling the South East Etame 4H development well in March 2020, $2.3 million of costs were transferred to proved leasehold costs leaving a remaining $11.5 million in unproved leasehold costs. In connection with the Sasol Acquisition discussed under Note 4, $2.2 million of reserves were attributed to undeveloped properties. The balance of undeveloped leasehold costs related to the Etame Marin block at December 31, 2021 was $13.7 million.

In connection with the TransGlobe acquisition discussed under Note 4, $30.2 million of reserves were attributed to undeveloped properties and leasehold costs.

***Capitalized Equipment Inventory***

Capitalized equipment inventory is reviewed regularly for obsolescence. Adjustments for inventory obsolescence are recorded in the “Other operating income (expense), net” line item of the consolidated statements of operations and comprehensive income (loss). During the years ended December 31, 2022, 2021 and 2020, adjustments for inventory obsolescence were not material.

## 10. DERIVATIVES AND FAIR VALUE

The Company uses derivative financial instruments from time to time to achieve a more predictable cash flow from crude oil production by reducing the exposure to price fluctuations. See Note 2 for further information.

***Commodity swaps***

On January 22, 2021, the Company entered into commodity swaps at a Dated Brent weighted average of $53.10 per barrel for the period from and including February 2021 through January 2022 for a quantity of 709,262 barrels. On May 6, 2021, the Company entered into commodity swaps at a Dated Brent weighted average price of $66.51 per barrel for the period from and including May 2021 through October 2021 for a quantity of 672,533 barrels. On August 6, 2021, the Company entered into additional commodity swaps at a Dated Brent weighted average price of $67.70 per barrel for the period from and including November 2021 through February 2022 for a quantity of 314,420 barrels. On September 24, 2021, the Company entered into additional commodity swaps at a Dated Brent weighted average price of $72.00 per barrel for the period from and including March 2022 to June 2022 for a quantity of 460,000 barrels. See the table below for the unexpired swaps as of December 31, 2022.

On October 26, 2022, the Company entered into additional derivatives contracts for the first quarter of 2023. The details are in the chart below:

| Settlement Period | Type of Contract | Index | Average Monthly Volumes (Bbls) | Weighted Average Put Price (per Bbl) | Weighted Average Call Price (per Bbl) |
|---|---|---|---|---|---|
| January 2023 to March 2023 ... | Collars | Dated Brent | 101,000 | $ 65.00 | $ 120.00 |

While these derivative instruments are intended to be an economic hedge to mitigate the impact of a decline in crude oil prices, the Company has not elected hedge accounting. The contracts are being measured at fair value each period, with changes in fair value recognized in net income. The Company does not enter into derivative instruments for speculative or trading proposes. In connection with the RBL facility entered in May 2022, the Company is required to hedge a portion of its anticipated oil production at the time the Company draws down on the borrowing base.

The derivative instruments are measured at fair value using the Income Method. Level 2 observable inputs used in the valuation model include market information as of the reporting date, such as prevailing Brent crude futures prices, Brent crude futures commodity price volatility and interest rates. The determination of the derivative instrument contracts' fair value includes the impact of the counterparty's non-performance risk.

To mitigate counterparty risk, the Company enters into such derivative contracts with creditworthy financial institutions deemed by management as competent and competitive market makers.

At times, the Company's counterparties require that it post collateral for changes in the net fair value of the derivative contracts. This cash collateral is reported in the line item "Restricted cash" on the condensed consolidated balance sheets.

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

| Derivative Item | Statement of Operations Line | Year Ended December 31, 2022 | 2021 | 2020 |
|---|---|---|---|---|
| | | *(in thousands)* | | |
| Commodity derivatives | Cash settlements paid on matured derivative contracts, net | $ **(42,935)** | $ (18,020) | $ 7,216 |
| | Unrealized gain (loss) | **5,123** | (4,806) | (639) |
| | Derivative instruments gain (loss), net | $ **(37,812)** | $ (22,826) | $ 6,577 |

***Subsequent Event***

The Company entered into additional derivative contracts for the second and third quarters of 2023. The details are in the chart below:

| Settlement Period | Type of Contract | Index | Average Monthly Volumes (Bbls) | Weighted Average Put Price (per Bbl) | Weighted Average Call Price (per Bbl) |
|---|---|---|---|---|---|
| April 2023 to June 2023 | Collars | Dated Brent | 95,500 | $ 65.00 | $ 100.00 |
| July 2023 to September 2023 | Collars | Dated Brent | 95,500 | $ 65.00 | $ 96.00 |

## 11. ASSET RETIREMENT OBLIGATIONS

The following table summarizes the changes in the Company's asset retirement obligations ("ARO's"):

| *(in thousands)* | As of December 31, 2022 | As of December 31, 2021 |
|---|---|---|
| Beginning balance | **$ 40,694** | $ 17,334 |
| Accretion | **1,958** | 1,627 |
| Additions | **6,134** | 14,564 |
| Revisions | **(43)** | 7,169 |
| Settlements | **(6,577)** | — |
| Foreign currency gain (loss) | **(165)** | |
| Ending balance | **$ 42,001** | $ 40,694 |

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

In connection with the TransGlobe Arrangement in October 2022, as discussed in Note 4, the Company added $6.1 million of ARO for the future abandonment and reclamation costs of the Canadian assets. The Egypt concessions have no ARO.

The Company provides for asset retirement obligations on all of its Canadian operations based on current legislation and industry operating practices. The estimated present value of the asset retirement obligation is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related asset. The estimated ARO liability for Canada includes assumptions of actual costs to abandon and/or reclaim wells and facilities, the time frame in which such costs will be incurred, as well as using inflation factors and discount rates in order to calculate the amount of the ARO liability.

In Egypt, under model concession agreements and the Fuel Material Law, liabilities in respect of decommissioning movable and immovable assets (other than wells) passes to the Egyptian Government through the transfer of ownership from the contractor to the government under the cost recovery process. While the current risk to the Company of becoming liable for decommissioning liabilities in Egypt is low, future changes to legislation could result in decommissioning liabilities in Egypt. Any increase in Egyptian decommissioning liabilities could adversely affect the Company's financial condition.

In relation to petroleum wells, under good oilfield practices, the contractor is responsible for decommissioning non-producing wells under a decommissioning plan approved by EGPC during the life of the concession agreement. If EGPC agrees that a producing well is not economic, then the contractor may be responsible for decommissioning the well under an EGPC approved decommissioning plan. EGPC, at its own discretion, may not require a well to be decommissioned if it wants to preserve the ability to use the well for other purposes. As EGPC has discretion on decommissioning wells, there is a risk that the Company could incur well decommissioning costs. In accordance with the respective concession agreements, expenses approved by EGPC are recoverable through the cost recovery mechanism. At December 31, 2022, no asset retirement obligation is recorded associated with the Egypt PSCs.

With relation to the end of the FPSO contract in October 2022, the Company incurred decommissioning settlement fees totaling $6.6 million previously recorded in the asset retirement obligations and included on the consolidated statements of cash flows in the line item, "Cash settlements paid on asset retirement obligations".

In connection with the Sasol Acquisition in February 2021, as discussed in Note 4, the Company added $14.6 million of asset retirement obligations as a result of increasing its interest in the Etame Marin block in Gabon.

The Company is required under the Etame PSC for the Etame Marin block in Gabon to conduct abandonment studies to update the amounts being funded for the eventual abandonment of the offshore wells, platforms and facilities on the Etame Marin block. The current abandonment study was prepared in November 2021. At December 31, 2021, associated with the study, the Company recorded an upward revision of $7.2 million to the asset retirement obligation primarily as a result of increased costs expected with the abandonment of the Etame Marin block and a change in the expected timing of the abandonment costs associated with the termination of the FPSO charter, as discussed further in Note 12. As a result of the expected timing of the abandonment of the FPSO, included in accrued liabilities in the consolidated balance sheet at December 31, 2022 and December 31, 2021 is $0.3 and $6.7 million of costs, respectively, associated with the retirement obligation associated with the FPSO.

## 12. COMMITMENTS AND CONTINGENCIES

### *Abandonment funding*

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 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 November 2021, a new abandonment study was done and the estimate used for this purpose is approximately $81.3 million ($47.8 million, net to VAALCO) on an undiscounted basis. The new abandonment estimate has been presented to the Gabonese Directorate of Hydrocarbons as required by the PSC. Through December 31, 2022, $35.0 million ($20.6 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.

On February 28, 2019, in accordance with certain foreign currency regulatory requirements, the Gabonese branch of an international commercial bank holding the abandonment funds in a USD denominated account transferred the funds to the Central Bank for CEMAC, of which Gabon is one of the six member states. The USDs were converted to local currency with a credit back to the Gabonese branch. The Etame PSC provides these payments must be denominated in USD and the CEMAC regulations provide for establishment of a USD account with the Central Bank. During the year ended December 31, 2022, the Company has recorded a $1.2 million foreign currency loss associated with the abandonment funding account. During the year ended December 31, 2021, the Company has recorded a $1.6 million foreign currency loss associated with the abandonment funding account. 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. The Company was allowed to re-establish a USD denominated account and made whole for the original USD amount of $37.3 million that was in the account prior to conversion to a local currency account in 2019. The Company is 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.

### *FPSO charter*

In connection with the charter of the FPSO, the Company, as operator of the Etame Marin block, guaranteed all of the charter payments under the charter through its contract term. At the Company's election, the charter could be extended for two one-year periods beyond September 2020. These elections have been made, and the charter has been extended through September 2022. On September 9, 2022, the Company signed an addendum to the FPSO contract which extended the use of the FPSO through October 4, 2022 and ratified certain decommissioning and demobilization items associated with exiting the contract.

Pursuant to the addendum, VAALCO Gabon agreed to pay the charterer day rate of $150,000 from August 20, 2022 through October 4, 2022, and other demobilization fees totaling $15.3 million on a gross basis, $8.9 million net to VAALCO Gabon. The Company obtained guarantees from each of the Company's joint venture owners for their respective shares of the payments. The Company's net share of the charter payment is 58.8%, or approximately $19.4 million per year. The Company recorded a liability of $0.4 million as of December 31, 2021, representing the guarantee's estimated fair value. The Company relinquished control over the FPSO in the fourth quarter of 2022. In connection with the addendum, the FPSO was decommissioned. VAALCO and the owners of the FPSO are performing a settlement of final accounting and will afterwards conclude on the restricted cash balances associated with the FPSO.

The FPSO charter payment included a $1.16 per barrel charter fee for production up to 20,000 barrels of crude oil per day and a $3.13 per barrel charter fee for those barrels produced in excess of 20,000 barrels of crude oil per day. VAALCO's net share of these payments was $22.4 million, $22.1 million and $13.1 million for the years ended December 31, 2022, 2021 and 2020, respectively.

### *Regulatory and Joint Interest Audits and Related Matters*

The Company is subject to periodic routine audits by various government agencies in Gabon, including audits of the Company's petroleum cost account, customs, taxes and other operational matters, as well as audits by other members of the contractor group under the Company's joint operating agreements.

In 2016, the government of Gabon conducted an audit of the Company's operations in Gabon, covering the years 2013 through 2014. The Company received the findings from this audit and responded to the audit findings in January 2017. Since providing the Company's response, there have been changes in the Gabonese officials responsible for the audit. The Company is working with the newly appointed representatives to resolve the audit findings. The Company does not anticipate that the ultimate outcome of this audit will have a material effect on the Company's financial condition, results of operations or liquidity.

Between 2019 and 2021, the government of Gabon conducted an audit of the operations in Gabon, covering the years 2015 and 2016. The Company received the findings from this audit and responded to the audit findings in the first quarter of 2023 and are working with the government of Gabon on the results of the findings. The Company does not anticipate that the ultimate outcome of this audit will have a material effect on the Company's financial condition, results of operations or liquidity.

In 2019, the Etame joint venture owners conducted audits for the years 2017 and 2018. In June 2020, the Company agreed to a $0.8 million payment to resolve claims made by one of the Etame Marin block joint venture owners, Addax Petroleum Gabon S.A. There are now no unresolved matters related to the joint venture owner audits for these years.

### *FSO*

On August 31, 2021, the Company and its co-venturers at Etame approved the Bareboat Contract (the "Bareboat Contract") and Operating Agreement (collectively, the "FSO Agreements") with World Carrier Offshore Services Corp. to replace the existing FPSO with a Floating Storage and Offloading unit ("FSO"). The FSO Agreements required a prepayment of $2 million gross, $1.2 million net to the Company, in 2021 and $5 million gross, $3.2 million net to the Company, in 2022 of which $6 million will be recovered against future rentals. Total field conversion expenses were $122 million gross ($77 million net to VAALCO). The FSO Agreements contain purchase provisions and termination provisions. On October 19, 2022, the vessel is on location at the Etame Marin block and the Company has issued its final acceptance certificate of the FSO.

***Dividend Policy***

On November 3, 2021, the Company announced that the Company’s board of directors adopted a cash dividend policy of an expected $0.0325 per common share commencing in the first quarter of 2022. The following table is a schedule of dividends paid during 2022:

| Dividend Payment Date | | Amount per common share | Record Date |
|---|---|---|---|
| March 18, 2022 | $ | 0.0325 | February 18, 2022 |
| June 24, 2022 | $ | 0.0325 | May 25, 2022 |
| September 23, 2022 | $ | 0.0325 | August 25, 2022 |
| December 22, 2022 | $ | 0.0325 | November 22, 2022 |
| Aggregate per share amount paid in 2022 | $ | 0.1300 | |

In the first quarter of 2023, the Company announced that the Company's board of directors increased the cash dividend to $0.0625 per common share. On February 14, 2023, our board of directors declared a quarterly cash dividend of $0.0625 per common share, which was payable on March 31, 2023 to stockholders of record at the close of business on March 24, 2023.

In connection with the RBL facility, the Company is required to provide a cash flow projection prior to any distribution, share buyback, or stock repurchase. As long as a group liquidity test is above the required ratio outlined in the RBL facility agreement, and no event of default exists, the Company may make distributions, buyback shares, or repurchase stock without further approval. In the event the liquidity test is not met, an approval or waiver would need to be obtained from Glencore in order to make distributions, buyback shares, or repurchase stock. For the year ended December 31, 2022, no specific approval or waivers were required for the Company to make distributions or repurchase stock.

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.

***Share Buyback Program***

On November 1, 2022, the Company announced that the Company’s board of directors formally ratified and approved the share buyback program that was announced on August 8, 2022 in conjunction with the Company’s business combination with TransGlobe. 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 provides for an aggregate purchase of currently outstanding common stock up to $30 million over 20 months. Payment for shares repurchased under the share buyback program will be funded using the Company's cash on hand and cash flow from operations.

The below table shows the repurchases of equity securities related to the share repurchase program during the fourth quarter of the fiscal year ended December 31, 2022:

| Period | Total Number of Shares Purchased | | Average Price Paid per Share | Total Number of Shares Purchased as Part of Publicly Announced Programs | | Maximum Amount that May Yet Be Used to Purchase Shares Under the Program |
|---|---|---|---|---|---|---|
| November 1, 2022 - November 30, 2022 | 288,758 | $ | 5.21 | 288,758 | $ | 28,500,463 |
| December 1, 2022 - December 31, 2022 | 282,163 | $ | 5.34 | 282,163 | $ | 27,000,767 |
| Total | 570,921 | | | 570,921 | | |

The following table shows the repurchases of equity securities related to the share repurchase program after December 31, 2022 through March 31, 2023:

| Period | Total Number of Shares Purchased | Average Price Paid per Share | Total Number of Shares Purchased as Part of Publicly Announced Programs | Maximum Amount that May Yet Be Used to Purchase Shares Under the Program |
|---|---|---|---|---|
| January 1, 2023 - January 31, 2023 | 350,832 | $ 4.29 | 350,832 | $ 25,502,669 |
| February 1, 2023 - February 28, 2023 | 326,992 | $ 4.61 | 326,992 | $ 24,003,172 |
| March 1, 2023 - March 31, 2023 | 303,176 | $ 4.97 | 303,176 | $ 22,503,206 |
| Total | 981,000 | | 981,000 | |

The Company continues to purchase shares under the 10b5-1 Plan for share repurchases from and including April 2023.

In connection with the RBL facility, the Company is required to provide a cash flow projection prior to any distribution, share buyback, or stock repurchase. As long as a group liquidity test is above the required ratio outlined in the RBL facility agreement, and no event of default exists, we may make distributions, buyback shares, or repurchase stock without further approval. In the event the liquidity test is not met, an approval or waiver would need to be obtained from Glencore in order to make distributions, buyback shares, or repurchase stock. For the year ended December 31, 2022, no specific approval or waivers were required for the Company to make distributions or repurchase stock.

The actual timing number and value of shares repurchased under the share buyback program will depend on a number of factors, including constraints specified in the Plan, the Company's stock price, general business and market conditions, and alternative investment opportunities. Under the Plan, the Company's third-party broker, subject to SEC regulations regarding certain price, market, volume and timing constraints, would have authority to purchase the Company's common stock in accordance with the terms of the Plan.

***Merged Concession Agreement***

On January 20, 2022, prior to the consummation of the Arrangement, TransGlobe announced a fully executed concession agreement "Merged Concession Agreement" with the Egyptian General Petroleum Corporation ("EGPC") that merged the three existing Eastern Desert concessions with a 15-year primary term and improved economics. In advance of the Minister of Petroleum and Mineral Resources of the Arab Republic of Egypt (the "Minister") executing the Merged Concession Agreement, TransGlobe paid the first modernization payment of $15.0 million and signature bonus of $1.0 million as part of the conditions precedent to the official signing ceremony on January 19, 2022. On February 1, 2022, TransGlobe paid the second modernization payment of $10.0 million. In accordance with the Merged Concession. The Company will make three further annual equalization payments of $10.0 million each beginning February 1, 2024 until February 1, 2026. VAALCO recorded modernization payment liabilities of $35.5 million at December 31, 2022. On the consolidated balance sheet, $9.9 million of the modernization payment liability was recorded in the line item "Accrued liabilities and other" and $25.6 million was recorded in "Other long-term liabilities". VAALCO agreed to substitute the 2023 payment and issue a $10.0 million credit against receivables owed from EGPC for the amount due on February 1, 2023.

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 (the "Merged Concession Effective Date") for a total of $150 million commencing on the Merged Concession Effective Date"). Through December 31, 2022, all investments have exceeded the five-year minimum $50 million threshold and any excess carries forward to offset against subsequent five-year commitments.

As the Merged Concession Agreement is effective as of February 1, 2020, there will be effective date adjustment 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. In accordance with GAAP, the Company has recognized a receivable in connection with the effective date adjustment of $67.5 million as of October 13, 2022, based on historical realized prices. However, the cumulative value to be received as a result of the effective date adjustment is currently being finalized with the EGPC and could result in a range of outcomes based on the final price per barrel negotiated. As of December 31, 2022, $17.2 of the effective date adjustment has been offset by amounts otherwise due to EGPC and the remaining $50.3 million is recorded on the consolidated balance sheet in Receivables-Other, net.

***Other contractual commitments***

In August 2020, the Company entered into an agreement to acquire approximately 1,000 square kilometers of 3-D seismic data in the Company's Etame Marin block. The acquisition was completed in the fourth quarter of 2020 and the processing of the seismic data began in January 2021. The cost, net to VAALCO, is approximately $2.2 million or $3.4 million gross.

In June 2021, the Company entered into a short-term agreement with an affiliate of Borr Drilling Limited to drill a minimum of three wells with options to drill additional wells. The 2021/2022 drilling program commenced in December 2021 and was completed in November 2022.

**13. DEBT**

As of December 31, 2022 and 2021, the Company had no outstanding debt.

***RBL Facility***

On May 16, 2022, the Borrower entered into the Facility Agreement by and among the Company, VAALCO Gabon, Glencore, the Law Debenture Trust Corporation P.L.C., as security agent, and the Lenders, providing for a senior secured reserve-based revolving credit facility in an aggregate maximum principal amount of up to $50.0 million (the "Initial Total Commitment"). In addition, subject to certain conditions, the Borrower may agree with any Lender or other bank or financial institution to increase the total commitments available under the Facility by an aggregate amount not to exceed $50.0 million (any such increase, an "Additional Commitment"). Beginning October 1, 2023 and thereafter on April 1 and October 1 of each year during the term of the Facility, the Initial Total Commitment, as increased by any Additional Commitment, will be reduced by $6.25 million.

The Facility provides for determination of the borrowing base asset based on the Company's proved producing reserves in Gabon and a portion of the Company's proved undeveloped reserves in Gabon. The borrowing base is determined and re-determined by the Lenders on March 31 and September 30 of each year. Based on the redetermination performed during the year, there was no change in the borrowing base.

Each loan under the Facility will bear interest at a rate equal to LIBOR plus a margin (the "Applicable Margin") of (i) 6.00% until the third anniversary of the Facility Agreement or (ii) 6.25% from the third anniversary of the Facility Agreement until the Final Maturity Date (defined below).

Pursuant to the Facility Agreement, the Company shall pay to Glencore for the account of each Lender a quarterly commitment fee equal to (i) 35% per annum of the Applicable Margin on the daily amount by which the lower of the total commitments and the borrowing base amount exceeds the amount of all outstanding utilizations under the Facility, plus (ii) 20% per annum of the Applicable Margin on the daily amount by which the total commitments exceed the borrowing base amount. The Borrower is also required to pay customary arrangement and security agent fees.

The Facility Agreement contains certain debt covenants, including that, as of the last day of each calendar quarter, (i) the ratio of Consolidated Total Net Debt to EBITDAX (as each term is defined in the Facility Agreement) for the trailing 12 months shall not exceed 3.0x and (ii) consolidated cash and cash equivalents shall not be lower than $10.0 million. As of December 31, 2022, the Company's borrowing base was $50.0 million. The amount the Company is able to borrow with respect to the borrowing base is subject to compliance with the financial covenants and other provisions of the Facility Agreement. At December 31, 2022, the Company was in compliance with all debt covenants and had no outstanding borrowings under the facility. With regard to the requirement that the Company deliver its fiscal year 2022 annual financial statements to Glencore within 90 days of the end of each fiscal year, the Company has requested and received an extension until April 17, 2023.

The Facility will mature on the earlier of (i) the fifth anniversary of the date on which all conditions precedent to the first utilization of the Facility have been satisfied and (ii) the Reserve Tail Date (as defined in the Facility Agreement) (the "Final Maturity Date").

Deferred financing costs incurred in connection with securing the Facility were $1.9 million, $2.1 million net of amortization of $0.2 million, which is carried in the accompanying consolidated balance sheets in the line item "Other long-term assets" and is amortized on a straight-line basis, which approximates the effective interest method, over the term of the Facility and included in interest expense in the accompanying consolidated statements of operations and comprehensive income (loss).

***ATB Facility***

In connection with the Arrangement with TransGlobe in October 2022, and prior to the effective time of the Arrangement, TransGlobe repaid in full all outstanding obligations and liabilities owed under TransGlobe's credit facility with ATB Financial (the "ATB Facility"), representing approximately Canadian $4.1 million. On December 19, 2022, TransGlobe, as an indirect wholly-owned subsidiary of the Company, voluntarily delivered a notice of termination to ATB Financial relating to the ATB Facility. As of December 31, 2022, no amounts were drawn on the revolving loan facility. On January 5, 2023, the ATB Facility was formally closed. Termination of the ATB Facility will not affect the Company's $50.0 million senior secured reserve-based revolving credit facility with Glencore.

## 14. 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.

***Practical Expedients***

The Company elected to use all the practical expedients, effectively carrying over its previous identification and classification of leases that existed as of January 1, 2019. Additionally, a lessee may elect not to recognize ROU assets and liabilities arising from short-term leases provided there is no purchase option the entity is likely to exercise. The Company has elected this short-term lease exemption.

***Operating leases***

The Company is currently a party to several lease agreements for the corporate office, a drilling rig, rental of marine vessels and helicopters, warehouse and storage facilities, equipment and the FPSO. The duration for these agreements ranges from 6 to 27 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 the FPSO, the marine vessels, helicopter, certain equipment and warehouse and storage facilities used in the joint operations includes the gross amount of the lease components.

During the third quarter of 2019, the Company notified the lessor of the FPSO of its intent to extend the lease term by the first option that extends the FPSO lease to September 2021. Similarly, during the third quarter of 2020, the Company gave notification to extend the FPSO lease to September 2022.

On September 9, 2022, the Company entered into an addendum to the FPSO contract which extends the contract from September 2022 through October 4, 2022 and sets forth both the Company’s and lessor's rights and obligations with respect to demobilization and decommissioning. Under ASC 842, the Company was required to reassess the lease for lease classification at the time the Company entered into the amendment. Accordingly, the Company assessed the lease as a short-term lease.

The marine vessels and certain equipment leases include provisions for variable lease payments, under which the Company is required to make additional payments based on the level of production or the number of days or hours the asset is deployed, or the number of persons onboard the vessel. 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 used in the operations of the Etame Marin block and for equipment, offices and vehicles used in the operations of Canada and Egypt. The duration for these agreements ranges from 10 to 117 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.

On February 15, 2022, the Company signed a contract for a finance lease of generators and related parts. The related ROU asset and lease liability was recorded on the lease commencement date of February 15, 2022.

In August 2021, the Company signed the FSO agreements to lease a FSO to replace the current FPSO whose term ended in October 2022. Under the terms of the FSO agreements, a third party is expected to modify the leased vessel in order to meet the Company's crude-oil production requirements. The vessel arrived on location in the Etame Marin block in August 2022. On October 19, 2022, the Company signed the final acceptance certificate at which time control of the FSO vessel transferred to the Company.

***All leases***

For all leases that contain an option to extend the initial lease term, the Company has evaluated whether it will extend the lease beyond the initial lease term. When the Company believes it will utilize these leased assets beyond the initial lease term, those payments have been included in the calculation for 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, 2022 and 2021, the components of the lease costs and supplemental information was as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2022** | **2021** | **2020** |
| Lease cost: | | *(in thousands)* | |
| Finance lease cost [1] | **$ 3,682** | $ — | $ — |
| Operating lease cost | **11,040** | 17,692 | 17,528 |
| Short-term lease cost [2] | **5,213** | 2,258 | 1,408 |
| Variable lease cost [3] | **4,513** | 6,188 | 7,572 |
| Total lease expense | **24,448** | 26,138 | 26,508 |
| Lease costs capitalized | **4,127** | 232 | 3,456 |
| Total lease costs | **$ 28,575** | $ 26,370 | $ 29,964 |

(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:

| | 2022 | 2021 | 2020 |
|---|---|---|---|
| Other information: | | | |
| Cash paid for amounts included in the measurement of lease liabilities: | | | |
| Financing cash flows attributable to finance leases | **$ 3,039** | $ — | $ — |
| Weighted-average remaining lease term (in years) | **9.65** | — | — |
| Weighted-average discount rate | **4.59%** | — | — |
| Operating cash flows attributable to operating leases | **$ 19,300** | $ 23,925 | $ 26,178 |
| Weighted-average remaining lease term (in years) | **1.35** | 0.91 | 1.80 |
| Weighted-average discount rate | **9.91%** | 5.91% | 6.09% |

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, | | |
|---|---|---|---|
| | 2022 | 2021 | 2020 |
| | | *(in thousands)* | |
| Finance lease cost | **$ 2,188** | $ — | $ — |
| Production expense | **12,222** | 13,457 | 7,904 |
| General and administrative expense | **160** | 193 | 197 |
| Lease costs billed to the joint venture owners | **11,390** | 12,573 | 20,692 |
| Total lease expense | **25,960** | 26,223 | 28,793 |
| Lease costs capitalized | **2,615** | 147 | 1,171 |
| Total lease costs | **$ 28,575** | $ 26,370 | $ 29,964 |

The following table describes the future maturities of the Company's operating lease liabilities at December 31, 2022:

| Year | Operating Leases | Finance Leases |
|---|---|---|
| | *(in thousands)* | |
| 2023 | $ 2,478 | $ 11,619 |
| 2024 | 671 | 11,495 |
| 2025 | 33 | 13,495 |
| 2026 | — | 13,893 |
| 2027 | — | 12,350 |
| Thereafter | — | 42,097 |
| | 3,182 | 104,949 |
| Less: imputed interest | 182 | 18,890 |
| Total lease liabilities | $ 3,000 | $ 86,059 |

Under the joint operating agreements, other joint venture owners are obligated to fund $44.6 million of the $108.1 million in future lease liabilities as of December 31, 2022.

## 15. CURRENT ACCRUED LIABILITIES AND OTHER

Accrued liabilities and other balances were comprised of the following:

| | As of December 31, 2022 | As of December 31, 2021 |
|---|---|---|
| | (in thousands) | |
| Accrued accounts payable invoices | **$ 28,360** | $ 11,967 |
| Gabon DMO, PID and PIH obligations | **10,509** | 9,465 |
| Derivative liability - crude oil swaps | **—** | 4,806 |
| Capital expenditures | **26,618** | 11,327 |
| Stock appreciation rights – current portion | **570** | 609 |
| Accrued wages and other compensation | **8,161** | 2,124 |
| ARO Obligation | **306** | 6,745 |
| Egypt Modernization Payments | **9,933** | — |
| Other | **6,935** | 2,401 |
| Total accrued liabilities and other | **$ 91,392** | $ 49,444 |

## 16. SHAREHOLDERS' EQUITY

On October 13, 2022, in connection with the closing of the Arrangement, the total number of authorized shares of common stock of the Company was increased from 100 million to 160 million and VAALCO issued approximately 49.3 million shares to TransGlobe's shareholders.

***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, 2022 or 2021.

***Treasury stock***

On November 1, 2022, the Company announced that the board of directors formally ratified and approved the share buyback program that was announced on August 8, 2022. The Plan provides for an aggregate purchase of currently outstanding common stock up to $30 million over 20 months. Payment for shares repurchased under the share buyback program will be funded using the Company's cash on hand and cash flow from operations.

The below table shows the repurchases of the Company's equity securities during the fourth quarter of the fiscal year ended December 31, 2022:

| Period | Total Number of Shares Purchased | Average Price Paid per Share | Total Number of Shares Purchased as Part of Publicly Announced Programs | Maximum Amount that May Yet Be Used to Purchase Shares Under the Program |
|---|---|---|---|---|
| November 1, 2022 - November 30, 2022 | 288,758 | $ 5.21 | 288,758 | $ 28,500,463 |
| December 1, 2022 - December 31, 2022 | 282,163 | $ 5.34 | 282,163 | $ 27,000,767 |
| Total | 570,921 | | 570,921 | |

For the majority of restricted stock awards granted by the Company, the number of shares issued to the participant on the vesting date are net of shares withheld to meet applicable tax withholding requirements. In addition, when options are exercised, the participant may elect to remit shares to the Company to cover the tax liability and the cost of the exercised options. When this happens, the Company adds these shares to treasury stock and pays the taxes on the participant's behalf.

Although these withheld shares are not issued or considered common stock repurchases under the Company's stock repurchase program, they are treated as common stock repurchases in the financial statements as they reduce the number of shares that would have been issued upon vesting.

## 17. 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 ("2014 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, 2022, 3,870,496 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 and production expense associated with the issuance of stock options, restricted stock and stock appreciation rights. During the years ended December 31, 2022, 2021 and 2020, the Company settled in cash \$0.8 million, \$3.3 million and \$0.3 million, respectively, for SARs. During the years ended December 31, 2022, 2021 and 2020, the Company received in cash \$0.3 million, \$1.4 million and \$0.1 million, respectively from stock option exercises. Because the Company does not pay significant U.S. federal income taxes, no amounts were recorded for future tax benefits.

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2022** | **2021** | **2020** |
| | | *(in thousands)* | |
| Stock-based compensation - equity awards | **$ 2,045** | $ 1,060 | $ 848 |
| Stock-based compensation - liability awards | **155** | 1,399 | (734) |
| Total stock-based compensation | **$ 2,200** | $ 2,459 | $ 114 |

### *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 March 2022, the Company granted options to certain employees of the Company that are considered performance stock options to purchase an aggregate of 241,358 shares at an exercise price of \$6.41 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 \$7.37 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 \$8.48 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 \$9.75 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.

The Company used the Monte Carlo simulation to calculate the grant date fair value of performance stock option awards. The fair value of these awards will be amortized to expense over the derived service period of the option.

For options that do not contain a market or performance condition, the Company uses the Black-Scholes model to calculate the grant date fair value of stock option awards. This fair value is then amortized to expense over the service period of the option.

During the year ended December 31, 2022, 2021 and 2020 the weighted average assumptions shown below were used to calculate the weighted average grant date fair value of option grants under the Monte Carlo model in 2022 and 2021 and Black-Scholes models.

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2022** | **2021** | **2020** |
| Weighted average exercise price - ($/share) | **$ 6.41** | $ 3.14 | $ 1.23 |
| Expected life in years | **6.0** | 6.0 | 6.0 |
| Average expected volatility | **72%** | 75% | 74 |
| Risk-free interest rate | **1.98%** | 0.95% | 0.42 |
| Expected dividend yield | **2.30%** | — | — |
| Weighted average grant date fair value - ($/share) | **$ 2.84** | $ 2.07 | $ 0.79 |

Stock option activity associated with the Monte Carlo model for the year ended December 31, 2022 is provided below:

| | **Number of Shares Underlying Options** *(in thousands)* | **Weighted Average Exercise Price Per Share** | **Weighted Average Remaining Contractual Term** *(in years)* | **Aggregate Intrinsic Value** *(in thousands)* |
|---|---|---|---|---|
| Outstanding at January 1, 2022 | 359 | $ 1.96 | | |
| Granted | 241 | 6.41 | | |
| Exercised | (47) | (1.23) | | |
| Unvested shares forfeited | (109) | (4.03) | | |
| Vested shares expired | — | — | | |
| Outstanding at December 31, 2022 | 444 | $ 3.95 | 7.15 | $ 632 |
| Exercisable at December 31, 2022 | 147 | $ 1.83 | 3.92 | $ 400 |

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. The intrinsic performance stock option awards exercised in 2022 was $0.2 million.

As of December 31, 2022, unrecognized compensation cost related to outstanding performance stock option awards was $0.4 million, which is expected to be recognized over a weighted average period of 2.0 years.

During the year ended December 31, 2022, no shares were added to treasury as a result of tax withholding on performance stock option awards exercised.

Stock option activity associated with the Black-Scholes model for the year ended December 31, 2022 is provided below:

| | Number of Shares Underlying Options (in thousands) | Weighted Average Exercise Price Per Share | Weighted Average Remaining Contractual Term (in years) | Aggregate Intrinsic Value (in thousands) |
|---|---|---|---|---|
| Outstanding at January 1, 2022 | 615 | $ 1.58 | | |
| Granted | — | — | | |
| Exercised | (228) | (1.12) | | |
| Unvested shares forfeited | — | — | | |
| Vested shares expired | — | — | | |
| Outstanding at December 31, 2022 | 387 | $ 1.86 | 0.83 | $ 1,045 |
| Exercisable at December 31, 2022 | 387 | $ 1.86 | 0.83 | $ 1,045 |

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 2022, 2021 and 2020 was $1.2 million, $1.6 million, and $43 thousand, respectively.

As of December 31, 2022, unrecognized compensation cost related to outstanding stock options was none.

During the year ended December 31, 2022, 49,063 shares were added to treasury as a result of tax withholding on options exercised. During the year ended December 31, 2021, 464,671 shares were added to treasury as a result of tax withholding on options exercised.

***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). In March 2022, the Company issued 353,424 shares of service-based restricted stock to employees, with a grant date fair value of $6.41 per share. In addition, in June 2022, the Company issued 30,687 shares of service-based restricted stock to directors, with a grant date fair value of $8.31 per share. The vesting of the foregoing shares is dependent upon, among other things, the employees' and directors' continued service with the Company.

The following is the activity for the Company's restricted stock for the year ended December 31, 2022:

| | Restricted Stock (in thousands) | Weighted Average Grant Date Fair Value |
|---|---|---|
| Non-vested shares outstanding at January 1, 2022 | 741 | $ 2.36 |
| Awards granted | 384 | 6.56 |
| Awards vested | (334) | 2.25 |
| Awards forfeited | (126) | 3.68 |
| Non-vested shares outstanding at December 31, 2022 | 665 | $ 4.59 |

The total fair value of vested restricted stock awards during 2022, 2021 and 2020 was $2.4 million, $1.8 million, and $0.2 million, respectively. The weighted average grant date fair value per share of restricted stock awards, which vested during 2022, 2021 and 2020, was $2.25, $1.28 and $1.35, respectively.

As of December 31, 2022, unrecognized compensation cost related to restricted stock totaled $1.3 million and is expected to be recognized over a weighted average period of 1.4 year.

During the year ended December 31, 2022, 69,135 shares were added to treasury as a result of tax withholding on the vesting of restricted shares. During the year ended December 31, 2021, 68,134 shares were added to treasury as a result of tax withholding on the vesting of restricted shares.

In connection with the Arrangement with TransGlobe and pursuant to the Arrangement Agreement, at the effective time of the Arrangement, certain awards previously issued to TransGlobe's key employees and board members who continued their relationship as employees or board members of VAALCO following the Arrangement, will continue to be governed by the applicable TransGlobe plan, provided that each such applicable plan has been amended to provide that VAALCO common stock shall be issuable in lieu of cash or TransGlobe common stock with respect to TransGlobe's deferred share units ("DSU"s), performance share units ("PSU"s) and restricted stock units ("RSU"s), in each case, based on the exchange ratio in the Arrangement. For the PSUs that will remain outstanding following the effective time of the Arrangement as described in the immediately preceding sentence, the applicable vesting percentage was determined by the TransGlobe board of directors to be 200% for PSUs granted in 2020 and 2021; and 64.4% for PSUs granted in 2022.

On the effective date of the Arrangement, October 13, 2022, the combined fair value of the DSUs, PSU's and RSU's liability from TransGlobe was $6.0 million. On December 16, 2022, the Compensation Committee determined that the awards would be settled in shares from the 2020 Plan, thereby converting all the awards from cash-settled liability awards to equity awards. On the date of this conversion, the awards were revalued based on VAALCO's share price, and the Company recognized a gain of $0.6 million in its consolidated statements of operations and comprehensive income (loss).

RSUs were issued to directors, officers and employees of TransGlobe in the ordinary course of business prior to the Arrangement. Each RSU vests annually over a three-year period. On December 16, 2022, Compensation Committee determined that the awards would be settled in shares from the 2020 Plan, thereby converting all the awards to equity awards instead of cash-settled liability awards. RSU activity for the period December 16, 2022 through December 31, 2022 is presented in the table below:

| | **Restricted Stock** | **Weighted Average Conversion Date Fair Value** |
|---|---|---|
| | ***(in thousands)*** | |
| Non-vested shares outstanding at December 16, 2022 | — | $ — |
| Awards converted | 386 | 4.27 |
| Awards vested | (3) | 4.27 |
| Awards forfeited | — | — |
| Non-vested shares outstanding at December 31, 2022 | 383 | $ 4.27 |

The total fair value of vested RSU awards during 2022 was $14 thousand. The weighted average grant date fair value per share of RSU, which vested during 2022, was $4.27.

As of December 31, 2022, unrecognized compensation cost related to RSU's totaled $0.5 million and is expected to be recognized over a weighted average period of 1.7 years.

During the year ended December 31, 2022, 1,381 shares were added to treasury as a result of tax withholding on the vesting of 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 Arrangement, the applicable vesting percentage was determined by the TransGlobe board of directors to be 200% for PSUs granted in 2020 and 2021; and 64.4% for PSUs granted in 2022. All PSUs granted vest on the third anniversary of their grant date. On December 16, 2022, the Compensation Committee determined that the awards would be settled in shares from the 2020 Plan, thereby converting all the awards to equity awards instead of cash-settled liability awards. PSU activity for the period December 16, 2022 through December 31, 2022 is presented in the table below:

| | **Restricted Stock** | **Weighted Average Conversion Date Fair Value** |
|---|---|---|
| | *(in thousands)* | |
| Non-vested shares outstanding at December 16, 2022 | — | $ — |
| Awards converted | 690 | 4.27 |
| Awards vested | — | — |
| Awards forfeited | — | — |
| Non-vested shares outstanding at December 31, 2022 | 690 | $ 4.27 |

No PSU awards vested from October 14, 2022 through December 31, 2022.

As of December 31, 2022, unrecognized compensation cost related to PSU's totaled $0.7 million and is expected to be recognized over a weighted average period of 1.1 years.

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. On December 16, 2022, the Compensation Committee determined that the awards would be settled in shares from the 2020 Plan, thereby converting all the awards to equity awards instead of cash-settled liability awards. DSU activity for the period December 16, 2022 through December 31, 2022 is presented in the table below:

| | **Restricted Stock** | **Weighted Average Conversion Date Fair Value** |
|---|---|---|
| | *(in thousands)* | |
| Non-vested shares outstanding at December 16, 2022 | — | $ — |
| Awards converted | 460 | 4.27 |
| Awards vested | (460) | 4.27 |
| Awards forfeited | — | — |
| Non-vested shares outstanding at December 31, 2022 | — | $ — |

***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.

During the years ended December 31, 2022 and 2021, the Company did not grant SARs to employees or directors. SAR activity for the year ended December 31, 2022 is provided below:

| | Number of Shares Underlying SARs | Weighted Average Exercise Price Per Share | Term | Aggregate Intrinsic Value |
|---|---|---|---|---|
| | *(in thousands)* | | *(in years)* | *(in thousands)* |
| Outstanding at January 1, 2022 | 362 | $ 1.81 | | |
| Granted | — | — | | |
| Exercised | (160) | 1.74 | | |
| Unvested SARs forfeited | — | — | | |
| Vested SARs expired | — | — | | |
| Outstanding at December 31, 2022 | 202 | $ 1.87 | 0.85 | $ 542 |
| Exercisable at December 31, 2022 | 202 | $ 1.87 | 0.85 | $ 542 |

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 2022, 2021 and 2020 was $0.8 million.

SARs 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.

***Other Benefit Plans***

The Company has adopted forms of change in control agreements for its named executive officers and certain other officers of the Company as well as a severance plan for its Houston-based non-executive employees in order to provide severance benefits in connection with a change in control. 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 and participants in the severance plan 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.

The Company sponsors a 401(k) plan, with a company match feature, for the employees. Costs of $0.4 million for the year ended December 31, 2022, $0.3 million for the year ended December 31, 2021, and $0.4 million for the year ended December 31, 2020, respectively, were incurred for the Company's matching contribution and for administering the plan.

**18. RELATED PARTY TRANSACTIONS**

On November 7, 2022, the Company promoted Thor Pruckl ("Mr. Pruckl"*)* to the position of Chief Operating Officer of the Company, effective November 7, 2022.

On March 14, 2022, in the ordinary course of business, the Company entered into a professional services agreement (the "Services Agreement") with J. Pruckl Holdings Ltd. ("Pruckl Holdings"), an entity owned and controlled by James Pruckl, Mr. Pruckl's son. Under the Services Agreement, Pruckl Holdings designates James Pruckl to render project contract engineering services for the Company that include pipeline in-line data analysis, jacket structures and subsea pipeline inspections and other related services in connection with the Etame Marin block located at offshore Gabon in West Africa. As of December 31, 2022, the Company has been invoiced approximately $177 thousand in the aggregate and approximately $33 thousand was still outstanding at December 31, 2022, pursuant to the Services Agreement.

**19. OTHER COMPREHENSIVE INCOME**

The Company's other comprehensive income of $1.2 million is for the period of October 14 – December 31, 2022, the period after the acquisition of TransGlobe. The functional currency of TransGlobe Energy Corporation is the Canadian Dollar. All of the Company's other comprehensive income arises from the currency translation of TransGlobe Energy Corporation to USD.

The components of accumulated other comprehensive income are as follows:

| | **Currency Translation Adjustments** |
|---|---|
| | ***(in thousands)*** |
| Balance at December 31, 2021 | $ — |
| Accumulated other comprehensive income (loss) before reclassifications | 1,179 |
| Amounts reclassified from accumulated other comprehensive income (loss) | — |
| Balance at December 31, 2022 | $ 1,179 |

**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 (Africa), and onshore in Egypt and Canada.

***Costs Incurred for Acquisition, Exploration and Development Activities***

| **Costs incurred during the year:** | **Gabon** | **Egypt** | **Canada** | **Total** |
|---|---|---|---|---|
| Year Ended December 31, 2022 | | *(in thousands)* | | |
| Exploration costs - capitalized | **$ 47** | $ — | $ — | **$ 47** |
| Exploration costs - expensed | **258** | — | — | **258** |
| Acquisition of properties | — | **170,982** | **104,390** | **275,372** |
| Development costs | **162,328** | **7,515** | **2,187** | **172,030** |
| Total | **$ 162,633** | **$ 178,497** | **$ 106,577** | **$ 447,707** |

| | **Gabon** | **Total** |
|---|---|---|
| Year Ended December 31, 2021 | *(in thousands)* | |
| Exploration costs - capitalized | $ 254 | $ 254 |
| Exploration costs - expensed | 1,579 | 1,579 |
| Acquisition of properties | 42,744 | 42,744 |
| Development costs | 36,223 | 36,223 |
| Total | $ 80,800 | $ 80,800 |

| | **Gabon** | **Total** |
|---|---|---|
| Year Ended December 31, 2020 | *(in thousands)* | |
| Exploration costs - capitalized | $ 8,484 (1) | $ 8,484 |
| Exploration costs - expensed | 3,588 | 3,588 |
| Acquisition of properties | — | — |
| Development costs | 731 | 731 |
| Total | $ 12,803 | $ 12,803 |

**(1) -** Primarily associated with the Southeast Etame 4P appraisal wellbore.

***Capitalized Costs Relating to crude oil, natural gas and NGLs Producing Activities***

Capitalized costs pertain to the producing activities in Gabon, Egypt and Canada and to undeveloped leasehold in Gabon, Egypt, Canada and Equatorial Guinea.

| | **As of December 31,** | |
|---|---|---|
| | **2022** | **2021** |
| Capitalized costs: | *(in thousands)* | |
| Properties not being amortized | **$ 71,670** | $ 55,488 |
| Properties being amortized | **1,406,888** | 488,756 |
| Total capitalized costs | **$ 1,478,558** | $ 544,244 |
| Less accumulated depletion, amortization and impairment | **(986,952)** | (451,498) |
| Net capitalized costs | **$ 491,606** | $ 92,746 |

***Results of Operations for crude oil, natural gas and NGLs Producing Activities***

For Egypt and Canada, all activity pertains to the period of October 14, 2022 - December 31, 2022, after the acquisition of TransGlobe.

| | International | | | | |
|---|---|---|---|---|---|
| | **Gabon** | **Egypt** | **Canada** | **U.S.** | **Total** |
| Year Ended December 31, 2022 | | | *(In thousands)* | | |
| Revenues | **$ 306,775** | **$ 37,710** | **$ 9,841** | $ — | **$ 354,326** |
| Production costs and other expense (1) | **(108,701)** | **(11,936)** | **(1,972)** | — | **(122,609)** |
| Depreciation, depletion, amortization | **(34,651)** | **(10,444)** | **(2,921)** | — | **(48,016)** |
| Exploration expenses | **(258)** | — | — | — | **(258)** |
| Other operating expense | **38** | — | — | — | **38** |
| Bad debt recovery (expense) | **(2,743)** | — | — | — | **(2,743)** |
| Income tax benefit (expense) | **(16,641)** | **(6,254)** | — | — | **(22,895)** |
| Results from crude oil and natural gas producing activities | **$ 143,819** | **$ 9,076** | **$ 4,948** | $ — | **$ 157,843** |

| | **Gabon** | **U.S.** | **Total** |
|---|---|---|---|
| Year Ended December 31, 2021 | | *(In thousands)* | |
| Crude oil and natural gas sales | $ 199,075 | $ — | $ 199,075 |
| Production costs and other expense (1) | (81,984) | — | (81,984) |
| Depreciation, depletion, amortization | (20,972) | — | (20,972) |
| Exploration expenses | (1,579) | — | (1,579) |
| Other operating expense | (440) | — | (440) |
| Bad debt recovery (expense) | (875) | — | (875) |
| Income tax benefit (expense) | (9,626) | — | (9,626) |
| Results from crude oil and natural gas producing activities | $ 83,599 | $ — | $ 83,599 |

| | **Gabon** | **U.S.** | **Total** |
|---|---|---|---|
| Year Ended December 31, 2020 | | *(In thousands)* | |
| Crude oil and natural gas sales | $ 67,176 | $ — | $ 67,176 |
| Production costs and other expense (1) | (38,176) | (5) | (38,181) |
| Depreciation, depletion, amortization | (9,028) | — | (9,028) |
| Exploration expenses | (3,588) | — | (3,588) |
| Impairment of proved properties | (30,625) | — | (30,625) |
| Other operating expense | (1,669) | — | (1,669) |
| Bad debt recovery (expense) | (1,165) | — | (1,165) |
| Income tax benefit (expense) | 10,785 | — | 10,785 |
| Results from crude oil and natural gas producing activities | $ (6,290) | $ (5) | $ (6,295) |

(1) Includes local general and administrative expenses but excludes corporate general and administrative expenses and allocated corporate overhead.

***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*."

For Egypt and Canada, all activity pertains to the period of October 14, 2022 - December 31, 2022, after the acquisition of TransGlobe.

| | **Oil** | | | |
|---|---|---|---|---|
| Proved reserves: | **Gabon (MBbls)** | **Egypt (MBbls)** | **Canada (MBbls)** | **Total (MBbls)** |
| Balance at January 1, 2020 | 4,966 | — | — | 4,966 |
| Production | (1,776) | — | — | (1,776) |
| Extensions and discoveries | 497 | — | — | 497 |
| Revisions of previous estimates | (471) | — | — | (471) |
| Balance at December 31, 2020 | 3,216 | — | — | 3,216 |
| Production | (2,599) | — | — | (2,599) |
| Purchase of reserves | 2,633 | — | — | 2,633 |
| Revisions of previous estimates | 7,968 | — | — | 7,968 |
| Balance at December 31, 2021 | 11,218 | — | — | 11,218 |
| Production | **(2,971)** | **(639)** | **(108)** | **(3,718)** |
| Purchase of reserves | — | **9,216** | **3,715** | **12,931** |
| Extensions and discoveries | — | — | — | — |
| Revisions of previous estimates | **1,972** | — | — | **1,972** |
| Balance at December 31, 2022 | **10,219** | **8,577** | **3,607** | **22,403** |

| | **Oil** | | | |
|---|---|---|---|---|
| | **Gabon (MBbls)** | **Egypt (MBbls)** | **Canada (MBbls)** | **Total (MBbls)** |
| Year-end proved developed reserves: | | | | |
| 2022 | **10,219** | **8,001** | **1,722** | **19,942** |
| 2021 | 7,227 | — | — | 7,227 |
| 2020 | 3,216 | — | — | 3,216 |
| Year-end proved undeveloped reserves: | | | | |
| 2022 | — | **576** | **1,885** | **2,461** |
| 2021 | 3,991 | — | — | 3,991 |
| 2020 | — | — | — | — |

| | **Natural Gas** | | | |
|---|---|---|---|---|
| Proved reserves: | **Gabon (MMcf)** | **Egypt (MMcf)** | **Canada (MMcf)** | **Total (MMcf)** |
| Balance at December 31, 2021 | — | — | — | — |
| Production | — | — | **(396)** | **(396)** |
| Purchase of reserves | — | — | **16,935** | **16,935** |
| Extensions and discoveries | — | — | — | — |
| Revisions of previous estimates | — | — | — | — |
| Balance at December 31, 2022 | — | — | **16,539** | **16,539** |

| | Natural Gas | | | |
|---|---|---|---|---|
| | Gabon (MMcf) | Egypt (MMcf) | Canada (MMcf) | Total (MMcf) |
| Year-end proved developed reserves: | | | | |
| 2022 | — | — | **11,023** | **11,023** |
| Year-end proved undeveloped reserves: | | | | |
| 2022 | — | — | **5,516** | **5,516** |

| | NGLs | | | |
|---|---|---|---|---|
| Proved reserves: | Gabon (MBbls) | Egypt (MBbls) | Canada (MBbls) | Total (MBbls) |
| Balance at December 31, 2021 | — | — | — | — |
| Production | — | — | **(73)** | **(73)** |
| Purchase of reserves | — | — | **2,870** | **2,870** |
| Extensions and discoveries | — | — | — | — |
| Revisions of previous estimates | — | — | — | — |
| Balance at December 31, 2022 | — | — | **2,797** | **2,797** |

| | NGLs | | | |
|---|---|---|---|---|
| | Gabon (MBbls) | Egypt (MBbls) | Canada (MBbls) | Total (MBbls) |
| Year-end proved developed reserves: | | | | |
| 2022 | — | — | **1,855** | **1,855** |
| Year-end proved undeveloped reserves: | | | | |
| 2022 | — | — | **942** | **942** |

| | Total Reserves (1) | | | |
|---|---|---|---|---|
| Proved reserves: | Gabon (MBoe) | Egypt (MBoe) | Canada (MBoe) | Total (MBoe) |
| Balance at January 1, 2020 | 4,966 | — | — | 4,966 |
| Production | (1,776) | — | — | (1,776) |
| Extensions and discoveries | 497 | — | — | 497 |
| Revisions of previous estimates | (471) | — | — | (471) |
| Balance at December 31, 2020 | 3,216 | — | — | 3,216 |
| Production | (2,599) | — | — | (2,599) |
| Purchase of reserves | 2,633 | — | — | 2,633 |
| Revisions of previous estimates | 7,968 | — | — | 7,968 |
| Balance at December 31, 2021 | 11,218 | — | — | 11,218 |
| Production | **(2,971)** | **(639)** | **(247)** | **(3,857)** |
| Purchase of reserves | — | **9,216** | **9,408** | **18,624** |
| Extensions and discoveries | — | — | — | — |
| Revisions of previous estimates | **1,972** | — | — | **1,972** |
| Balance at December 31, 2022 | **10,219** | **8,577** | **9,161** | **27,957** |

(1) - To convert Natural Gas to MBoe, MMcf is divided by 6.

The proved developed reserves are located offshore Gabon, in Egypt and in Canada. In 2022, operations in Gabon had 2.0 MMBbls of positive revision of reserves due to the 2021/2022 drilling campaign. 0.7 MMBbls of the positive revision was due to performance and the remaining 1.3 MMBbls of positive revisions was due to price. The company also acquired 9.2 MMBbls in oil reserves in Egypt and 9.4 MMBoe of reserves in Canada as a result of the TransGlobe acquisition. In 2021, the Company added 2.6 MMBbls of reserves due the acquisition of Sasol's interest in the Etame Marin block. In addition, the Company added 8.0 MMBbls due to positive revisions. The positive revision of 8.0 MMBbls was due to positive revision of 3.0 MMBbls due to price and positive revisions of 5.0 MMBbls due to performance.

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, 2022, 2021 and 2020.

| | International | | | |
|---|---|---|---|---|
| ***(In thousands)*** | **Gabon** | **Egypt** | **Canada** | **Total** |
| **Year Ended December 31, 2022** | | | | |
| Future cash inflows | **$ 1,035,667** | **$ 729,236** | **$ 506,247** | **$ 2,271,150** |
| Future production costs | **(450,639)** | **(273,260)** | **(135,082)** | **(858,981)** |
| Future development costs (1) | **(58,057)** | **(12,079)** | **(69,346)** | **(139,482)** |
| Future income tax expense | **(248,024)** | **(146,835)** | **—** | **(394,859)** |
| Future net cash flows | **278,947** | **297,062** | **301,819** | **877,828** |
| Discount to present value at 10% annual rate | **(34,520)** | **(70,174)** | **(148,669)** | **(253,363)** |
| Standardized measure of discounted future net cash flows | **$ 244,427** | **$ 226,888** | **$ 153,150** | **$ 624,465** |
| **Year Ended December 31, 2021** | | | | |
| Future cash inflows | $ 782,006 | $ — | $ — | $ 782,006 |
| Future production costs | (416,819) | — | — | (416,819) |
| Future development costs (1) | (128,984) | — | — | (128,984) |
| Future income tax expense | (116,637) | — | — | (116,637) |
| Future net cash flows | 119,566 | — | — | 119,566 |
| Discount to present value at 10% annual rate | (20,308) | — | — | (20,308) |
| Standardized measure of discounted future net cash flows | $ 99,258 | $ — | $ — | $ 99,258 |
| **Year Ended December 31, 2020** | | | | |
| Future cash inflows | $ 138,328 | $ — | $ — | $ 138,328 |
| Future production costs | (99,418) | — | — | (99,418) |
| Future development costs (1) | (10,605) | — | — | (10,605) |
| Future income tax expense | (13,921) | — | — | (13,921) |
| Future net cash flows | 14,384 | — | — | 14,384 |
| Discount to present value at 10% annual rate | 348 | — | — | 348 |
| Standardized measure of discounted future net cash flows | $ 14,732 | $ — | $ — | $ 14,732 |

(1) Includes costs expected to be incurred to abandon the properties, where applicable.

International income taxes represent amounts payable to the Government of Gabon 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, | | |
|---|---|---|---|
| | **2022** | 2021 | 2020 |
| | | *(in thousands)* | |
| Balance at beginning of period | **$ 99,258** | $ 14,733 | $ 70,431 |
| Sales of crude oil and natural gas, net of production costs | **(233,421)** | (118,358) | (29,878) |
| Net changes in prices and production costs | **264,804** | 126,668 | (53,388) |
| Extensions and discoveries | **—** | — | 10,059 |
| Revisions of previous quantity estimates | **95,623** | 158,213 | (10,885) |
| Purchases | **415,385** | 9,285 | — |
| Changes in estimated future development costs | **(23,243)** | (39,969) | 1,195 |
| Development costs incurred during the period | **101,495** | 2,629 | 731 |
| Accretion of discount | **9,926** | 2,752 | 10,086 |
| Net change of income taxes | **(121,490)** | (60,218) | 17,636 |
| Change in production rates (timing) and other | **16,128** | 3,523 | (1,254) |
| Balance at end of period | **$ 624,465** | $ 99,258 | $ 14,733 |

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 guidelines of the SEC, estimates of future net cash flow from the properties and the present value thereof are made using an unweighted, arithmetic average of the first-day-of-the-month price for each of the 12 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 2022, the average of such prices reflected a 45% increase during the year and were $100.35 per Bbl for crude oil from Gabon when compared to the average of such prices for 2021 of $69.10 per Bbl for crude oil from Gabon. Prices were between $84.76 and $85.65 per Bbl for crude oil from Egypt and $89.61 per Bbl for crude oil from Canada.

For 2022, the adjusted average price for our reserves associated with natural gas was $4.13 per MCF, $12.77 per Bbl for Ethane, $40.27 per Bbl for propane, $43.85 per Bbl for butane and $91.57 per Bbl for condensates.

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 (see discussion in Note 7 above).

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 prepared 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, 2022, the Company has no 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.

## Board of Directors

**Andrew L. Fawthrop**
Chairman of the Board

**George Maxwell**
Chief Executive Officer and Director

**David Cook**
Director[1]

**Edward LaFehr**
Director

**Timothy Marchant**
Director[1]

**Fabrice Nze-Bekale**
Director

**Cathy Stubbs**
Director

## Corporate Officers

**George Maxwell**
Chief Executive Officer and Director

**Ronald Bain**
Chief Financial Officer

**Thor Pruckl**
Chief Operating Officer

**Matthew Powers**
Executive Vice President and General Counsel

**Jason J. Doornik**
Chief Accounting Officer and Controller

**Julie J. Ray**
Vice President of Treasury

### Annual Meeting

The Annual Meeting of Shareholders of VAALCO Energy, Inc. will be held at the Houston Hilton Westchase, 9999 Westheimer Road, Houston, Texas 77042 on June 8, 2023 at 8:30 am central time.

If unforeseen circumstances arise, VAALCO may decide to hold the meeting solely by means of remote communication (i.e., a virtual-only meeting). If that occurs, VAALCO will issue a press release announcing the decision and post additional information on its website at www.vaalco.com.

### Stock Exchanges

The Company's Common Stock is listed on the New York Stock Exchange and the London Stock Exchange and traded under the symbol "EGY."

### Investor Relations

Requests for additional information or copies of the Company's Form 10-K filed with the Securities and Exchange Commission should be directed to:

VAALCO Energy, Inc.
Investor Relations
9800 Richmond Avenue
Suite 700
Houston, Texas 77042

### Company Website

Information related to Company activities, financials and SEC filings is available at the Company website www.VAALCO.com

### Transfer Agent

Communications concerning common stock transfer requirements, lost certificates or changes of address should be directed to:

Computershare
462 South 4th Street, Suite 1600
Louisville, KY 40202
1-800-736-3001 (US, Canada, Puerto Rico)
1-781-575-3100 (Non-US)

### Independent Auditors

BDO USA, LLP
Houston, Texas

### Corporate Office

9800 Richmond Avenue
Suite 700
Houston, Texas 77042

### Branch Offices

**VAALCO Gabon S.A.**
B.P. 1335
Port Gentil, Gabon

**VAALCO Equatorial Guinea**
Office 2-1, 3rd Floor, Energy Square
Autovia Aeropuerto - Ela Nguema
Malabo II, Equatorial Guinea

**TransGlobe Egypt**
6 Badr Towers
Ring Road Maadi
Cairo, Egypt

**TransGlobe Canada**
900, 444 – 5th Avenue S.W.
Calgary Alberta, Canada T2P 2T8

[1] Not standing for re-election in 2023 Annual Meeting of Shareholders

VAALCO Energy, Inc. has included, as Exhibits 31 and 32 to its 2022 Annual Report on Form 10-K filed with the Securities and Exchange Commission, certificates of the Chief Executive Officer and Chief Financial Officer of the Corporation regarding the quality of the Corporation's public disclosure. The Corporation has also submitted to the New York Stock Exchange (NYSE) a certification of the CEO certifying that he is not aware of any violation by the Corporation of NYSE corporate governance listing standards.

VAALCO ENERGY, INC.

9800 Richmond Avenue, Suite 700
Houston, Texas 77042
713.623.0801
**vaalco.com**