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, 2023

☐ **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: 001-35167

Kosmos Energy Ltd.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**98-0686001** (I.R.S. Employer Identification No.)
8176 Park Lane **Dallas, Texas** (Address of principal executive offices)	**75231** (Zip Code)

Registrant's telephone number, including area code: **+1 214 445 9600**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol	Name of each exchange on which registered:
Common Stock $0.01 par value	KOS	New York Stock Exchange London Stock Exchange

Securities registered pursuant to Section 12(g) of the 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 15(d) 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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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 and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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 (Do not check if a smaller reporting company)	☐	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 ☒

The aggregate market value of the voting and non-voting common stock held by non-affiliates, based on the per-share closing price of the registrant's common stock as of the last business day of the registrant's most recently completed second fiscal quarter was $2,698,047,415.

The number of the registrant's Common Stock outstanding as of February 22, 2024 was 471,502,543.

DOCUMENTS INCORPORATED BY REFERENCE

Part III, Items 10-14, is incorporated by reference from the Proxy Statement for the Annual Meeting of Shareholders which will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2023.

Certain exhibits previously filed with the Securities and Exchange Commission are incorporated by reference into Part IV of this report.

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Unless otherwise stated in this report, references to "Kosmos," "we," "us" or "the company" refer to Kosmos Energy Ltd. and its subsidiaries. In addition, we have provided definitions for some of the industry terms used in this report in the "Glossary and Selected Abbreviations" beginning on page 4.

KOSMOS ENERGY LTD.
GLOSSARY AND SELECTED ABBREVIATIONS

The following are abbreviations and definitions of certain terms that may be used in this report. Unless listed below, all defined terms under Rule 4-10(a) of Regulation S-X shall have their statutorily prescribed meanings.

"2D seismic data"	Two-dimensional seismic data, serving as interpretive data that allows a view of a vertical cross-section beneath a prospective area.
"3D seismic data"	Three-dimensional seismic data, serving as geophysical data that depicts the subsurface strata in three dimensions. 3D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than 2D seismic data.
"ANP-STP"	Agencia Nacional Do Petroleo De Sao Tome E Principe.
"API"	A specific gravity scale, expressed in degrees, that denotes the relative density of various petroleum liquids. The scale increases inversely with density. Thus lighter petroleum liquids will have a higher API than heavier ones.
"ASC"	Financial Accounting Standards Board Accounting Standards Codification.
"ASU"	Financial Accounting Standards Board Accounting Standards Update.
"Barrel" or "Bbl"	A standard measure of volume for petroleum corresponding to approximately 42 gallons at 60 degrees Fahrenheit.
"BBbl"	Billion barrels of oil.
"BBoe"	Billion barrels of oil equivalent.
"Bcf"	Billion cubic feet.
"Boe"	Barrels 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.
"BOEM"	Bureau of Ocean Energy Management.
"Boepd"	Barrels of oil equivalent per day.
"Bopd"	Barrels of oil per day.
"BP"	BP p.l.c. and related subsidiaries.
"Bwpd"	Barrels of water per day.
"Corporate Revolver"	Prior to March 31, 2022, this term refers to the Revolving Credit Facility Agreement dated November 23, 2012 (as amended or as amended and restated from time to time), and on or after March 31, 2022, this term refers to the new Revolving Credit Facility Agreement dated March 31, 2022 (as amended or as amended and restated from time to time).
"COVID-19"	Coronavirus disease 2019.
"Debt cover ratio"	The "debt cover ratio" is broadly defined, for each applicable calculation date, as the ratio of (x) total long-term debt less cash and cash equivalents and restricted cash, to (y) the aggregate EBITDAX (see below) of the Company for the previous twelve months.
"Developed acreage"	The number of acres that are allocated or assignable to productive wells or wells capable of production.
"Development"	The phase in which an oil or natural gas field is brought into production by drilling development wells and installing appropriate production systems.
"DST"	Drill stem test.
"Dry hole" or "Unsuccessful well"	A well that has not encountered a hydrocarbon bearing reservoir expected to produce in commercial quantities.
"DT"	Deepwater Tano.
"EBITDAX"	Net income (loss) plus (i) exploration expense, (ii) depletion, depreciation and amortization expense, (iii) equity-based compensation expense, (iv) unrealized (gain) loss on commodity derivatives (realized losses are deducted and realized gains are added back), (v) (gain) loss on sale of oil and gas properties, (vi) interest (income) expense, (vii) income taxes, (viii) loss on extinguishment of debt, (ix) doubtful accounts expense and (x) similar other material items which management believes affect the comparability of operating results.
"ESG"	Environmental, social, and governance.
"ESP"	Electric submersible pump.

"E&P"	Exploration and production.
"Facility"	Facility agreement dated March 28, 2011 (as amended or as amended and restated from time to time).
"FASB"	Financial Accounting Standards Board.
"Farm-in"	An agreement whereby a party acquires a portion of the participating interest in a block from the owner of such interest, usually in return for cash and/or for taking on a portion of future costs or other performance by the assignee as a condition of the assignment.
"Farm-out"	An agreement whereby the owner of the participating interest agrees to assign a portion of its participating interest in a block to another party for cash and/or for the assignee taking on a portion of future costs and/or other work as a condition of the assignment.
"FEED"	Front End Engineering Design.
"Field life cover ratio"	The "field life cover ratio" is broadly defined, for each applicable forecast period, as the ratio of (x) the forecasted net present value of net cash flow through depletion plus the net present value of the forecast of certain capital expenditures incurred in relation to the Ghana and Equatorial Guinea assets, to (y) the aggregate loan amounts outstanding under the Facility.
"FLNG"	Floating liquefied natural gas.
"FPS"	Floating production system.
"FPSO"	Floating production, storage and offloading vessel.
"GAAP"	Generally Accepted Accounting Principles in the United States of America.
"GEPetrol"	Guinea Equatorial De Petroleos.
"GHG"	Greenhouse gas.
"GJFFDP"	Greater Jubilee Full Field Development Plan.
"GNPC"	Ghana National Petroleum Corporation.
"GoM Term Loan"	Senior Secured Term Loan Credit Agreement dated September 30, 2020.
"Greater Tortue Ahmeyim"	Ahmeyim and Guembeul discoveries.
"GTA UUOA"	Unitization and Unit Operating Agreement covering the Greater Tortue Ahmeyim Unit.
"HLS"	Heavy Louisiana Sweet.
"Jubilee UUOA"	Unitization and Unit Operating Agreement covering the Jubilee Unit.
"Interest cover ratio"	The "interest cover ratio" is broadly defined, for each applicable calculation date, as the ratio of (x) the aggregate EBITDAX (see above) of the Company for the previous twelve months, to (y) interest expense less interest income for the Company for the previous twelve months.
"LNG"	Liquefied natural gas.
"Loan life cover ratio"	The "loan life cover ratio" is broadly defined, for each applicable forecast period, as the ratio of (x) net present value of forecasted net cash flow through the final maturity date of the Facility plus the net present value of forecasted capital expenditures incurred in relation to the Ghana and Equatorial Guinea assets to (y) the aggregate loan amounts outstanding under the Facility.
"LIBOR"	London Interbank Offered Rate
"LSE"	London Stock Exchange.
"LTIP"	Long Term Incentive Plan.
"MBbl"	Thousand barrels of oil.
"MBoe"	Thousand barrels of oil equivalent.
"Mcf"	Thousand cubic feet of natural gas.
"Mcfpd"	Thousand cubic feet per day of natural gas.
"MMBbl"	Million barrels of oil.
"MMBoe"	Million barrels of oil equivalent.
"MMBtu"	Million British thermal units.
"MMcf"	Million cubic feet of natural gas.

"MMcfd"	Million cubic feet per day of natural gas.
"MMTPA"	Million metric tonnes per annum.
"Natural gas liquid" or "NGL"	Components of natural gas that are separated from the gas state in the form of liquids. These include propane, butane, and ethane, among others.
"Net Debt"	Total long-term debt less cash and cash equivalents and total restricted cash.
"NYSE"	New York Stock Exchange.
"Petroleum contract"	A contract in which the owner of hydrocarbons gives an E&P company temporary and limited rights, including an exclusive option to explore for, develop, and produce hydrocarbons from the lease area.
"Petroleum system"	A petroleum system consists of organic material that has been buried at a sufficient depth to allow adequate temperature and pressure to expel hydrocarbons and cause the movement of oil and natural gas from the area in which it was formed to a reservoir rock where it can accumulate.
"Plan of development" or "PoD"	A written document outlining the steps to be undertaken to develop a field.
"Productive well"	An exploratory or development well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.
"Prospect(s)"	A potential trap that may contain hydrocarbons and is supported by the necessary amount and quality of geologic and geophysical data to indicate a probability of oil and/or natural gas accumulation ready to be drilled. The five required elements (generation, migration, reservoir, seal and trap) must be present for a prospect to work and if any of these fail neither oil nor natural gas may be present, at least not in commercial volumes.
"Proved reserves"	Estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be economically recoverable in future years from known reservoirs under existing economic and operating conditions, as well as additional reserves expected to be obtained through confirmed improved recovery techniques, as defined in SEC Regulation S-X 4-10(a)(2).
"Proved developed reserves"	Those proved reserves that can be expected to be recovered through existing wells and facilities and by existing operating methods.
"Proved undeveloped reserves"	Those proved reserves that are expected to be recovered from future wells and facilities, including future improved recovery projects which are anticipated with a high degree of certainty in reservoirs which have previously shown favorable response to improved recovery projects.
"RSC"	Ryder Scott Company, L.P.
"SOFR"	Secured Overnight Financing Rate
"SEC"	Securities and Exchange Commission.
"7.125% Senior Notes"	7.125% Senior Notes due 2026.
"7.750% Senior Notes"	7.750% Senior Notes due 2027.
"7.500% Senior Notes"	7.500% Senior Notes due 2028.
"Shelf margin"	The path created by the change in direction of the shoreline in reaction to the filling of a sedimentary basin.
"Shell"	Royal Dutch Shell and related subsidiaries.
"SMH"	*Societe Mauritanienne des Hydrocarbures*
"Stratigraphy"	The study of the composition, relative ages and distribution of layers of sedimentary rock.
"Stratigraphic trap"	A stratigraphic trap is formed from a change in the character of the rock rather than faulting or folding of the rock and oil is held in place by changes in the porosity and permeability of overlying rocks.
"Structural trap"	A topographic feature in the earth's subsurface that forms a high point in the rock strata. This facilitates the accumulation of oil and gas in the strata.
"Structural-stratigraphic trap"	A structural-stratigraphic trap is a combination trap with structural and stratigraphic features.

"Submarine fan"	A fan-shaped deposit of sediments occurring in a deep water setting where sediments have been transported via mass flow, gravity induced, processes from the shallow to deep water. These systems commonly develop at the bottom of sedimentary basins or at the end of large rivers.
"TAG GSA"	TEN Associated Gas - Gas Sales Agreement.
"TEN"	Tweneboa, Enyenra and Ntomme.
"Three-way fault trap"	A structural trap where at least one of the components of closure is formed by offset of rock layers across a fault.
"Tortue Phase 1 SPA"	Greater Tortue Ahmeyim Agreement for a Long Term Sale and Purchase of LNG.
"Trap"	A configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not migrate.
"Trident"	Trident Energy.
"Undeveloped acreage"	Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains discovered resources.
"WCTP"	West Cape Three Points.

Cautionary Statement Regarding Forward-Looking Statements

This annual report on Form 10-K contains estimates and forward-looking statements, principally in "Item 1. Business," "Item 1A. Risk Factors" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations." Our estimates and forward-looking statements are mainly based on our current expectations and estimates of future events and trends, which affect or may affect our businesses and operations. Although we believe that these estimates and forward-looking statements are based upon reasonable assumptions, they are subject to several risks and uncertainties and are made in light of information currently available to us. Many important factors, in addition to the factors described in our annual report on Form 10-K, may adversely affect our results as indicated in forward-looking statements. You should read this annual report on Form 10-K and the documents that we have filed as exhibits hereto completely and with the understanding that our actual future results may be materially different from what we expect. Our estimates and forward-looking statements may be influenced by the following factors, among others:

- the impact of a potential regional or global recession, inflationary pressures and other varying macroeconomic conditions on us and the overall business environment;
- the impacts of Russia's war in Ukraine and potential instability in the Middle East and the effects these events have on the oil and gas industry as a whole, including increased volatility with respect to oil, natural gas and NGL prices and operating and capital expenditures;
- our ability to find, acquire or gain access to other discoveries and prospects and to successfully develop and produce from our current discoveries and prospects;
- uncertainties inherent in making estimates of our oil and natural gas data;
- the successful implementation of our and our block partners' prospect discovery and development and drilling plans;
- projected and targeted capital expenditures and other costs, commitments and revenues;
- termination of or intervention in concessions, rights or authorizations granted to us by the governments of the countries in which we operate (or their respective national oil companies) or any other federal, state or local governments or authorities;
- our dependence on our key management personnel and our ability to attract and retain qualified technical personnel;
- the ability to obtain financing and to comply with the terms under which such financing may be available;
- the volatility of oil, natural gas and NGL prices, as well as our ability to implement hedges addressing such volatility on commercially reasonable terms;
- the availability, cost, function and reliability of developing appropriate infrastructure around and transportation to our discoveries and prospects;
- the availability and cost of drilling rigs, production equipment, supplies, personnel and oilfield services;
- other competitive pressures;
- potential liabilities inherent in oil and natural gas operations, including drilling and production risks and other operational and environmental risks and hazards;
- current and future government regulation of the oil and gas industry, applicable monetary/foreign exchange sectors or regulation of the investment in or ability to do business with certain countries or regimes;
- cost of compliance with laws and regulations;
- changes in, or new, environmental, health and safety or climate change or GHG laws, regulations and executive orders, or the implementation, or interpretation, of those laws, regulations and executive orders;
- adverse effects of sovereign boundary disputes in the jurisdictions in which we operate;
- environmental liabilities;

- geological, geophysical and other technical and operations problems including drilling and oil and gas production and processing;
- military operations, civil unrest, outbreaks of disease, terrorist acts, wars or embargoes;
- the cost and availability of adequate insurance coverage and whether such coverage is enough to sufficiently mitigate potential losses and whether our insurers comply with their obligations under our coverage agreements;
- our vulnerability to severe weather events, including, but not limited to, tropical storms and hurricanes, and the physical effects of climate change;
- our ability to meet our obligations under the agreements governing our indebtedness;
- the availability and cost of financing and refinancing our indebtedness;
- the amount of collateral required to be posted from time to time in our hedging transactions, letters of credit, performance bonds and other secured debt;
- our ability to obtain surety or performance bonds on commercially reasonable terms;
- the result of any legal proceedings, arbitrations, or investigations we may be subject to or involved in;
- our success in risk management activities, including the use of derivative financial instruments to hedge commodity and interest rate risks; and
- other risk factors discussed in the "Item 1A. Risk Factors" section of this annual report on Form 10-K.

The words "believe," "may," "will," "aim," "estimate," "continue," "anticipate," "intend," "expect," "plan" and similar words are intended to identify estimates and forward-looking statements. Estimates and forward-looking statements speak only as of the date they were made, and, except to the extent required by law, we undertake no obligation to update or to review any estimate and/or forward-looking statement because of new information, future events or other factors. Estimates and forward-looking statements involve risks and uncertainties and are not guarantees of future performance. As a result of the risks and uncertainties described above, the estimates and forward-looking statements discussed in this annual report on Form 10-K might not occur, and our future results and our performance may differ materially from those expressed in these forward-looking statements due to, including, but not limited to, the factors mentioned above. Because of these uncertainties, you should not place undue reliance on these forward-looking statements.

PART I

Item 1. Business

General

Kosmos is a full-cycle, deepwater, independent oil and gas exploration and production company focused along the offshore Atlantic Margins. Our key assets include production offshore Ghana, Equatorial Guinea and the U.S. Gulf of Mexico, as well as world-class gas projects offshore Mauritania and Senegal. We also pursue a proven basin exploration program in Equatorial Guinea and the U.S. Gulf of Mexico. Kosmos is listed on the NYSE and LSE and is traded under the ticker symbol KOS.

Kosmos was founded in 2003 to find oil in under-explored or overlooked parts of West Africa. In its relatively brief history, we have successfully opened two new hydrocarbon basins through the discovery of the Jubilee Field offshore Ghana in 2007 and the Greater Tortue Ahmeyim Field in 2015 (which includes the Ahmeyim and Guembeul-1 discovery wells offshore Mauritania and Senegal in 2015 and 2016, respectively). Jubilee was one of the largest oil discoveries worldwide in 2007 and is considered one of the largest finds offshore West Africa discovered during that decade. The Greater Tortue Ahmeyim discovery was one of the largest natural gas discoveries worldwide in 2015 and is one of the largest gas discoveries ever offshore West Africa.

Over the past few years, our business strategy has evolved to focus on enhancing production through infill drilling and well work, infrastructure-led exploration, as well as value-accretive acquisitions. This strategic evolution was initially enabled by our acquisition of the Ceiba Field and Okume Complex assets offshore Equatorial Guinea in 2017, together with access to surrounding exploration licenses, and bolstered by the 2018 acquisition of Deep Gulf Energy, a deepwater company operating in the U.S. Gulf of Mexico, which further enhanced our production, exploitation and infrastructure-led exploration capabilities. Most recently, we have demonstrated this infrastructure-led exploration strategy by the Winterfell and Tiberius discoveries in the U.S. Gulf of Mexico in 2021 and 2023, respectively. We have demonstrated the value-accretive acquisitions strategy with the acquisition of additional interests in the Jubilee and TEN fields offshore Ghana in 2021, the Kodiak and Winterfell fields in the U.S. Gulf of Mexico in 2022, and the Yakaar and Teranga fields in Senegal in 2023.

Our Business Strategy

As a full-cycle deepwater E&P company, our mission is to safely deliver production and free cash flow from a portfolio rich in opportunities through a disciplined allocation of capital and optimal portfolio management for the benefit of our shareholders and stakeholders. As a responsible company, we are working to supply the energy the world needs today, find and develop affordable and cleaner energy to advance the energy transition, and be a force for good in our host countries.

Our business strategy is designed to accomplish this mission by focusing on three key objectives: (1) maximize the value of our producing assets; (2) progress our discovered resources toward project sanction and into proved reserves, production, and cash flow through efficient appraisal, development and exploitation; and (3) add new lower carbon resources through an efficient low cost exploration program in proven basins or acquisitions. We are focused on increasing production, cash flows and reserves from our producing assets in Equatorial Guinea, Ghana, and the U.S. Gulf of Mexico as well as executing our appraisal and development efforts in the U.S. Gulf of Mexico and Equatorial Guinea. In Mauritania and Senegal, we are progressing our Greater Tortue Ahmeyim development with first gas for Phase 1 of the project targeted in the third quarter of 2024, while advancing Phase 2 of the development, as well as advancing phased development concepts for the Yakaar and Teranga discoveries in Senegal and the BirAllah and Orca discoveries in Mauritania. In addition, our portfolio contains an inventory of infrastructure-led exploration prospects, which we plan to continue to mature and high-grade for future drilling and development, providing us access to additional high return growth potential in the coming years. We are also working with our partners and host governments on projects to reduce the carbon intensity of our production assets, such as the elimination of routine flaring in Ghana and Equatorial Guinea.

Grow cash flow, proved reserves and production through exploitation and development with increasing exposure to natural gas and LNG

We plan to grow cash flow, proved reserves and production by further exploiting our fields offshore Equatorial Guinea, Ghana, and the U.S. Gulf of Mexico. In Equatorial Guinea, our activity set is expanding beyond production optimization projects, such as utilizing electrical submersible pumps, to include development drilling and infrastructure-led exploration which, if successful, can be brought online quickly via subsea tieback to existing infrastructure. In Ghana, we plan to continue drilling additional development wells at the Jubilee Field in the near term. In the U.S. Gulf of Mexico, we plan to continue development drilling and well work in existing fields. We are also executing the Winterfell Field Development Plan with first production for Phase 1A of the project targeted for early in the second quarter of 2024 with future phases to follow. In addition, we are working with partners to progress development concepts for the Tiberius discovery which was made in 2023. The development of Phase 1 of the Greater Tortue Ahmeyim development offshore Mauritania and Senegal continues to make good progress. Beyond the Phase 1 development of Greater Tortue Ahmeyim, growth is also expected to be realized through additional development phases of Greater Tortue Ahmeyim and through development of the Yakaar and Teranga natural gas discoveries in Senegal and the BirAllah and Orca discoveries in Mauritania. During 2024, we plan to continue to mature development concepts for our existing discoveries in Mauritania, Senegal, the U.S. Gulf of Mexico and Equatorial Guinea.

Focus on optimally developing our discoveries to initial production

Our approach to development is designed to deliver first production on an accelerated timeline, with low cost, lower carbon solutions, where we can leverage early learnings to improve future outcomes and maximize returns. In certain circumstances, we believe a phased approach can be employed to optimize full-field development. A phased approach facilitates refinement of the development plans based on experience gained in initial phases of production and by leveraging existing infrastructure as subsequent phases of development are implemented. Production and reservoir performance from the initial phases are monitored closely to determine the most efficient and effective techniques to maximize the recovery of reserves and returns. Other benefits include minimizing upfront capital costs, reducing execution risks through smaller initial infrastructure requirements, and enabling cash flow from the initial phases of production to fund a portion of capital costs for subsequent phases. Our development of the Jubilee Field is an example of this approach. The Greater Tortue Ahmeyim development is also being developed in a phased approach, consistent with our business strategy. This is anticipated to result in first gas approximately nine years after initial discovery. Finally, our approach to discoveries in the U.S. Gulf of Mexico is to develop them via subsea tie-back to existing host facilities with spare capacity, which reduces development costs and the average timeline to first production. The Winterfell discovery (2021) and subsequent appraisal success (early 2022) is an example of this approach, with development expected to deliver first production in around three years after initial discovery. In addition, we anticipate that the Tiberius discovery (2023) will follow a similar approach.

Apply our entrepreneurial culture, which fosters innovation and creativity, to continue our successful exploration and development program

Our employees are critical to the success of our business strategy, and we have created an environment that enables them to focus their knowledge, skills and experience on finding, developing and producing new fields and optimizing production from existing fields. Culturally, we have an open, team-oriented work environment that fosters entrepreneurial, creative and contrarian thinking. This approach enables us to fully consider and understand both risk and reward, as well as deliberately and collectively pursue ideas that create and maximize value and free cash flow.

We are led by an experienced management team with a successful track record. Our management team members average over 28 years of industry experience and have participated in discovering, developing, and maximizing the value of multiple large-scale upstream projects around the world. Our experience, industry relationships and technical expertise are our core competitive strengths and are crucial to our success.

Our returns focused exploration approach

Our exploration activity, which is deeply rooted in a fundamental, geologic approach, is focused on proven basins with high-graded infrastructure-led prospects and material play extension opportunities. We target specific areas with sufficient size to manage exploration risks and provide scale should the exploration concept prove successful. We also look for: (i) long-term contract durations to enable the “right” exploration program to be executed, (ii) play type diversity to provide multiple exploration concept options, (iii) prospect dependency to enhance the chance of replicating success, and (iv) attractive fiscal terms to maximize the commercial viability of discovered hydrocarbons. Alongside the subsurface analysis, Kosmos gains a thorough understanding of the “above-ground” dynamics in each of the countries in which we operate, which may influence a particular country’s relative desirability from an overall oil and natural gas operating and risk adjusted return perspective.

Our approach is aimed at areas where we have existing production and where there is sufficient infrastructure capacity to enable the development of new discoveries via subsea tieback. Acquisition of the Ceiba Field and Okume Complex in Equatorial Guinea and assets in the U.S. Gulf of Mexico have added high-quality prospectivity to our inventory of infrastructure-led exploration opportunities given their attractive acreage positions within proximity of existing infrastructure with excess capacity available. Existing infrastructure allows us to shorten the time cycle from discovery to first production, lower the capital requirements and increase the returns.

Pursuing value accretive, opportunistic transactions that meet our strategic and financial objectives

Since 2017, we have completed three separate significant acquisitions of oil and natural gas producing properties for total value of approximately $2.0 billion dollars, as of the effective date of the acquisitions. These acquisitions were targeted to increase and complement our existing properties, providing production diversification while increasing the quality of investment opportunities in our portfolio. Our experienced team of management and technical professionals intend to continue identifying, evaluating and pursuing transactions involving oil and natural gas properties that are complementary to our core operating areas, as well as opportunities in other basins where we can apply our existing knowledge, expertise and relationships to create shareholder value. Our focus is on transactions where we can leverage our operational experience and expertise to provide productivity and cost improvements, invest in additional developmental opportunities in such assets and implement an infrastructure-led exploration program for nearby prospects.

Secure a premium license to operate through industry-leading ESG performance

We recognize that advancing the societies in which we work and operating in a manner that protects the environment is critical for creating long-term returns. We aim to continuously improve our ESG credentials by working with a range of stakeholders, including shareholders, partners, suppliers, host governments and civil society organizations.

We aim to act as a force for good by advancing a just energy transition in our host countries and communities – namely by supporting economic and social development in the places where we work through supplying affordable and cleaner energy while lowering emissions. We use the United Nations Sustainable Development Goals to understand how our activities promote economic and social progress in host countries. Our Business Principles reflect our shared values as a company, define how we conduct our business and set the standards to which we hold ourselves accountable. Our Business Principles are supported by more detailed policies, procedures, and management systems. Each year, we report on our ESG approach and performance in our Sustainability Report and on our website.

Most recently, we have focused on evaluating the costs, benefits, risks, and opportunities that climate change and the global energy transition may present to our business and integrating them into our business strategy. As part of this effort, the Health, Safety, Environment and Sustainability Board Committee oversees our response to climate change. A Chief Executive Officer led, cross functional, Climate Change Task force manages climate-related risks and opportunities, and is responsible for implementing our climate change strategy. We have published a Climate Risk and Resilience Report that adheres to the recommendations of the Task Force on Climate-related Disclosure (“TCFD”). The report reviews how we are identifying and managing climate-related risks and opportunities across four categories: Governance, Strategy, Risk Management, and Metrics and Targets. The report sets forth a scenario analysis demonstrating the resilience of our portfolio under a scenario aligned with the Paris Agreement’s goals, and our goal to achieve operated Scope 1 and Scope 2 carbon neutrality by 2030 or sooner. We first achieved this goal in 2021 and have identified a pathway to help maintain it through continual monitoring of emissions, assessment of emission reduction opportunities, and, for residual emissions, investment in high-quality carbon offset projects. We recognize most of our production, and the associated GHG emissions, is derived from assets in which we are non-operating partners. In 2023 we set a target to reduce absolute Scope 1 equity emissions 25% by 2026, compared to a 2022 baseline. This tangible, near-term target addresses the need to manage the climate impact of our portfolio and we are working with our partners to assess and implement emission reduction opportunities with minimal impact to production.

Maintain financial discipline

Execution of our strategy requires us to maintain a conservative financial approach with a strong balance sheet, ample liquidity, and a commitment to low leverage. As of December 31, 2023, our liquidity was approximately $670 million.

Additionally, we use derivative instruments to partially limit our exposure to fluctuations in oil prices. We have an active commodity hedging program where we aim to hedge a portion of our anticipated sales volumes on a one to two year rolling basis, with the goal to protect against the downside price scenario while still retaining partial exposure to the upside. As of January 31, 2024, we have hedged positions covering approximately 9.2 million barrels of oil production in 2024 and are now looking to protect our exposure to oil prices in 2025. We also maintain insurance to partially protect against loss of production revenues from certain of our producing assets.

Operations by Geographic Area

We currently have operations in Africa and the U.S. Gulf of Mexico. Presently, our operating revenues are generated from our operations offshore Ghana, Equatorial Guinea, and the U.S. Gulf of Mexico. The following tables provide a summary of certain key 2023 data for our geographic areas.

		Sales Volumes (Net to Kosmos)				Average Sales Price						
Geographic Area	Percentage of BOE Sales Volumes	Oil (MMBbls)	NGL	Gas (Bcf)	Total (MMBoe)	Oil (per Bbl)	NGL	Gas (per Bcf)	Total (per Boe)	Revenue (in Thousands)	Production costs per Boe(3)	Depletion, depreciation and amortization per Boe
For the year ended December 31, 2023												
Jubilee	54 %	11.4	—	5.8	12.4	83.33	—	3.74	78.62	$ 974,627	8.74	17.30
TEN	7 %	1.0	—	3.9	1.7	85.72	—	0.64	53.06	87,855	40.40	15.97
Ghana	61 %	12.4	—	9.7	14.1	83.52	—	2.48	75.61	$ 1,062,482	12.47	17.15
Equatorial Guinea	15 %	3.4	—	—	3.4	78.71	—	—	78.71	267,494	33.67	15.23
Mauritania/Senegal	—	—	—	—	—	—	—	—	—	—	—	—
U.S. Gulf of Mexico	24 %	4.6	0.4	4.0	5.6	77.41	20.61	2.79	66.29	371,632	17.91	26.67
Total	100 %	20.4	0.4	13.7	23.1	81.35	20.61	2.57	73.80	$ 1,701,608	16.92	19.30
For the year ended December 31, 2022												
Jubilee	49 %	11.4	—	—	11.4	$ 101.23	—	—	$ 101.23	$ 1,162,416	$ 9.93	$ 20.32
TEN	9 %	2.0	—	—	2.0	96.83	—	—	96.83	188,546	47.48	28.57
Ghana(1)	58 %	13.4	—	—	13.4	$ 100.59	—	—	$ 100.59	$ 1,350,962	$ 15.37	$ 21.52
Equatorial Guinea	14 %	3.3	—	—	3.3	104.24	—	—	104.24	346,783	27.23	16.16
Mauritania/Senegal	—	—	—	—	—	—	—	—	—	—	—	—
U.S. Gulf of Mexico	28 %	5.3	0.4	4.1	6.4	95.80	34.37	7.24	86.09	547,610	16.50	24.12
Total	100 %	22.0	0.4	4.1	23.1	$ 100.00	$ 34.37	$ 7.24	$ 97.13	$ 2,245,355	$ 17.39	$ 21.55
For the year ended December 31, 2021												
Jubilee	35 %	7.0	—	—	7.0	$ 71.21	—	—	$ 71.21	$ 500,541	$ 11.12	$ 23.93
TEN	10 %	2.0	—	—	2.0	73.82	—	—	73.82	143,691	37.47	37.30
Ghana(2)	45 %	9.0	—	—	9.0	$ 71.77	—	—	$ 71.77	$ 644,232	$ 16.83	$ 26.84
Equatorial Guinea	19 %	3.7	—	—	3.7	70.39	—	—	70.39	260,520	25.13	15.26
Mauritania/Senegal	—	—	—	—	—	—	—	—	—	—	—	—
U.S. Gulf of Mexico	36 %	5.8	0.5	4.9	7.2	67.35	28.62	3.85	59.57	427,261	14.21	23.44
Total	100 %	18.5	0.5	4.9	19.9	$ 70.10	$ 28.62	$ 3.85	$ 67.10	$ 1,332,013	$ 17.44	$ 23.54

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(1) Our sales volumes during 2022 includes activity related to the interest pre-empted by Tullow prior to the March 17, 2022 closing date of the Tullow pre-emption transaction.

(2) Our sales volumes during 2021 includes activity related to our acquisition of additional interests in Ghana from October 13, 2021, the acquisition date, through December 31, 2021. Our year-end proved reserves also include the additional interests acquired.

(3) Substantially all NGLs and natural gas sales are associated production from our oil wells and, therefore, production costs metrics are presented under a common unit of measure.

Information about our deepwater fields is summarized in the following table.

Fields	License		Kosmos Participating Interest		Operator	Stage	License Expiration
Ghana(1)							
Jubilee	WCTP/DT	(2)	38.6 %	(2)	Tullow	Production	2034/2036
TEN	DT		20.4 %	(4)	Tullow	Production	2036
U.S. Gulf of Mexico(1)							
Barataria	MC 521		22.5 %		Kosmos	Production	(8)
Big Bend	MC 697 / 698 / 742		5.3 %		QuarterNorth	Production	(8)
Gladden	MC 800		20.0 %		W&T	Production	(8)
Kodiak	MC 727 / 771		35.0 %		Kosmos	Production	(8)
Marmalard	MC 255 / 300		11.4 %		Murphy	Production	(8)
Nearly Headless Nick	MC 387		21.9 %		Murphy	Production	(8)
Danny Noonan	EC 381 / GB 506		30.0 %		Talos	Production	(8)
Odd Job	MC 214 / 215		Various	(5)	Kosmos	Production	(8)
SOB II	MC 431		11.8 %		Murphy	Production	(8)
S. Santa Cruz	MC 563		40.5 %		Kosmos	Production	(8)
Tornado	GC 281		35.0 %		Talos	Production	(8)
Winterfell	GC 943 / 944		25.0 %		Beacon	Development	(8)
Tiberius	KC 964		33.3 %		Kosmos	Appraisal	(8)
Mauritania							
Greater Tortue Ahmeyim(1)	Block C8	(3)	26.8 %		BP	Development	2049(9)
BirAllah	BirAllah		28.0 %	(6)	BP	Appraisal	2024
Orca	BirAllah		28.0 %	(6)	BP	Appraisal	2024
Senegal							
Greater Tortue Ahmeyim(1)	Saint Louis Offshore Profond	(3)	26.7 %		BP	Development	2044(10)
Teranga	Cayar Offshore Profond		90.0 %	(7)	Kosmos	Appraisal	2024
Yakaar	Cayar Offshore Profond		90.0 %	(7)	Kosmos	Appraisal	2024
Equatorial Guinea							
Ceiba Field and Okume Complex(1)	Block G		40.4 %		Trident	Production	2040
Asam	Block S		34.0 %		Kosmos	Appraisal	2024

(1) For information concerning our estimated proved reserves as of December 31, 2023, see “—Our Reserves.”

(2) The Jubilee Field straddles the boundary between the WCTP petroleum contract and the DT petroleum contract offshore Ghana. To optimize resource recovery in this field, we entered into the Jubilee UUOA in July 2009 with GNPC and the other block partners of each of these two blocks. The Jubilee UUOA governs the interests in and development of the Jubilee Field and created the Jubilee Unit from portions of the WCTP petroleum contract and the DT petroleum contract areas. The interest percentage is subject to redetermination of the participating interests in the Jubilee Field pursuant to the terms of the Jubilee UUOA. Our current paying interest on development activities in the Jubilee Field is 43.05%.

(3) The Greater Tortue Ahmeyim Unit, which includes the Ahmeyim discovery in Mauritania Block C8 and the Guembeul discovery in the Senegal Saint Louis Offshore Profond Block, straddles the border between Mauritania and Senegal. To optimize resource recovery in this field, we entered into the GTA UUOA in February 2019 with the governments of Mauritania and Senegal and the other block partners of each of these two blocks. The GTA UUOA governs interests in and development of the Greater Tortue Ahmeyim Field and created the Greater Tortue Ahmeyim Unit from portions of the Mauritania Block C8 and the Senegal Saint Louis Offshore Profond Block areas. These interest percentages are subject to redetermination of the participating interests in the Greater Tortue Ahmeyim Field pursuant to the terms of the GTA UUOA.

(4) Our paying interest on development activities in the TEN Fields is 22.8%.

(5) Our interests in blocks MC 214 and MC 215 are 61.1% and 54.9%, respectively.

(6) The Petroleum Contract covering the BirAllah and Orca discoveries contains provisions for back-in rights for the Government of Mauritania. Kosmos' participating interest in the Petroleum contract is currently 28.0% and this interest percentage does not give effect to the exercise of such back-in rights. Full election by SMH of their back-in rights would reduce Kosmos' participating interest to approximately 22.1%.

(7) PETROSEN has the right to increase its participating interest after final investment decision and issuance of an exploitation authorization to up to 35%. The interest percentage does not give effect to the exercise of such option.

(8) Our U.S. Gulf of Mexico blocks are held by production/operations, and the lease periods extend as long as production/governmental approved operations continue on the relevant block.

(9) License expiration date can be extended by an additional ten years subject to certain conditions being met.

(10) License expiration date can be extended by an additional twenty years subject to certain conditions being met.

Exploration License and Lease Areas

Country	Number of Blocks	Kosmos Average Participating Interest		Operator(s)	Current Phase Expiration Range	
Equatorial Guinea	4	54.5%	(1)	Kosmos, Panoro	2024 and 2026	
Mauritania	1	28.0%	(2)	BP	2024	
Sao Tome and Principe	1	58.9%	(3)	Kosmos	2024	
Senegal	1	90.0%	(4)	Kosmos	2024	
U.S. Gulf of Mexico	46	40.6%		Kosmos, Occidental, Beacon, LLOG, Murphy, QuarterNorth, Talos, W&T Offshore, Houston Energy	through 2033	(5)

(1) Should a commercial discovery be made, GEPetrol's 20% carried interest will convert to a 20% participating interest for all development and production operations.

(2) Full election by SMH of their back-in rights would reduce Kosmos' participating interest to approximately 22.1%. SMH will pay its portion of development and production costs in a commercial development on the block. The interest percentage does not give effect to the exercise of such options.

(3) ANP-STP's carried interest may be converted to a full participating interest at any time. ANP-STP will reimburse any costs, expenses and any amount incurred on its behalf prior to the election.

(4) PETROSEN has the right to increase its participating interest after final investment decision and issuance of an exploitation authorization to up to 35%. The interest percentage does not give effect to the exercise of such option.

(5) Our U.S. Gulf of Mexico blocks can be held by operations or commercial production, and the corresponding lease periods extend as long as governmental approved operations continue on the relevant block. This can extend the lease expiration to a date later than 2033.

Ghana

The WCTP and DT Blocks are located within the Tano Basin, offshore Ghana. This basin contains a proven world-class petroleum system as evidenced by our discoveries. In October 2021, Kosmos completed the acquisition of Anadarko WCTP Company ("Anadarko WCTP"), a subsidiary of Occidental Petroleum Corporation, which owned a participating interest in the WCTP Block and DT Block offshore Ghana, including an 18.0% participating interest in the Jubilee Unit Area and an 11.1% participating interest in the TEN Fields. Following closing of the acquisition, Kosmos' interest in the Jubilee Unit Area increased from 24.1% to 42.1%, and Kosmos' interest in the TEN Fields increased from 17.0% to 28.1%. In

November 2021, we received notice from Tullow Oil plc ("Tullow") that they were exercising their pre-emption rights in relation to Kosmos' acquisition of Anadarko WCTP. After execution of definitive transaction documentation and receipt of governmental approvals, Kosmos concluded the pre-emption transaction with Tullow in March 2022. Following completion of the pre-emption process, Kosmos' interest in the Jubilee Unit Area decreased from 42.1% to 38.6% and Kosmos' interest in the TEN Fields decreased from 28.1% to 20.4%. The following is a brief discussion of our discoveries on our license areas offshore Ghana.

Ghana West Cape Three Points Block

Tullow is the operator of the West Cape Three Points Block. Under the WCTP petroleum contract, Kosmos is required to pay to the Government of Ghana a fixed royalty of 5% and a potential sliding-scale royalty ("additional oil entitlement"), which comes into effect and escalates as the nominal project rate of return increases above a certain threshold. These royalties are to be paid in-kind or, at the election of the Government of Ghana, in cash. A corporate tax rate of 35% is applied to profits at a country level. The WCTP petroleum contract has a duration of 30 years from its effective date (July 2004).

In July 2011, at the end of the seven-year Exploration Period, parts of the WCTP Block on which we had not declared a discovery area, were not in a development and production area, or were not in the Jubilee Unit, were relinquished ("WCTP Relinquishment Area"). We maintain rights to the Akasa discovery within the WCTP Block as the WCTP petroleum contract remains in effect after the end of the Exploration Period. We and our WCTP Block partners have certain rights to negotiate a new petroleum contract with respect to certain portions of the WCTP Relinquishment Area. We and our WCTP Block partners, the Ghana Ministry of Energy and GNPC have agreed such WCTP petroleum contract rights to negotiate extend from July 21, 2011 until such time as either a new petroleum contract is negotiated and entered into with us or we decline to match a bona fide third-party offer GNPC may receive for the WCTP Relinquishment Area.

Ghana Deepwater Tano Block

Tullow is the operator of the Deepwater Tano Block. Under the DT petroleum contract, GNPC exercised its option to acquire an additional paying interest of 5% in the commercial discovery with respect to the Jubilee Field development and the TEN Fields development. Kosmos is required to pay to the Government of Ghana a fixed royalty of 5% and a potential additional oil entitlement, which comes into effect and escalates as the nominal project rate of return increases above a certain threshold. These royalties are to be paid in-kind or, at the election of the Government of Ghana, in cash. A corporate tax rate of 35% is applied to profits at a country level. The DT petroleum contract has a duration of 30 years from its effective date (July 2006).

In 2013, at the end of the seven-year Exploration Period, parts of the DT Block on which we had not declared a discovery area, were not in a development and production area, or were not in the Jubilee Unit, were relinquished ("DT Relinquishment Area"). Our existing Wawa discovery within the DT Block was not subject to relinquishment upon expiration of the Exploration Period of the DT petroleum contract, as the DT petroleum contract remains in effect after the end of the Exploration Period while commerciality is being determined. Pursuant to our DT petroleum contract, we and our DT Block partners have certain rights to negotiate a new petroleum contract with respect to certain portions of the DT Relinquishment Area until such time as either a new petroleum contract is negotiated and entered into with us or we decline to match a bona fide third-party offer GNPC may receive for the DT Relinquishment Area.

The Ghanaian Petroleum Exploration and Production Law of 1984 (PNDCL 84) (the "1984 Ghanaian Petroleum Law") and the WCTP and DT petroleum contracts form the basis of our exploration, development and production operations on the WCTP and DT blocks. Pursuant to these petroleum contracts, most significant decisions, including PoDs and annual work programs, for operations other than exploration and appraisal, must be approved by a joint management committee, consisting of representatives of certain block partners and GNPC. Certain decisions require unanimity.

Jubilee Field

The Jubilee Field was discovered by Kosmos in 2007 by the Mahogany-1 well with first oil produced in 2010. The field covers an area within both the WCTP and DT Blocks. To optimize resource recovery in the Jubilee Field, it was unitized and the Jubilee UUOA was agreed to in 2009 which governs each party's respective rights and duties in the Jubilee Unit and named Tullow as the Unit Operator. Although the Jubilee Field is unitized, Kosmos' participating interests in each block outside the boundary of the Jubilee Unit are not impacted by the Jubilee UUOA. Currently, the WCTP petroleum contract has a 54.367% participating interest in the Jubilee Unit and the DT petroleum contract has a 45.633% participating interest in the Jubilee Unit. Our participating interest in the Jubilee Unit is based on these allocations and any event of redetermination in the future would impact Jubilee Unit participating interest.

The Jubilee Field is located approximately 60 kilometers offshore Ghana in water depths of approximately 1,000 to 1,800 meters, which led to the decision to implement an FPSO based development. The FPSO is designed to provide water and natural gas injection to support reservoir pressure, to process and store oil and to export gas through a pipeline to the mainland. The Jubilee Field continues to be developed in a phased approach. The initial phase provided subsea infrastructure capacity for additional production and injection wells to be drilled in future phases of development. The phased development of the Jubilee Field continued during 2023 successfully bringing four production wells and two injection wells online which included three wells (two production wells and one injection well) as part of the successful startup of the Jubilee Southeast project. The Jubilee Southeast project also included the installation of a new subsea production manifold. The development drilling campaign is planned to continue in 2024. One new injection well and one new production well were brought online early in the first quarter of 2024. The partnership expects to bring an additional three wells online in 2024 including two production wells and one injection well before we expect the rig contract to end.

In 2022, the partnership exported approximately 98 million standard cubic feet of natural gas per day (gross) on average from the Jubilee Field to the mainland. In December 2022, an interim gas sales agreement for 19 Bcf (gross) was executed with the Government of Ghana, which allowed for natural gas to be sold at $0.50 per MMBtu. In January 2023, the volume of approximately 19 Bcf of Jubilee gas (in restoration of the amount originally substituted from TEN) had been sold to Ghana under the terms of the TAG GSA at $0.50 per MMBtu. The Jubilee partners reached an interim agreement to sell Jubilee Field gas at a price of $2.95 per MMBtu to the Government of Ghana beyond the 19 Bcf from the Jubilee Field through May 2024, while the partners continue on-going discussions with the Government of Ghana regarding a long-term future gas sales agreement. Our inability to continuously export associated natural gas from the Jubilee Field could eventually impact our oil production and could cause us to re-inject or flare any natural gas we cannot export.

TEN

The TEN Fields are located in the western and central portions of the DT Block, approximately 48 kilometers offshore Ghana in water depths of approximately 1,000 to 1,700 meters. The discoveries have been jointly developed with shared infrastructure and a single FPSO, with first oil produced in 2016. Similar to Jubilee, the TEN Fields have been developed in a phased manner. The TEN PoD was designed to include an expandable subsea system that could provide for multiple phases.

The construction and connection of a gas pipeline between the Jubilee and TEN Fields to transport natural gas to the mainland for processing and sale was completed in 2017. In December 2017, we signed the TAG GSA. The partnership is currently in discussions with the Government of Ghana regarding a future gas sales agreement. During the second quarter of 2023, the operator submitted a draft amended plan of development for TEN, as well as a term sheet for a gas sales agreement covering future gas sales from both Jubilee and TEN Fields, to the Government of Ghana. If the amended plan of development is delayed or not approved, it could lead to a curtailment or delay of investment and development activity in TEN. Our inability to continuously export associated natural gas from the TEN Fields could eventually impact our oil production and could cause us to re-inject or flare any natural gas we cannot export.

U.S. Gulf of Mexico

In the U.S. Gulf of Mexico, Kosmos maintains: (i) a portfolio of producing assets that Kosmos can continue to exploit, (ii) discovered resource opportunities, and (iii) a high-quality inventory of infrastructure-led exploration prospects across the DeSoto Canyon, Green Canyon, Keathley Canyon, Mississippi Canyon and Walker Ridge protraction areas. We expand our inventory through the U.S. Gulf of Mexico Federal lease sales and farm-in transactions.

The following is a brief discussion of our key fields in the U.S. Gulf of Mexico.

Odd Job

The Odd Job Field is producing from three Middle Miocene wells through the Delta House FPS, operated by Murphy. In June 2022, we executed, as operator of the Odd Job Field, a contract for $131.6 million (gross) with Subsea 7 (US) LLC and OneSubsea LLC to fabricate and install a subsea pump in the Odd Job Field. The Odd Job Field subsea pump installation project was approximately 90% complete as of the end of 2023 with an expected online date around the middle of 2024. The project is expected to sustain long-term production from the Odd Job Field.

Tornado

The Tornado Field is producing from three Pliocene wells through the Helix Producer I, a ship-shaped, dynamically-positioned production platform in the deepwater U.S. Gulf of Mexico, which is operated by Talos Energy.

Kodiak

The Kodiak Field is producing from two wells, which are completed in the Middle Miocene sands. These wells are flowing through the Devils Tower Spar platform, which is operated by ENI US Operating Co. Inc. ("ENI"). One of these wells, the Kodiak-3 infill well, was brought online in April 2021. The well experienced production issues and was shut-in. In March 2022, the Company commenced operations to plug back and side-track the original Kodiak-3 infill well. The well was sidetracked, and the Kodiak-3ST well was brought online in September 2022. Well results and initial production were in line with expectations, however well productivity declined through the end of the third quarter of 2022. Workover plans have been developed and are expected to commence around the middle of 2024.

Winterfell

In January 2021, we announced the Winterfell-1 exploration well encountered approximately 26 meters (85 feet) of net oil pay in two intervals. Winterfell was designed to test a sub-salt Upper Miocene prospect located in Green Canyon Block 944. In January 2022, the Winterfell-2 appraisal well in Green Canyon Block 943 was drilled to evaluate the adjacent fault block to the northwest of the original Winterfell discovery and was designed to test two horizons that were oil bearing in the Winterfell-1 well, with an exploration tail into a deeper horizon. The well discovered approximately 40 meters (120 feet) of net oil pay in the first and second horizons with better oil saturation and porosity than pre-drill expectations. The exploration tail discovered an additional oil-bearing horizon in a deeper reservoir which is also prospective in the blocks immediately to the north. During the third quarter of 2022, the Field Development Plan for the Winterfell Field was approved by all partners as a five well tieback to the Heidelberg facility which is operated by Oxy. The development drilling plan for the first phase included the sidetrack and completion of the Winterfell-1 well, completion of the Winterfell-2 well and drilling and completion of the Winterfell-3 well in an adjacent fault block to the southeast of the Winterfell-1 discovery well. The development drilling plan commenced in the third quarter of 2023 with the sidetrack and completion of the Winterfell-1 well in the fourth quarter of 2023. The Winterfell-2 well was completed early in the first quarter of 2024. The Winterfell-3 well is expected to commence drilling later in 2024. In addition, the host facility production handling agreement and oil export agreements have been executed. First production for Phase 1A of the project is targeted for early in the second quarter of 2024.

Tiberius

In July 2023, Kosmos spud the Tiberius infrastructure-led exploration prospect, which is located in block 964 of Keathley Canyon (33% working interest) in the Outer Wilcox play. In October 2023, we announced the well encountered approximately 75 meters (250 feet) of net oil pay in the primary Wilcox target. Initial fluid and core analysis supports the production potential of the wells, with characteristics analogous with similar nearby discoveries in the Wilcox trend. We are now working with partners on development options for the discovery.

Mauritania

In June 2012, we entered into a petroleum contract covering offshore Mauritania Block C8 with the Islamic Republic of Mauritania. Cost recovery oil is apportioned to the contractor from up to 55% (62% for gas) of total production prior to profit oil being split between the Government of Mauritania and the contractor. Profit oil is then apportioned based upon "R-factor" tranches, where the R-factor is cumulative net revenues divided by the cumulative investment. At the election of the Government of Mauritania, the government may receive its share of production in cash or in kind. A corporate tax rate of 27% is applied to profits at the license level. In June 2022, the exploration period of Block C8 offshore Mauritania expired and in October 2022 the partnership and the Government of Mauritania executed a new Petroleum contract covering the BirAllah and Orca discoveries in Block C8. The new Petroleum contract (named BirAllah) provides up to thirty months to submit a development plan covering the BirAllah and/or Orca discoveries with the terms of the new Petroleum contract substantially similar to the former Petroleum contract for Block C8 with additional provisions for enhanced back-in rights for the Government of Mauritania, local content, SMH's capacity building and an environmental fund. Kosmos' participating interest in the new Petroleum contract is 28.0% and full election by SMH of their back-in rights would reduce Kosmos' participating interest to approximately 22.1%.

The C8 and BirAllah blocks are located on the western margin of the Mauritania Salt Basin offshore Mauritania and range in water depths from 100 to 3,000 meters. These blocks are located in a proven petroleum system, with our primary targets being Cretaceous sands in structural and stratigraphic traps.

The C8 and BirAllah blocks cover an aggregate area of approximately 735 thousand acres (gross). We have acquired approximately 580 line-kilometers of 2D seismic data and 3,000 square kilometers of 3D seismic data covering portions of our blocks in Mauritania. Based on these 2D and 3D seismic programs, we have drilled three successful exploration wells and one appraisal well in Block C8 (now Greater Tortue Ahmeyim) and what is now the BirAllah block.

Senegal

The Saint Louis Offshore Profond and Cayar Offshore Profond Blocks are located in the Senegal River Cretaceous petroleum system and range in water depth from 300 to 3,100 meters. The area is an extension of the working petroleum system in the Mauritania Salt Basin. We acquired approximately 3,700 square kilometers of 3D seismic data over these Senegal blocks. We have drilled three successful exploration wells and two appraisal wells.

In June 2018, we entered the final renewal of the exploration period for the Senegal Cayar Offshore Profond and Saint Louis Offshore Profond Blocks. In July 2021, the term of the Cayar Offshore Profound license was extended for up to an additional three years, ending in July 2024. We are currently working with the Government of Senegal on a further extension of the term for the Cayar Offshore Profond license. In the event of commercial success, we have the right to develop and produce oil and/or gas for a period of 25 years from the grant of an exploitation authorization from the government, which may be extended on two separate occasions for a period of 10 years each under certain circumstances. The exploration period of the St. Louis Offshore Profound license expired in July 2021.

The following is a brief discussion of our discoveries to date offshore Mauritania and Senegal.

Greater Tortue Ahmeyim Development

The Greater Tortue Ahmeyim Field, discovered by the Tortue-1 well in May 2015, in Mauritania Block C8 and by the Guembuel-1 well in January 2016, in the Saint-Louis Offshore Profond Block in Senegal covers an area within both the C8 and Saint-Louis Offshore Profond Blocks. Mauritania and Senegal agreed that the Greater Tortue Ahmeyim Field would be unitized for optimal resource recovery in the Inter-State Cooperation Agreement (ICA) signed in February 2018. The GTA UUOA was agreed between the contractor groups of the C8 and Saint-Louis Offshore Profond Blocks and approved by the appropriate Ministers in Mauritania and Senegal in February 2019. BP Mauritania and BP Senegal are co-Unit Operator and allocate responsibilities for the initial development of the Greater Tortue Ahmeyim Field. During the second quarter of 2019, SMH and PETROSEN elected to increase their respective interests in their portion of the Greater Tortue Ahmeyim Unit to the maximum allowed percentages under the respective petroleum contracts. After the elections, our interest in the exploration areas of Block C8 offshore Mauritania and in Saint Louis Offshore Profound offshore Senegal are unchanged, however, our interest in the Greater Tortue Ahmeyim Unit is now 26.8% in Mauritania and 26.7% in Senegal and is subject to redetermination of the participating interests pursuant to the terms of the GTA UUOA. In February 2019, Mauritania and Senegal each issued an exploitation authorization for the Greater Tortue Ahmeyim Unit area covered by the GTA UUOA.

The Greater Tortue Ahmeyim discoveries are significant, play-opening gas discoveries for the outboard Cretaceous petroleum system and are located approximately 120 kilometers offshore Mauritania and Senegal. The Greater Tortue Ahmeyim development straddles Block C8 offshore Mauritania and Saint Louis Offshore Profond Block offshore Senegal.

We have drilled four exploration and appraisal wells within the Greater Tortue Ahmeyim development, Tortue-1, Guembeul-1, Ahmeyim-2 and Greater Tortue Ahmeyim-1 (GTA-1). The wells penetrated multiple, excellent quality gas reservoirs, including the Lower Cenomanian, Upper Cenomanian and underlying Albian. The wells successfully delineated the Ahmeyim and Guembeul gas discoveries and demonstrated reservoir continuity, as well as static pressure communication between the three wells drilled within the Lower Cenomanian reservoir. The discoveries range in water depths from approximately 2,700 meters to 2,800 meters, with total depths drilled ranging from approximately 5,100 meters to 5,250 meters.

The Tortue-1 discovery well, located in Block C8 offshore Mauritania, intersected approximately 117 meters of net hydrocarbon pay. A single gas pool was encountered in the Lower Cenomanian objective, which is comprised of three reservoirs totaling 88 meters in thickness over a gross hydrocarbon interval of 160 meters. A fourth reservoir totaling 19 meters was penetrated within the Upper Cenomanian target over a gross hydrocarbon interval of 150 meters. The exploration well also intersected an additional 10 meters of net hydrocarbon pay in the lower Albian section, which is interpreted to be gas.

The Guembeul-1 discovery well, located in the northern part of the Saint Louis Offshore Profond area in Senegal, is located approximately five kilometers south of the Tortue-1 exploration well in Mauritania. The well encountered 101 meters of net gas pay in two excellent quality reservoirs, including 56 meters in the Lower Cenomanian and 45 meters in the underlying Albian, with no water encountered.

The Ahmeyim-2 appraisal well is located in Block C8 offshore Mauritania, approximately five kilometers northwest, and 200 meters down-dip of the basin-opening Tortue-1 discovery. The well confirmed significant thickening of the gross reservoir sequences down-dip. The Ahmeyim-2 well encountered 78 meters of net gas pay in two excellent quality reservoirs, including 46 meters in the Lower Cenomanian and 32 meters in the underlying Albian.

The Greater Tortue Ahmeyim-1 (GTA-1) appraisal well was drilled on the eastern anticline within the unit development area of Greater Tortue Ahmeyim field. The GTA-1 well encountered approximately 30 meters of net gas pay in high quality Albian reservoir. The well was drilled in approximately 2,500 meters of water, approximately 10 kilometers inboard of the Guembeul-1A and Tortue-1 wells, to a total depth of 4,884 meters.

In 2017, we completed a DST on the Tortue-1 well, demonstrating that the Tortue field is a world-class resource and confirming key development parameters including well deliverability, reservoir connectivity, and fluid composition. The Tortue-1 well flowed at a sustained, equipment-constrained rate of approximately 60 MMcfd during the main extended flow period, with minimal pressure drawdown, providing confidence in well designs that are each capable of producing approximately 200 MMcfd. The DST results confirmed a connected volume per well consistent with the current development scheme, which together with the high well rate is expected to result in a low number of development wells compared to equivalent schemes. Initial analysis of fluid samples collected during the test indicate Tortue gas is well suited for liquefaction given low levels of liquids and minimal impurities.

In December 2018, we and our partners announced that a final investment decision for Phase 1 of the Greater Tortue Ahmeyim project had been agreed. The Greater Tortue Ahmeyim project is designed to produce gas from a deepwater subsea system to a mid-water FPSO, which processes the gas to make it liquefaction ready, and sends the gas through a pipeline to a FLNG facility. The FLNG facility is protected behind a nearshore hub (which serves as a breakwater and LNG terminal) and is located on the Mauritania and Senegal maritime border. The FLNG facility for Phase 1 is designed to produce approximately 2.5 million tons per annum on average. The project will provide LNG for global export, as well as make gas available for domestic use in both Mauritania and Senegal. Following a competitive tender process, BP Gas Marketing (“BPGM”) was selected as the buyer for the LNG offtake for Greater Tortue Ahmeyim Phase 1, and the Tortue Phase 1 SPA was executed in February 2020 with an initial term of 10 years with a seller’s option to extend the term for an additional 10 years. Additionally, to optimize the commercial value of sales for the gas production from Phase 1 of Greater Tortue Ahmeyim, Kosmos has commenced a process with prospective buyers to utilize existing contractual rights under our existing Tortue Phase 1 SPA to potentially sell cargos in order to benefit from the robust forward gas price outlook, while meeting our contractual obligations to BPGM. BPGM has disagreed with our position, and we have agreed with BPGM to pursue international arbitration to interpret the relevant terms of the SPA.

Phase 1 of the project was approximately 90% complete at year-end 2023, with first gas for the project targeted in the third quarter of 2024. The operator has successfully drilled and completed all four wells needed for Phase 1 start up. The FLNG construction was completed in 2023 and the vessel arrived on location offshore Mauritania/Senegal in the first quarter of 2024. Hookup and pre-commissioning work is now underway. Construction work is complete on the hub terminal and handover to operations was completed in August 2023. Significant progress has been made on the installation of the infield flowlines and subsea structures. Work re-commenced in the fourth quarter of 2023 and is expected to be completed at the end of the second quarter of 2024. The FPSO is currently in a shipyard in Tenerife for inspection and repair of fairleads. Completion of this work and transit to the project site is expected early in the second quarter of 2024 ahead of final hookup and commissioning.

Other Mauritania and Senegal Discoveries

BirAllah and Orca Discoveries

The BirAllah discovery (formerly known as Marsouin), located in the BirAllah block offshore Mauritania, is a significant, play-extending gas discovery, building on our successful exploration program in the outboard Cretaceous petroleum system offshore Mauritania. In November 2015, the Marsouin-1 well, located approximately 60 kilometers north of the Ahmeyim discovery, and was drilled to a total depth of 5,150 meters in nearly 2,400 meters of water. Based on analysis of drilling results and logging data, Marsouin-1 encountered at least 70 meters of net gas pay in Upper and Lower Cenomanian intervals comprised of excellent quality reservoir sands.

The Orca-1 well, located in the BirAllah block offshore Mauritania, was drilled in October 2019 and delivered a major gas discovery. The Orca-1 well, which targeted a previously untested Albian play, encountered 36 meters of net gas pay in excellent quality reservoirs. In addition, the well extended the Cenomanian play fairway by confirming 11 meters of net gas pay in a down-structure position relative to the original Marsouin-1 discovery well. The location of the Orca-1 well proved both the structural and stratigraphic components of the trap are working, thereby supporting a significant volume. The Orca-1 well was drilled in approximately 2,510 meters of water to a total measured depth of around 5,266 meters.

In total, we believe that Marsouin-1 and Orca-1 have de-risked significant resource in support of a potential world-scale LNG project from the Cenomanian and Albian plays in the BirAllah area. The BirAllah and Orca discoveries are being analyzed as a potential joint development. In October 2022, the partnership and the Government of Mauritania executed a new Petroleum contract covering the BirAllah and Orca discoveries. The new Petroleum contract provides the partnership up to thirty months to submit a development plan covering the BirAllah and/or Orca discoveries with the terms of the new Petroleum contract substantially similar to the former Petroleum contract for Block C8 with additional provisions for enhanced back-in rights for the Government of Mauritania, local content, SMH’s capacity building and an environmental fund.

Yakaar and Teranga Discoveries

The Teranga discovery is located in the Cayar Offshore Profond block approximately 65 kilometers northwest of Dakar and was our second exploration well offshore Senegal. The Teranga-1 discovery well is located in nearly 1,800 meters of water and was drilled to a total depth of approximately 4,850 meters. The well encountered 31 meters of net gas pay in good quality reservoir in the Lower Cenomanian objective. Well results confirm that a prolific inboard gas fairway extends approximately 200 kilometers south from the Marsouin-1 well in Mauritania through the Greater Tortue Ahmeyim area on the maritime boundary to the Teranga-1 well in Senegal.

The Yakaar discovery is located in the Cayar Offshore Profond block offshore Senegal, approximately 95 kilometers northwest of Dakar in approximately 2,600 meters of water. The Yakaar-1 discovery well was drilled to a total depth of approximately 4,900 meters. The well intersected a gross hydrocarbon column of 120 meters in three pools within the primary Lower Cenomanian objective and encountered 45 meters of net pay. In September 2019, we completed the Yakaar-2 appraisal well, which encountered approximately 30 meters of net gas pay. The Yakaar-2 well was drilled approximately nine kilometers from the Yakaar-1 exploration well and further delineated the southern extension of the field.

The results of the Yakaar-2 well underpin our view that the Yakaar-Teranga resource base is world-scale and has the potential to support an LNG project that provides significant volumes of natural gas to both domestic and export markets. Development of Yakaar-Teranga is being considered in a phased approach with Phase 1 providing domestic gas and data to optimize the development of future phases. It could also support the country’s “Plan Emergent Senegal” launched by the President of Senegal in 2014.

The Yakaar and Teranga discoveries continue to be analyzed as a joint development. During 2023, we continued progressing appraisal studies, maturing concept design, and proposed to partners that the Yakaar and Teranga discoveries in the Cayar Offshore Profond Block be pursued as a commercial joint development. PETROSEN agreed to the proposal, however, BP decided not to participate in the development and exploitation of the Yakaar and Teranga discoveries. In accordance with the provisions of the Contract for Exploration and Production Sharing of Hydrocarbons for the Cayar Offshore Profond Block and the related Joint Operating Agreement (the “JOA”), BP has waived its rights in respect of the Yakaar and Teranga discoveries. As provided in the JOA, Kosmos has assumed BP’s participating interest under the contract and the JOA and has become operator of the Cayar Offshore Profond Block, with customary government approvals having been received effective January 18, 2024. The participating interests in the Cayar Offshore Profond Block are now: Kosmos 90% and PETROSEN 10%, with PETROSEN having the right to increase its participating interest after issuance of an exploitation authorization to up to 35%.

Equatorial Guinea

In March 2018, we entered into petroleum contracts covering Blocks EG-21 and S with the Republic of Equatorial Guinea. Kosmos currently holds an 80% participating interest in Block EG-21 and a 34% participating interest in Block S. The Equatorial Guinean national oil company, GEPetrol, currently has a 20% carried participating interest in each Block during the exploration period. Should a commercial discovery be made, GEPetrol's 20% carried interest in such Block will convert to a 20% participating interest. In December 2022, an extension was granted extending the first exploration sub-period for Block EG-21 to December 2024 and we received formal approval to proceed to the second exploration sub-period for Block S ending in December 2024. In March 2023, we closed a farm-out agreement with Panoro, whereby, Panoro acquired a 6.0% participating interest in Block S offshore Equatorial Guinea. As a result of the farm-out agreement, Kosmos’ participating interest in Block S was reduced to 34.0%.

In June 2018, we closed a farm-in agreement with a subsidiary of Ophir for Block EG-24, offshore Equatorial Guinea, whereby we acquired a 40% non-operated participating interest. In the first quarter of 2019, we acquired Ophir's remaining interest in and operatorship of the block, which resulted in Kosmos owning an 80% participating interest in Block EG-24. GEPetrol currently has a 20% carried interest during the exploration period. In December 2022, we received formal approval to enter the second sub-period of the exploration period ending in December 2024. Should a commercial discovery be made, GEPetrol's 20% carried interest will convert to a 30% participating interest for all development and production operations.

In February 2023, Kosmos and Panoro Energy ASA (“Panoro”) entered into a petroleum contract covering Block EG-01 offshore Equatorial Guinea with the Republic of Equatorial Guinea. Kosmos holds a 24% participating interest in the block and the operator, Panoro, holds a 56% participating interest. GEPetrol currently has a 20% carried participating interest during the exploration period. Should a commercial discovery be made, GEPetrol’s 20% carried interest will convert to a 20% participating interest. Block EG-01 currently comprises approximately 59,400 acres (240 square kilometers), with a first exploration period of three years from the effective date (March 1, 2023).

The EG-01, EG-21, EG-24 and S blocks are located in the southern part of the Gulf of Guinea, in the Republic of Equatorial Guinea, west of the Rio Muni petroleum province with water depths up to 2,300 meters. These blocks are located in a proven petroleum system, with our primary targets being Cretaceous sands in structural and stratigraphic traps. In total, the exploration petroleum contracts cover approximately 7,500 square kilometers and we have over 6,400 square kilometers of 3D seismic over the blocks. The seismic data is being interpreted and high graded prospects for future drilling are being matured.

Ceiba Field and Okume Complex

In Equatorial Guinea, we maintain a 40.4% undivided participating interest in the Ceiba Field and Okume Complex. These offshore assets in the Gulf of Guinea provide cash flow through production with the potential to increase production through exploration opportunities with potential low cost tie-backs to existing infrastructure.

The shared development of the Ceiba Field and Okume Complex consists of six subsea-well clusters that feed production to the Ceiba FPSO which is shared by both fields through a system of risers. The Okume Complex includes six platforms with an export line to move Okume production to the Ceiba FPSO.

In May 2022, Kosmos and its joint venture partners agreed with the Ministry of Mines and Hydrocarbons of Equatorial Guinea to extend the Block G petroleum contract term; harmonizing the expiration of the Ceiba Field and Okume Complex production licenses (from 2029 and 2034 respectively) to 2040. The license extensions support the next phase of investment in the licenses.

The 2023 Ceiba Field and Okume Complex development rig campaign commenced in the fourth quarter of 2023. The campaign initially completed one production well workover. However, as a result of safety issues with the drilling rig, the operator terminated the rig contract in early February 2024. The partnership is seeking to secure an alternative rig and drilling contractor to resume the work, which is planned to include the drilling of in-fill production wells in Block G and the Akeng Deep ILX prospect in Block S.

Asam Discovery

In October 2019, the S-5 exploration well was drilled to a total depth of 4,400 meters in Block S offshore Equatorial Guinea, encountering 39 meters of net oil pay in good-quality Santonian reservoir. The discovery was subsequently named Asam. In July 2020, an appraisal work program was approved by the Government of Equatorial Guinea. The well is located within tieback range of the Ceiba FPSO and the appraisal work program is currently ongoing to establish the scale of the discovered resource and evaluate the optimum development solution. In December 2022, as part of the appraisal work program, the Asam field appraisal report was submitted to the Government of Equatorial Guinea.

Sao Tome and Principe

We are the operator for the petroleum contract covering Block 5, offshore Sao Tome and Principe in the Gulf of Guinea. The block covers an area of approximately 0.5 million acres (gross) in water depths ranging from 2,150 to 3,000 meters.

Our block is adjacent to, and represents a potential extension of, a proven and prolific petroleum system offshore Equatorial Guinea and northern Gabon comprising Cretaceous post-rift source rocks and Late Cretaceous reservoirs.

In August 2017, we completed a 3D seismic survey of approximately 2,500 square kilometers offshore Sao Tome and Principe. Processing has been completed and the 3D seismic data has been integrated into our geological evaluation. We continue to mature an inventory of prospects on the license area in Sao Tome and Principe and will continue to refine and assess the prospectivity. In the second quarter of 2023, we received approval to extend the exploration phase for Block 5 offshore Sao Tome and Principe through May 2024.

Our Reserves

The following table sets forth summary information about our estimated proved reserves as of December 31, 2023. See "Item 8. Financial Statements and Supplementary Data—Supplemental Oil and Gas Data (Unaudited)" for additional information.

Our estimated proved reserves as of December 31, 2023, 2022, and 2021 were associated with our fields in Ghana, Equatorial Guinea, Mauritania, Senegal and the U.S. Gulf of Mexico.

Summary of Oil and Gas Reserves

	2023 Net Proved Reserves(1)			2022 Net Proved Reserves(1)			2021 Net Proved Reserves(1)		
	Oil, Condensate, NGLs(5) (MMBbl)	Natural Gas(3) (Bcf)	Total (MMBoe)	Oil, Condensate, NGLs(5) (MMBbl)	Natural Gas(3) (Bcf)	Total (MMBoe)	Oil, Condensate, NGLs(5) (MMBbl)	Natural Gas(3) (Bcf)	Total (MMBoe)
Reserves Category									
Proved developed									
Ghana(2)	46	79	60	43	40	50	52	56	61
Equatorial Guinea	19	16	22	20	16	23	20	11	22
Mauritania/Senegal	—	—	—	—	—	—	—	—	—
U.S. Gulf of Mexico	15	12	17	21	17	24	28	20	31
Total proved developed	81	106	99	84	73	96	100	87	115
Proved undeveloped									
Ghana(2)	47	56	56	56	9	58	68	12	70
Equatorial Guinea	5	—	5	5	—	5	5	—	5
Mauritania/Senegal	7	628	112	7	618	110	8	590	106
U.S. Gulf of Mexico	6	6	7	6	7	8	4	6	5
Total proved undeveloped(4)	64	690	179	74	634	180	85	608	186
Total Kosmos proved reserves	145	797	278	158	707	276	185	695	301

(1) Totals within the table may not add as a result of rounding.

(2) Our reserves associated with the Jubilee Field are based on the 54.4%/45.6% redetermination split between the WCTP Block and DT Block. Table above reflects the acquisition of additional interests in Ghana in October 2021 and the pre-emption transaction with Tullow in March 2022. See "Item 8. Financial Statements and Supplementary Data—Note 3—Acquisitions and Divestitures" for discussion of pre-emption transaction with Tullow.

(3) These reserves include the estimated quantity of gas to be exported as LNG from the Greater Tortue Ahmeyim Phase 1 project, as a result of the Tortue SPA finalized in February of 2020. We note that the LNG is presented as Plant Products in MBoe in our 2021 reserve report. Our natural gas reserves in Ghana include natural gas forecasted to be sold to the Government of Ghana. If and when a future long-term gas sales agreement is executed with the Government of Ghana, a portion of the remaining gas may be recognized as reserves.

These natural gas reserves also include the estimated quantities of fuel gas required to operate the Jubilee and TEN FPSOs, the Equatorial Guinea facilities and the Greater Tortue Ahmeyim facilities during normal field operations. For Ghana, total proved natural gas reserves include fuel gas associated with the Jubilee and TEN Fields offshore Ghana of approximately 19.9 Bcf, 22.9 Bcf and 30.0 Bcf for 2023, 2022 and 2021, respectively. Our natural gas reserves in Equatorial Guinea are all associated with fuel gas. For Mauritania/Senegal, total proved natural gas reserves include fuel gas of approximately 52.3 Bcf, 51.0 Bcf and 51.0 Bcf in 2023, 2022 and 2021, respectively. For the U.S. Gulf of Mexico, total proved natural gas reserves include fuel gas of approximately 1.1 Bcf in 2023.

(4) Proved undeveloped reserves as of December 31, 2023 expected to be developed beyond five years since initial disclosure are all related to the Greater Tortue Ahmeyim project in Mauritania and Senegal which is a long-term project being developed under a continuous drilling program with long-term LNG sales obligations.

(5) Natural gas liquids proved reserves represent an immaterial amount of our total proved reserves. Therefore, we have aggregated natural gas liquids and crude oil/condensate reserves information.

Changes during the year ended December 31, 2023 at Greater Jubilee include a positive revision of 35.1 MMBoe primarily due to positive field performance, the addition of gas sales recognition and positive drilling results, offset by Jubilee net production of 12.8 MMBoe. There were no changes related to the commodity price effect in Jubilee. These revisions resulted in an overall increase of 22.4 MMBoe. Changes at TEN include a negative revision of 12.6 MMBoe, primarily driven by a change in the partnership's development work scope for the TEN Fields and well performance, net TEN production of 1.3 MMBoe, for an overall decrease in reserves of 13.9 MMBoe. There were no changes related to the commodity price effect in TEN. Changes at Equatorial Guinea included a positive revision of 3.0 MMBoe due to field performance, offset by a negative revision related to the commodity price effect of 0.7 MMBoe and net production of 3.5 MMBoe. The overall net reserves at Equatorial Guinea decreased by 1.1 MMBoe. Changes in Mauritania and Senegal include a small positive revision of 1.3 MMBoe due to optimization of the timing of the Greater Tortue Ahmeyim Phase 1 project. There were no changes related to the commodity price effect on reserves in Mauritania and Senegal. Changes at the U.S. Gulf of Mexico include a negative revision of 2.3 MMBoe primarily driven by the performance of Odd Job and Tornado Fields as well as the negative results from the drilling of a Marmalard well. The U.S. Gulf of Mexico net production for the year ended December 31, 2023 was 5.6 MMBoe for an overall reserves decrease of 7.9 MMBoe. The changes related to the commodity price effect in the U.S. Gulf of Mexico were immaterial.

During the year ended December 31, 2023, we had an overall proved undeveloped reserves decrease of 1.3 MMBoe due to several factors including the addition of sales gas and positive revision of future well forecasts based on improved performance of existing wells in Jubilee (+26.0 MMBoe), positive drilling results in Jubilee (+0.7 MMBoe), offset by a change to the partnership's development work scope and forecasts of planned wells in TEN (-6.4 MMBoe), removal of one of the planned wells from the Okume drilling plan (-0.3 MMBoe), optimization of the timing of the Greater Tortue Ahmeyim Phase 1 project (+1.3 MMBoe), and changes to the recovery of several U.S. Gulf of Mexico fields (-0.3 MMBoe). Conversion of proved undeveloped volumes to proved developed related to drilling during 2023 includes the drilling of five wells in Jubilee (-21.5 MMBoe) and one well in Marmalard (-0.8 MMBoe).

In Greater Jubilee, we converted 21.5 MMBoe of proved undeveloped reserves to proved developed with the drilling of five wells at a cost of approximately $98.0 million as well as approximately $91.3 million in subsea costs. In addition, we spent approximately $40.5 million on wells that are expected to convert in future years. In Mauritania and Senegal, we spent approximately $259.8 million progressing the Greater Tortue Ahmeyim Phase 1 development with first gas for the project targeted in the third quarter of 2024. In the U.S. Gulf of Mexico, we converted 0.8 MMBoe at a cost of approximately $16.5 million with the drilling of one well in the Marmalard Field. In addition, we spent approximately $49.0 million on the Odd Job subsea pump installation and approximately $67.5 million towards the development of the Winterfell Field.

Changes during the year ended December 31, 2022, at Greater Jubilee include a positive revision of 11.7 MMBoe primarily due to positive drilling results and field performance, offset by a negative revision of 7.5 MMBoe resulting from the conclusion of the Tullow pre-emption transaction in March 2022, as well as Jubilee net production of 11.3 MMBoe. These revisions resulted in an overall decrease in reserves of 7.1 MMBoe. Changes at TEN include a negative revision of 5.5 MMBoe, driven primarily by recent well performance. Additional negative revisions of 9.1 MMBoe resulted from the conclusion of the Tullow pre-emption transaction in March 2022, along with net TEN production of 2.0 MMBoe. These revisions resulted in an overall decrease in reserves of 16.7 MMBoe. Changes at Equatorial Guinea included a positive revision of 4.0 MMBoe driven by the Block G petroleum license extension and improved commodity prices. An additional positive revision of 0.9 MMBoe due to Ceiba production performance and topsides optimization was offset by net Equatorial Guinea production of 3.7 MMBoe. These revisions resulted in an overall increase in reserves of 1.2 MMBoe and changes in gas reserves were negligible. Changes at Mauritania/Senegal include a positive revision of 4.7 MMBoe of gas due to field extension resulting from the drilling of production wells, as well as a negative revision of 0.7 MMBoe in condensate based on an updated yield estimate. These revisions resulted in an overall increase in reserves of 4.0 MMBoe. Changes at the U.S. Gulf of Mexico include positive revisions of 3.0 MMBoe associated with the Winterfell discovery and 0.8 MMBoe related to the acquisition of an additional interest in the Kodiak field. These changes were offset by a negative revision of 2.0 MMBoe based on recent water breakthrough in Odd Job and Tornado, and Kodiak production issues. The U.S. Gulf of Mexico net production for the year ended December 31, 2022 was 6.4 MMBoe. These revisions resulted in an overall decrease in reserves of 4.6 MMBoe.

During the year ended December 31, 2022, we had an overall proved undeveloped reserves decrease of 5.6 MMBoe, as a result of several factors, including the impact of the Tullow pre-emption transaction in March 2022 (-7.9 MMBoe), optimization of future drilling in Jubilee (+4.0 MMBoe) and TEN (+2.1 MMBoe), Greater Tortue field extension that resulted from drilling of production wells and a downward condensate adjustment (+4.0 MMBoe), optimizing future development plans in the U.S. Gulf of Mexico (+1.3 MMBoe), purchase of minerals-in-place during 2022 in the Kodiak field (+0.2 MMBoe) and the Winterfell discovery (+3.0 MMBoe). Drilling activity impact on proved undeveloped volume change includes the drilling of three wells in Jubilee (-4.6 MMBoe), one well in TEN (-5.8 MMBoe), and one well in Kodiak (-2.0 MMBoe). We note that the changes in the proved undeveloped reserves in Equatorial Guinea were negligible.

In Greater Jubilee, we converted 4.6 MMBoe of proved undeveloped reserves to proved developed with the drilling of three wells at a cost of approximately $75.1 million. In TEN, we converted 5.8 MMBoe of proved undeveloped reserves to proved developed with the drilling of one well at a cost of approximately $13.6 million. In the U.S. Gulf of Mexico, we converted 2.0 MMBoe of proved undeveloped reserves to proved developed with the drilling of one well in Kodiak at a cost of $13.6 million.

Changes during the year ended December 31, 2021, at Greater Jubilee include a positive revision of 49.1 MMBoe, of which 39.9 MMBoe were acquired on October 13, 2021 in the acquisition of additional interests in Ghana. The other 9.2 MMBoe of additions were primarily due to field performance, positive drilling results, and optimization of future development plans. The additions were partially offset by net Greater Jubilee production of 7.4 MMBoe which includes production related to our acquisition of additional interests in Ghana commencing October 13, 2021, the acquisition date. Changes at TEN include a positive revision of 18.2 MMBoe, of which 16.2 MMBoe were acquired in the acquisition of additional interests in Ghana. The other 2.0 MMBoe of additions were primarily due to an increase in estimated associated gas sales. The additions were partially offset by net TEN production of 2.2 MMBoe. Changes at Equatorial Guinea included an increase of 3.7 MMBoe related to Okume Complex performance and drilling results, which was offset by 3.6 MMBoe of net production. Changes at the U.S. Gulf of Mexico included an increase of 4.4 MMBoe related to strong performance of certain fields, offset by net U.S. Gulf of Mexico production of 7.2 MMBoe.

During the year ended December 31, 2021, we had an overall proved undeveloped reserves increase of 136.3 MMBoe as a result of several factors, including the acquisition of additional interests in Ghana (+22.7 MMBoe for Greater Jubilee and +6.6 MMBoe for TEN), optimization of future drilling in Greater Jubilee (+17.8 MMBoe), adding a future development well and optimizing future development plans in the U.S. Gulf of Mexico and Equatorial Guinea (+6.8 MMBoe), and the economic status of the Greater Tortue Ahmeyim project due to project progress and improved oil price (+106.5 MMBoe). Drilling activity impact on proved undeveloped volume change includes the drilling of two wells in Greater Jubilee (-17.1 MMBoe), one well in TEN (-3.6 MMBoe), two wells in Equatorial Guinea (-1.2 MMBoe), and one well in Tornado in the U.S. Gulf of Mexico (-2.1 MMBoe).

In Greater Jubilee, we converted 17.1 MMBoe of proved undeveloped reserves to proved developed with the drilling of two wells at a cost of $25.2 million. In TEN, we converted 3.6 MMBoe of proved undeveloped reserves with the drilling of one well at a cost of $8.9 million. In Equatorial Guinea we spent $35.6 million to drill two wells and to replace certain subsea infrastructure, which converted 1.8 MMBoe of proved undeveloped reserves to proved developed. In the U.S. Gulf of Mexico, we converted 2.1 MMBoe of proved undeveloped reserves to proved developed with the drilling of one well in Tornado at a cost of $19.0 million.

Estimated proved reserves

Unless otherwise specifically identified in this report, the summary data with respect to our estimated net proved reserves for the years ended December 31, 2023, 2022 and 2021 has been prepared by RSC, our independent reserve engineering firm for such years, in accordance with the rules and regulations of the SEC applicable to companies involved in oil and natural gas producing activities. These rules require SEC reporting companies to prepare their reserve estimates using reserve definitions and pricing based on 12-month historical unweighted first-day-of-the-month average prices, rather than year-end prices. For a definition of proved reserves under the SEC rules, see the “Glossary and Selected Abbreviations.” For more information regarding our independent reserve engineers, please see “—Independent petroleum engineers” below.

Our estimated proved reserves and related future net revenues, PV-10 and Standardized Measure were determined in accordance with SEC rules for proved reserves.

Future net revenues represent projected revenues from the sale of proved reserves net of production and development costs (including operating expenses and production taxes). Such calculations at December 31, 2023 are based on costs in effect at December 31, 2023 and the 12-month unweighted arithmetic average of the first-day-of-the-month price for the year ended December 31, 2023, adjusted for anticipated market premium, without giving effect to derivative transactions, and are held constant throughout the life of the assets. There can be no assurance that the proved reserves will be produced within the periods indicated or prices and costs will remain constant.

Independent petroleum engineers

Ryder Scott Company, L.P.

RSC, our independent reserve engineers for the years ended December 31, 2023, 2022 and 2021, was established in 1937. For over 80 years, RSC has provided services to the worldwide petroleum industry that include the issuance of reserves reports and audits, appraisal of oil and gas properties including fair market value determination, reservoir simulation studies, enhanced recovery services, expert witness testimony, and management advisory services. RSC professionals subscribe to a code of professional conduct and RSC is a Registered Engineering Firm in the State of Texas.

For the years ended December 31, 2023, 2022 and 2021, we engaged RSC to prepare independent estimates of the extent and value of the proved reserves of certain of our oil and gas properties. These reports were prepared at our request to estimate our reserves and related future net revenues and PV-10 for the periods indicated therein. Our estimated reserves at December 31, 2023, 2022 and 2021 and related future net revenues and PV-10 at December 31, 2023, 2022 and 2021 are taken from reports prepared by RSC, in accordance with petroleum engineering and evaluation principles which RSC believes are commonly used in the industry and definitions and current regulations established by the SEC. The December 31, 2023 reserve report was completed on January 15, 2024, and a copy is included as an exhibit to this report.

In connection with the preparation of the December 31, 2023, 2022 and 2021 reserves report, RSC prepared its own estimates of our proved reserves. In the process of the reserves evaluation, RSC did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices or any agreements relating to current and future operations of the fields and sales of production. However, if in the course of the examination something came to the attention of RSC which brought into question the validity or sufficiency of any such information or data, RSC did not rely on such information or data until it had satisfactorily resolved its questions relating thereto or had independently verified such information or data. RSC independently prepared reserves estimates to conform to the guidelines of the SEC, including the criteria of “reasonable certainty,” as it pertains to expectations about the recoverability of reserves in future years, under existing economic and operating conditions, consistent with the definition in Rule 4-10(a)(2) of Regulation S-X. RSC issued a report on our proved reserves at December 31, 2023, based upon its evaluation. RSC’s primary economic assumptions in estimates included an ability to sell hydrocarbons at their respective adjusted benchmark prices and certain levels of future capital expenditures. The assumptions, data, methods and precedents were appropriate for the purpose served by these reports, and RSC used all methods and procedures as it considered necessary under the circumstances to prepare the report.

Technology used to establish proved reserves

Under the SEC rules, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term “reasonable certainty” implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have proved effective by actual comparison of production from projects in the same reservoir interval, an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

In order to establish reasonable certainty with respect to our estimated proved reserves, RSC employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, production and injection data, electrical logs, radioactivity logs, acoustic logs, whole core analysis, sidewall core analysis, downhole pressure and temperature measurements, reservoir fluid samples, geochemical information, geologic maps, seismic data, well test and interference pressure and rate data. Reserves attributable to undeveloped locations were estimated using performance from analogous wells with similar geologic depositional environments, rock quality, appraisal plans and development plans to assess the estimated ultimate recoverable reserves as a function of the original oil in place. These qualitative measures are benchmarked and validated against sound petroleum reservoir engineering principles and equations to estimate the ultimate recoverable reserves volume. These techniques include, but are not limited to, nodal analysis, material balance, and numerical flow simulation.

Internal controls over reserves estimation process

In our Reservoir Engineering team, we maintain an internal staff of petroleum engineering and geoscience professionals with significant experience that contribute to our internal reserve and resource estimates. This team works closely with our independent petroleum engineers to ensure the integrity, accuracy and timeliness of data furnished in their reserve and resource estimation process. Our Reservoir Engineering team is responsible for overseeing the preparation of our reserves estimates and has over 100 combined years of industry experience among them with positions of increasing responsibility in engineering and evaluations. Each member of our team holds a minimum of a Bachelor of Science degree in petroleum engineering or geology. The person primarily responsible for our Reservoir Engineering team is Mr. Douglas Trumbauer. Mr. Trumbauer is a Licensed Professional Engineer in the State of Texas (No. 78735) and has over 38 years of practical experience in petroleum engineering. He graduated from Pennsylvania State University in 1985 with a Bachelor of Science degree in Petroleum and Natural Gas Engineering. Mr. Trumbauer worked for DeGolyer and MacNaughton for 20 years prior to joining Kosmos Energy, and we believe he is proficient in applying industry standard practices to engineering and geoscience evaluations as well as understanding and applying SEC and other industry reserves definitions and guidelines.

The RSC technical person primarily responsible for preparing the estimates set forth in the RSC reserves report incorporated herein is Mr. Tosin Famurewa. Mr. Famurewa has been practicing consulting petroleum engineering at RSC since 2006. Mr. Famurewa is a Licensed Professional Engineer in the State of Texas (No. 100569) and has over 20 years of practical experience in petroleum engineering. He graduated from University of California at Berkeley in 2000 with Bachelor of Science Degrees in Chemical Engineering and Material Science Engineering, and he received a Master of Science degree in Petroleum Engineering from University of Southern California in 2007. Mr. Famurewa meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

The Audit Committee provides oversight on the processes utilized in the development of our internal reserve and resource estimates on an annual basis. In addition, our Reservoir Engineering team meets with representatives of our independent reserve engineers to review our assets and discuss methods and assumptions used in preparation of the reserve and resource estimates. Finally, our senior management reviews reserve and resource estimates on an annual basis.

Gross and Net Undeveloped and Developed Acreage

The following table sets forth certain information regarding the developed and undeveloped portions of our license and lease areas as of December 31, 2023 for the countries in which we currently operate.

	Developed Area (Acres)		Undeveloped Area (Acres)		Total Area (Acres)		Current Phase Exploration Range	
	Gross	Net(1)	Gross	Net(1)	Gross	Net(1)		
	(In thousands)							
Ghana(2)	164	43	33	9	197	52	—	(2)
Equatorial Guinea	65	26	1,857	1,311	1,922	1,337	2024 and 2026	
Mauritania	—	—	735	204	735	204	2025	
Sao Tome and Principe	—	—	527	310	527	310	2024	
Senegal	—	—	917	743	917	743	2024	
U.S. Gulf of Mexico(3)	110	30	142	76	252	106	through 2033	(3)
Total	339	99	4,211	2,653	4,550	2,752		

(1) Net acreage based on Kosmos' participating interests, including any options or back-in rights which have been exercised (Jubilee, TEN, and Greater Tortue Ahmeyim fields), but before the exercise of any options or back-in rights that exist, but have not been exercised. Our net acreage in Ghana may be affected by any redetermination of interests

in the Jubilee Unit and our net acreage in Mauritania and Senegal may be affected by any redetermination of interests in the Greater Tortue Ahmeyim Unit.

(2) The Exploration Period of the WCTP petroleum contract and DT petroleum contract has expired. The undeveloped area reflected in the table above represents acreage within our discovery areas that were not subject to relinquishment on the expiry of the Exploration Period.

(3) Our developed U.S. Gulf of Mexico blocks are held by production/operations, and the lease periods extend as long as production/governmental approved operations continue on the relevant block. For undeveloped areas, the licenses are immaterial with various exploration phases, with all ending by 2033.

Productive Wells

Productive wells consist of producing wells and wells capable of production, including wells awaiting connections. For wells that produce both oil and gas, the well is classified as an oil well. The following table sets forth the number of productive oil and gas wells in which we held an interest at December 31, 2023:

	Productive Oil Wells		Productive Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Ghana(2)	60	19.89	—	—	60	19.89
Equatorial Guinea	80	32.32	—	—	80	32.32
U.S. Gulf of Mexico(2)	22	6.13	—	—	22	6.13
Total(1)	162	58.34	—	—	162	58.34

(1) Of the 162 productive wells, 51 (gross) or 17 (net) have multiple completions within the wellbore.

(2) Table above reflects our additional interests acquired in Ghana and U.S. Gulf of Mexico. See "Item 8. Financial Statements and Supplementary Data—Note 3—Acquisitions and Divestitures" for discussion of potential pre-emption impact.

Drilling activity

The results of oil and natural gas wells drilled and completed for each of the last three years were as follows:

	Exploratory and Appraisal Wells(1)						Development Wells(1)							
	Productive(2)		Dry(3)		Total		Productive(2)		Dry(3)		Total		Total	Total
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Year Ended December 31, 2023														
Ghana	—	—	—	—	—	—	7	2.70	—	—	7	2.70	7	2.70
Mauritania/Senegal	—	—	—	—	—	—	1	0.27	—	—	1	0.27	1	0.27
U.S. Gulf of Mexico	1	0.25	—	—	1	0.25	1	0.11	—	—	1	0.11	2	0.36
Total	1.00	0.25	—	—	1.00	0.25	9.00	3.08	—	—	9.00	3.08	10.00	3.33
Year Ended December 31, 2022														
Ghana(4)(5)	—	—	2	0.41	2	0.41	5	1.57	—	—	5	1.57	7	1.98
Mauritania/Senegal	—	—	—	—	—	—	3	0.80	—	—	3	0.80	3	0.80
Total	—	—	2	0.41	2	0.41	8	2.37	—	—	8	2.37	10	2.78
Year Ended December 31, 2021														
Ghana(4)	—	—	—	—	—	—	4	1.54	—	—	4	1.54	4	1.54
Equatorial Guinea	—	—	—	—	—	—	2	0.80	—	—	2	0.80	2	0.80
U.S. Gulf of Mexico	—	—	1	0.38	1	0.38	1	0.29	—	—	1	0.29	2	0.67
Total	—	—	1	0.38	1	0.38	7	2.63	—	—	7	2.63	8	3.01

(1) As of December 31, 2023, 8 exploratory and appraisal wells have been excluded from the table until a determination is made if the wells have found proved reserves. Also excluded from the table are 10 development wells awaiting completion. These wells are shown as “Wells Suspended or Waiting on Completion” in the table below.

(2) A productive well is an exploratory or development well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas producing well. Productive wells are included in the table in the year they were determined to be productive, as opposed to the year the well was drilled.

(3) A dry well is an exploratory or development well that is not a productive well. Dry wells are included in the table in the year they were determined not to be a productive well, as opposed to the year the well was drilled.

(4) Table above reflects the acquisition of additional interests in Ghana in October 2021 and the pre-emption transaction with Tullow in March 2022. See “Item 8. Financial Statements and Supplementary Data—Note 3—Acquisitions and Divestitures” for discussion of pre-emption transaction with Tullow.

(5) Includes the NT-10 and NT-11 wells which are considered step out wells from an accounting perspective but were drilled as part of the TEN Plan of Development.

The following table shows the number of wells that are in the process of being drilled or are in active completion stages, and the number of wells suspended or waiting on completion as of December 31, 2023.

	Actively Drilling or Completing				Wells Suspended or Waiting on Completion			
	Exploration		Development		Exploration		Development	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Ghana								
Jubilee Unit	—	—	1	0.39	—	—	4	1.54
TEN	—	—	—	—	—	—	5	1.02
Equatorial Guinea								
Block S	—	—	—	—	1	0.40	—	—
Okume	—	—	—	—	—	—	1	0.40
U.S. Gulf of Mexico								
Winterfell	1	0.25	—	—	—	—	—	—
Tiberius	—	—	—	—	1	0.33	—	—
Mauritania / Senegal								
Mauritania BirAllah Block	—	—	—	—	2	0.56	—	—
Greater Tortue Ahmeyim Unit	—	—	—	—	1	0.27	—	—
Senegal Cayar Profond	—	—	—	—	3	0.90	—	—
Total	1	0.25	1	0.39	8	2.46	10	2.96

Domestic Supply Requirements

Many of our petroleum contracts or, in some cases, the applicable law governing such agreements, grant a right to the respective host country to purchase certain amounts of oil/gas produced pursuant to such agreements at international market prices for domestic consumption. In addition, in connection with the approval of the Jubilee Phase 1 PoD, the Jubilee Field partners agreed to provide the first 200 Bcf of natural gas produced from the Jubilee Field Phase 1 development to GNPC at no cost. As of January 1, 2023, the Jubilee partners had fulfilled this commitment. The Jubilee partners reached an interim agreement to sell Jubilee Field gas at a price of $2.95 per MMBtu to the Government of Ghana through May 2024 while the partners continue on-going discussions with the Government of Ghana regarding a long-term future gas sales agreement.

Sales and Marketing

As provided under the Jubilee UUOA and the WCTP and DT petroleum contracts, we are entitled to lift and sell our share of the Jubilee and TEN production as are the other Jubilee Unit and TEN partners. Over the years, we have entered into agreements with multiple oil marketing agents to market our share of the Jubilee and TEN Fields oil, and we approve the terms of each sale proposed by such agent. In Equatorial Guinea, as provided under the petroleum contract for Block G, we are entitled to lift and sell our share of the Ceiba Field and Okume Complex production as are the other Block G partners. We currently have crude oil marketing sales agreements with oil marketers to market our share of the Jubilee, TEN and Ceiba Field and Okume Complex oil, and we approve the terms of each sale proposed by such agents.

In the U.S. Gulf of Mexico, we sell crude oil to purchasers typically through monthly contracts, with the sale taking place at multiple points offshore, depending on the particular property. Natural gas is sold to purchasers monthly through long-term contracts, with the sale taking place either offshore or at an onshore gas processing plant after the removal of NGLs. We actively market our crude oil and natural gas to purchasers, and sales prices for purchased oil and natural gas volumes are negotiated with purchasers and are based on certain published indices. Since most of the oil and natural gas contracts are generally month-to-month and at varying physical locations, there are very few dedications of production to any one purchaser. We sell the NGLs entrained in the natural gas that we produce. The arrangements to sell these products first require natural gas to be processed at an onshore gas processing plant. Once the liquids are removed and fractionated (separated into the individual hydrocarbon chains for sale), the products are sold by the processing plant. The residue gas left over is sold to natural gas purchasers as natural gas sales (referenced above). The contracts for NGL sales are with the processing plant. The prices received for the NGLs are either tied to indices or are based on what the processing plant can receive from a third-party purchaser. The gas processing and subsequent sales of NGLs are subject to contracts with longer terms and dedications of life of lease production from the Company's leases offshore.

There are a variety of factors which affect the market for oil, including the proximity and capacity of transportation facilities, demand for oil both within the local market and beyond, the marketing of competitive fuels and the effects of government regulations on oil production and sales. Our revenue can be materially affected by current economic conditions and the price of oil. However, based on the current demand for crude oil and the fact that alternative purchasers are available, we believe that the loss of one of our marketing agents and/or any of the purchasers identified by our marketing agent would not have a long-term material adverse effect on our financial position or results of operations. The continued economic disruption resulting from Russia's war in Ukraine, potential instability in the Middle East, a potential regional or global recession, inflationary pressures and other varying macroeconomic conditions could further materially impact the Company's business in future periods. Any potential disruption will depend on the duration and intensity of these events, which are highly uncertain and cannot be predicted at this time.

In February 2020, we, along with the co-venturers in the Greater Tortue Ahmeyim Field signed the Tortue Phase 1 SPA with BPGM to sell LNG free on board (FOB) from the Greater Tortue Ahmeyim Field located offshore Mauritania and Senegal. The annual contract quantity under the Tortue Phase 1 SPA is 127,951,000 MMBtu (the "ACQ") which is equivalent to approximately 2.45 million tonnes per annum, subject to limited downward adjustment by the sellers. The sales price for LNG under the Tortue Phase 1 SPA is set as a percentage of a crude oil price benchmark for the ACQ volumes (the "ACQ Sales Price"). The Tortue Phase 1 SPA has an initial term of up to twenty years that commences on the "Commercial Operations Date", which occurs after completion of certain LNG project facilities' performance tests. Additionally, to optimize the commercial value of sales for the gas production from the Phase 1 of Greater Tortue Ahmeyim, Kosmos has commenced a process with prospective buyers to utilize existing contractual rights under our existing Tortue Phase 1 SPA to potentially sell cargos in order to benefit from the robust forward gas price outlook, while meeting our contractual obligations to BPGM. BPGM has disagreed with our position, and we have agreed with BPGM to pursue international arbitration to interpret the relevant terms of the SPA.

Competition

The oil and gas industry is competitive. We encounter strong competition from other independent operators and from major oil companies in acquiring licenses and leases. 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 oil and natural gas assets, or to evaluate, bid for and purchase a greater number of licenses and leases 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.

Historically, we have also been affected by competition for drilling rigs and the availability of related equipment. Higher commodity prices generally increase the demand for drilling rigs, supplies, services, equipment and crews. Shortages of, or increasing costs for, experienced drilling crews and equipment and services may restrict our ability to drill wells and conduct our operations.

The oil and gas industry as a whole has experienced continued volatility. Globally, the impact of Russia's war in Ukraine, potential instability in the Middle East, a potential recession, inflationary pressures and other varying macroeconomic conditions has impacted supply and demand for oil and gas, which also resulted in significant variations in oil and gas prices. Dated Brent crude, the benchmark for our international oil sales, ranged from approximately $71 to $98 per barrel during 2023. HLS crude, the benchmark for our U.S. Gulf of Mexico oil sales, which generally trades at a discount to Dated Brent, ranged from approximately $68 to $95 during 2023. Excluding the impact of hedges, our realized oil price for 2023 was $81.35 per barrel.

Title to Property

We believe that we have satisfactory title to our oil and natural gas assets in accordance with standards generally accepted in the international oil and gas industry. Our licenses and leases are subject to customary royalty and other interests, liens under operating agreements and other burdens, restrictions and encumbrances customary in the oil and gas industry that we believe do not materially interfere with the use of, or affect the carrying value of, our interests.

Environmental Matters

General

We are subject to various stringent and complex international, foreign, federal, state and local environmental, health and safety laws and regulations governing matters including the emission and discharge of pollutants into the ground, air or water; the generation, storage, handling, use and transportation of regulated materials; and the health and safety of our employees. These laws and regulations may, among other things:

- require the acquisition, renewal and maintenance of various permits before operations commence or for operations to continue;
- enjoin operations or facilities to comply with applicable regulations and permits;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling, production and transportation activities;
- limit, cap, tax or otherwise restrict emissions of GHG and other air pollutants or otherwise seek to address or minimize the effects of climate change, as well as require disclosure of GHG emissions and other climate change-related information;
- limit or prohibit drilling activities in certain locations lying within protected or otherwise sensitive areas; and
- require measures to mitigate or remediate pollution, including pollution resulting from our block partners' or our contractors' operations.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. Compliance with these laws can be costly; the regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. We are committed to continued compliance with all environmental laws and regulations applicable to our operations in all countries in which we do business. We have established policies, operating procedures and training programs designed to limit the environmental impact of our operations and to identify and comply with existing and new laws and regulations, however the cost of compliance with existing or more stringent laws and regulations in the future could have a material adverse effect on our financial condition and results of operations.

Moreover, public interest in the protection of the environment continues to increase. Offshore drilling in some areas has been opposed by environmental groups and, in other areas, has been restricted. Our operations could be adversely affected to the extent laws or regulations are enacted or other governmental action is taken that prohibits or restricts offshore drilling or imposes environmental requirements that increase costs to the oil and gas industry in general, such as more stringent or costly waste handling, disposal or cleanup requirements or financial responsibility and assurance requirements.

Per common industry practice, under agreements governing the terms of use of the drilling rigs contracted by us or our block or lease partners, the drilling rig contractors typically indemnify us and our block partners in respect of pollution and environmental damage originating above the surface of the water and from such drilling rig contractor's property, including their drilling rig and other related equipment. Furthermore, pursuant to the terms of the operating agreements for our blocks and leases, except in certain circumstances, each block or lease partner is responsible for its share of liabilities in proportion to its participating interest incurred as a result of pollution and environmental damage, containment and clean-up activities, loss or damage to any well, loss of oil or natural gas resulting from a blowout, crater, fire, or uncontrolled well, loss of stored oil and natural gas, as well as for plugging or bringing under control any well. We maintain insurance coverage typical of the industry in the areas we operate in; these include property damage insurance, loss of production insurance, wreck removal insurance, control of well insurance, general liability including pollution liability to cover pollution from wells and other operations. We also participate in an insurance coverage program for the FPSOs we own. We believe our insurance is carried in amounts typical for the industry relative to our size and operations and in accordance with our contractual and regulatory obligations.

International (Non-operated)

Tullow, BP, and Trident, our partners and the operators of (i) the Jubilee Unit and the TEN Fields offshore Ghana, (ii) various fields offshore Mauritania and Senegal, and (iii) the Ceiba Field and Okume Complex offshore Equatorial Guinea, respectively, maintain Oil Spill Response Plans (“OSRP”) covering the joint operations. The OSRPs include access to Oil Spill Response Limited’s (“OSRL”) oil spill response services comprising technical expertise and assistance, including access to response equipment and dispersant spraying systems. The equipment includes capping stacks, debris removal, subsea dispersant and auxiliary equipment. The equipment meets industry accepted standards and can be deployed by air cargo and other conventional means to suit multiple application scenarios. Under the OSRPs, emergency response teams may be activated to respond to oil spill incidents.

In addition, Kosmos develops an emergency response plan and subscribes to a response organization to prepare and demonstrate our readiness to respond to a subsea well control incident in the event we are the operator.

U.S. Gulf of Mexico (Operated and Non-operated)

After the major well control incident and oil release in the U.S. Gulf of Mexico in 2010, the U.S. Department of Interior updated regulations which govern the type, amount and capabilities of response equipment that needs to be available to operators to respond to similar incidents. These regulations also dictate the type and frequency of training that operating personnel need to receive and demonstrate proficiency in. Kosmos also has an OSRP which is approved by the Bureau of Safety and Environmental Enforcement (“BSEE”). This OSRP would be activated if needed in the event of an oil spill or containment event in the U.S. Gulf of Mexico where Kosmos is the operator. Kosmos joined several cooperatives that were established to meet the requirements of the new regulations. For capping and containment, Kosmos joined the HWCG, LLC consortium whose capabilities include; (i) one dual ram capping stack rated to 15,000 psi and one valve capping stack rated to 20,000 psi, (ii) intervention equipment to cap and contain a well with the mechanical and structural integrity to be shut in at depths up to 10,000 feet, and (iii) the ability to capture and process 130,000 barrels of fluid per day and 220 MMcf of gas per day. Kosmos is also a member of the Clean Gulf Associate (“CGA”) Oil Spill Cooperative, which provides oil spill response capabilities to meet regulatory requirements. Equipment and services include a High Volume Open Sea Skimming System (“HOSS”), dedicated oil spill response vessels strategically positioned along the U.S. gulf coast, dispersants and dispersant delivery systems, various types of spill response booms and mobile wildlife rehabilitation equipment. Due to federal regulations, all of the HWCG and CGA equipment is dedicated to U.S. operations and cannot be utilized outside the country. In addition, Kosmos is also a member of the Marine Spill Response Corporation (“MSRC”) which also provides various oil spill response services for coastal and inland environments in the U.S. Gulf of Mexico.

Cybersecurity

At Kosmos Energy, cybersecurity risk management is an integral part of our overall Information Technology Disaster Recovery and Security Incident Response Plan. Our cybersecurity risk management program is designed to align with our business strategy based on the size of our company and the level of complexity of our information technology systems and industry best practices. The framework for handling cybersecurity threats and incidents including threats and incidents associated with the use of applications developed and services provided by third-party service providers and coordination across different departments of our company includes assessing the severity of a cybersecurity threat associated with a third-party service provider, various cybersecurity countermeasures and mitigation strategies and informing management and the Audit Committee to our board of directors of material cybersecurity threats and incidents. Our information technology team is responsible for assessing our cybersecurity risk management program and we currently do not engage third parties for such design of our cybersecurity risk management program. In addition, our information technology team provides cybersecurity training to all employees and contractors annually.

The Audit Committee to our board of directors has overall oversight responsibility for our risk management, and is charged with oversight of our cybersecurity risk management program. The Audit Committee is responsible for ensuring that management has processes in place designed to identify and evaluate cybersecurity risks to which the company is exposed and implement processes and programs to manage cybersecurity risks and mitigate cybersecurity incidents. The Audit Committee also reports material cybersecurity risks to our full board of directors. Management is responsible for identifying and assessing material cybersecurity risks on an ongoing basis, establishing processes to ensure that such potential cybersecurity risk exposures are monitored, putting in place appropriate mitigation measures and maintaining cybersecurity programs. Our cybersecurity programs are under the direction of our Chief Information Officer (CIO) who receives reports from our information technology team and monitors the prevention, detection, mitigation, and remediation of cybersecurity incidents. Our CIO and dedicated personnel are certified and experienced information systems security professionals and information security managers with many years of experience. Management, including the CIO, and our information technology team, regularly update the Audit Committee on the Company's cybersecurity programs, material cybersecurity risks and mitigation strategies and provide cybersecurity reports quarterly that cover, among other topics, results of third-party testing and assessments of the Company's cybersecurity programs, developments in cybersecurity and updates to the Company's cybersecurity programs and mitigation strategies.

In 2023, we did not identify any cybersecurity threats that have materially affected or are reasonably likely to materially affect our business strategy, results of operations, or financial condition. However, despite our efforts, we cannot eliminate all risks from cybersecurity threats, or provide assurances that we have not experienced an undetected cybersecurity incident. For more information about these risks, please see "Risk Factors" in this annual report on Form 10-K.

Human Capital Resources

Health and Safety

The health and safety of our employees and those that work with us is a priority for Kosmos. Employees and contractors are expected to take all necessary and reasonable actions to ensure safe operations by following safe work practices, complying with relevant policies and regulations, and completing all applicable training. To support our dedication to health, safety and the environment, we have a comprehensive Health, Safety, Environment and Security ("HSES") management system that applies to all Kosmos employees and contractors known as "The Standard." In addition to adoption of The Standard, Kosmos fosters a strong safety culture through online and in person training, regular emergency response drills, and impactful safety discussions.

Culture, Engagement and Development

Kosmos aims to be a world-class company known for delivering results and being a workplace of choice. We pride ourselves on our ability to provide employees with careers that are professionally challenging, personally rewarding, and focused on delivering value. We aim to provide a stimulating and rewarding work environment through an inclusive culture that promotes entrepreneurial thinking, facilitates teamwork, and embraces ethical behavior.

Kosmos is committed to investing in the development of our employees. We support development through a blend of learning approaches including in-person and virtual training opportunities, on-the-job training, conferences, cross team projects and experiences and our leadership development program. Each year, all employees also have an opportunity to provide feedback on the employee experience and Kosmos culture through our annual employee opinion survey. Based on employee scores and feedback, Kosmos was named in the 2023 Top 100 Places to Work by the Dallas Morning News, as well as the Houston Chronicle. The feedback received through this annual survey is used to support continuous improvement and enhance the overall employee experience. In 2023, Kosmos had a retention rate of 95%.

Diversity and Inclusion

Kosmos focuses on recruiting, retaining, and developing a diverse and inclusive workforce that embraces our values and culture. We seek to promote diversity in our workforce both because it is the right thing to do and because it gives us access to the widest range of talents. Through social and educational events that address the different backgrounds and identities of employees, Kosmos helps foster a spirit of inclusion across the company. We promote and celebrate the array of diverse perspectives and experiences of Kosmos employees and applicants, whether in terms of race, ethnicity, sex, gender, sexual orientation, gender expression, religion, national origin, disability, or experiences.

We seek to employ qualified individuals from the countries in which we operate and are proud of our record of recruitment and retention of local staff. This year we maintained 100% local employees across all our host country offices.

As of December 31, 2023, we had 243 employees with 200 being based in the United States and 43 residing in our foreign offices. Our workforce was approximately 37% gender diverse and approximately 21% minority.

Employee Well-being

Kosmos offers employees a robust range of benefits, including health plans, equity opportunities, savings plans, short- and long-term incentives. All domestic employees are awarded equity in the company as part of the total reward package, aligning employee reward with shareholder interest. We also offer a strong Employee Assistance Program (EAP), which offers free and confidential assessments, counseling, and follow-up services to employees with personal and/or work-related mental health problems.

These benefits are intended to both promote the long-term emotional, physical, and financial health and well-being of our employees and increase employee engagement and retention. Additionally, we believe that these benefits help facilitate a strong work-life balance and a culture that prioritizes overall employee wellness.

Corporate Information

In December 2018, Kosmos Energy Ltd. changed our jurisdiction of incorporation from Bermuda to the State of Delaware, USA. We maintain a registered office in Delaware at Corporation Trust Center, 1209 Orange Street, Wilmington, Delaware 19801. Our executive offices are maintained at 8176 Park Lane, Suite 500, Dallas, Texas 75231, and its telephone number is +1 (214) 445 9600.

Available Information

Kosmos is listed on the NYSE and LSE and our common stock is traded under the symbol KOS. We file or furnish annual, quarterly and current reports, proxy statements and other information with the SEC as well as the London Stock Exchange's Regulatory News Service (“LSE RNS”). The SEC maintains a website at http://www.sec.gov that contains documents we file electronically with the SEC. The LSE RNS maintains a website at http://www.londonstockexchange.com that contains documents we file electronically with the LSE RNS.

The Company also maintains an internet website under the name *www.kosmosenergy.com*. The information on our website is not incorporated by reference into this annual report on Form 10-K and should not be considered a part of this annual report on Form 10-K. Our website is included as an inactive technical reference only. We make available, free of charge, on our website, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after such reports are electronically filed with, or furnished to, the SEC.

Item 1A. Risk Factors

You should consider and read carefully all of the risks and uncertainties described below, together with all of the other information contained in this report, including the consolidated financial statements and the related notes included in "Item 8. Financial Statements and Supplementary Data." If any of the following risks actually occurs, our business, business prospects, financial condition, results of operations or cash flows could be materially adversely affected. The risks below are not the only ones we face. Additional risks not currently known to us or that we currently deem immaterial may also adversely affect us.

Summary Risk Factors

Our business is subject to a number of risks, including risks that may prevent us from achieving our business objectives or may adversely affect our business, financial condition, results of operations, cash flows, and prospects. These risks are discussed more fully below and include, but are not limited to, risks related to:

Our Oil and Natural Gas Operations

- We have limited proved reserves;
- We face substantial uncertainties in estimating the characteristics of our discoveries and our prospects;
- Drilling wells is speculative and may not result in any discoveries;
- Development wells may not result in commercially productive quantities of oil and gas reserves;
- Our identified drilling and infrastructure locations are scheduled out over time, making them susceptible to uncertainties;
- We are contractually obligated to drill wells and declare any discoveries in order to retain exploration and production rights;
- Inability of third parties who contract with us to meet their obligations may adversely affect our financial results;
- The unit partners' respective interests in the Jubilee Unit and Greater Tortue Ahmeyim Unit are subject to redetermination;
- We are not the operator on all of our license areas and facilities and do not hold all of the working interests in certain of our license areas;
- Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate;
- The present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves;
- We may not be able to commercialize our interests in any natural gas produced from our license areas;
- Our inability to access appropriate equipment and infrastructure in a timely manner may hinder our access to oil and natural gas markets or delay our oil and natural gas production;
- We are subject to numerous risks inherent to the exploration and production of oil and natural gas;
- We are subject to drilling and other operational and environmental risks and hazards;
- Our operations may be materially adversely affected by weather-related events, including, but not limited to, tropical storms and hurricanes, and the physical effects of climate change;
- The development schedule of oil and natural gas projects is subject to delays and cost overruns;
- Our offshore and deepwater operations involve special risks that could adversely affect our results of operations;
- We had, and continue to have, disagreements with certain host governments and contractual counterparties regarding certain of our rights and responsibilities and may have future disagreements with our host governments and/or contractual counterparties;
- The geographic locations of our licenses in Africa and the U.S. Gulf of Mexico subject us to a risk of loss of revenue or curtailment of production from factors specifically affecting those areas;

Our Business and Financial Condition

- A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition and results of operations;
- Our business plan requires substantial additional capital;
- We may be required to take write-downs of the carrying values of our oil and natural gas assets due to decreases in the estimated future net cash flows from our operations, which may occur as a result of decreases in oil and natural gas prices, poor field performance, increased expenditures or changes in the timing or amount of investment, among other

things, and such decreases could result in reduced availability under our corporate revolver and commercial debt facility;
- We face various risks associated with increased activism against, or change in public sentiment for, oil and gas exploration, development, and production activities and ESG considerations including climate change and the transition to a lower carbon economy;
- Outbreaks of disease may adversely affect our business operations and financial condition;
- Deterioration in the credit or equity markets could adversely affect us;
- We may incur substantial losses and become subject to liability claims as a result of future oil and natural gas operations, for which we may not have adequate insurance coverage;
- Slower global economic growth rates may materially adversely impact our operating results and financial position;
- Increased costs and availability of capital could adversely affect our business;
- Our derivative activities could result in financial losses or could reduce our income;
- Our commercial debt facility, revolving credit facility and indentures governing our Senior Notes contain certain covenants that may inhibit our ability to make certain investments, incur additional indebtedness and engage in certain other transactions;
- Provisions of our Senior Notes could discourage an acquisition of us by a third-party;
- Our level of indebtedness may increase and thereby reduce our financial flexibility;
- We are a holding company and our ability to make payments on our outstanding indebtedness is dependent upon the receipt of funds from our subsidiaries;
- We may be subject to risks in connection with acquisitions and the integration of acquisitions may be difficult;
- If we fail to realize the anticipated benefits of acquisitions, our results of operations may be adversely affected;
- A cyber incident, including a breach of digital security, could result in information theft, data corruption, operational disruption, and/or financial loss;
- Our ability to utilize net operating loss carryforwards may be subject to certain limitations;

Regulation

- Our business, operations and financial condition may be directly and indirectly adversely affected by political, economic, and environmental circumstances;
- More comprehensive and stringent regulation in the U.S. Gulf of Mexico has materially increased costs and delays in offshore oil and natural gas exploration and production operations;
- The oil and gas industry is intensely competitive and many of our competitors possess and employ substantially greater resources than us;
- Participants in the oil and gas industry are subject to numerous laws, regulations, and other legislative instruments that can affect the cost, manner or feasibility of doing business;
- We are subject to numerous health, safety and environmental laws and regulations which may result in material liabilities and costs;
- We may be exposed to assertions concerning or liabilities under anti-corruption laws;
- Federal regulatory law could have an adverse effect on our ability to use derivative instruments;

General Matters

- We are dependent on certain members of our management and technical team;
- We operate in a litigious environment;
- We face various risks associated with global populism;
- Our share price may be volatile, and purchasers of our common stock could incur substantial losses; and
- Holders of our common stock will be diluted if additional shares are issued.

Risks Relating to our Oil and Natural Gas Operations

We have limited proved reserves and areas that we decide to drill may not yield oil and natural gas in commercial quantities or quality, or at all.

We have limited proved reserves. A portion of our oil and natural gas assets consists of discoveries without approved PoDs and with limited well penetrations, as well as identified yet unproven prospects based on available seismic and geological information that indicates the potential presence of hydrocarbons. However, the areas we decide to drill may not yield oil or natural gas in commercial quantities or quality, or at all. Many of our current discoveries and all of our prospects are in various stages of evaluation that will require substantial additional analysis and interpretation. Even when properly used and interpreted, 2D and 3D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. Accordingly, we do not know if any of our discoveries or prospects will contain oil or natural gas in sufficient quantities or quality to recover drilling and completion costs or to be economically viable. Even if oil or natural gas is found on our discoveries or prospects in commercial quantities, construction costs of gathering lines, subsea infrastructure, other production facilities and floating production systems and transportation costs may prevent such discoveries or prospects from being economically viable, and approval of PoDs by various regulatory authorities, a necessary step in order to develop a commercial discovery, may not be forthcoming. Additionally, the analogies drawn by us using available data from other wells, more fully explored discoveries or producing fields may not prove valid with respect to our drilling prospects. We may terminate our drilling program for a discovery or prospect if data, information, studies and previous reports indicate that the possible development of a discovery or prospect is not commercially viable and, therefore, does not merit further investment. If a significant number of our discoveries or prospects do not prove to be successful, our business, financial condition and results of operations will be materially adversely affected.

The deepwater offshore Mauritania and Senegal, an area in which we currently focus a substantial amount of our development efforts, has only recently been considered economically viable for hydrocarbon production due to the costs and difficulties involved in drilling and development at such depths and the relatively recent discovery of commercial quantities of hydrocarbons in the region. Likewise, our deepwater offshore Sao Tome and Principe license has not yet proved to be an economically viable production area. We have limited proved reserves, and we may not be successful in developing additional commercially viable production from our other discoveries and prospects.

We face substantial uncertainties in estimating the characteristics of our discoveries and our prospects.

We report numerical and other measures of the characteristics of our discoveries and prospects. These measures may be incorrect, as the accuracy of these measures is a function of available data, geological interpretation and judgment. To date, a limited number of our prospects have been drilled. Any analogies drawn by us from other wells, discoveries or producing fields may not prove to be accurate indicators of the success of developing proved reserves from our discoveries and prospects. Furthermore, we have no way of evaluating the accuracy of the data from analog wells or prospects produced by other parties which we may use.

It is possible that few or none of our wells to be drilled will find accumulations of hydrocarbons in commercial quality or quantity. Any significant variance between actual results and our assumptions could materially affect the quantities of hydrocarbons attributable to any particular prospect.

Drilling wells is speculative, often involving significant costs that may be more than we estimate, and may not result in any discoveries or additions to our future production or reserves. Any material inaccuracies in drilling costs, estimates or underlying assumptions will materially affect our business.

Exploring for and developing hydrocarbon reserves involves a high degree of technical, operational and financial risk, which precludes definitive statements as to the time required and costs involved in reaching certain objectives. The budgeted costs of planning, drilling, completing and operating wells are often exceeded and can increase significantly when drilling costs rise due to rising inflationary pressure, a tightening in the supply of various types of oilfield equipment and related services or unanticipated geologic conditions or operational challenges.

Before a well is spud, we incur significant geological and geophysical (seismic) costs, which are incurred whether or not a well eventually produces commercial quantities of hydrocarbons or is drilled at all. Drilling may be unsuccessful for many reasons, including geologic conditions, weather, cost overruns, equipment shortages and mechanical difficulties or force majeure events. Exploratory wells bear a much greater risk of failure than development wells. In the past we have experienced unsuccessful drilling efforts, having drilled dry holes. Furthermore, the successful drilling of a well does not necessarily result in the commercially viable development of a field or be indicative of the potential for the development of a commercially viable field. A variety of factors, including geologic and market-related, can cause a field to become uneconomic or only marginally economic. A lack of drilling opportunities or projects that cease production may cause us to incur significant costs associated with an idle rig and/or related services, particularly if we cannot contract out rig slots to other parties. Many of our prospects that may be developed require significant additional exploration, appraisal and development, regulatory approval and commitments of resources prior to commercial development. In addition, a successful discovery would require significant capital expenditure in order to appraise, develop and produce oil and natural gas, even if we deemed such discovery to be commercially viable. See "—Our business plan requires substantial additional capital, which we may be unable to raise on acceptable terms or at all in the future, which may in turn limit our ability to develop our exploration, appraisal, development and production activities." In the international areas in which we operate, we face higher above-ground risks necessitating higher expected returns, the requirement for increased capital expenditures due to a general lack of infrastructure and underdeveloped oil and gas industries, and increased transportation expenses due to geographic remoteness, which either require a single well to be exceptionally productive, or the existence of multiple successful wells, to allow for the development of a commercially viable field. See "—Our business, operations and financial condition may be directly and indirectly adversely affected by political, economic, and environmental circumstances, and changes in laws and regulations, in the countries and regions in which we operate." Furthermore, if our actual drilling and development costs are significantly more than our estimated costs, we may not be able to continue our business operations as proposed and could be forced to modify our plan of operation.

Development drilling may not result in commercially productive quantities of oil and gas reserves.

Our exploration success has provided us with major development and appraisal projects on which we are moving forward, and any future exploration discoveries will also require significant development efforts to bring to production. We must successfully execute our development projects, including development drilling, in order to generate future production and cash flow. However, development drilling is not always successful and the profitability of development projects may change over time.

For example, in new development projects available data may not allow us to completely know the extent of the reservoir or choose the best locations for drilling development wells. A development well we drill may be a dry hole or result in noncommercial quantities of hydrocarbons. All costs of development drilling and other development activities are capitalized, even if the activities do not result in commercially productive quantities of hydrocarbon reserves. This puts a property at higher risk for future impairment if commodity prices significantly decrease, operating or development costs significantly increase or reservoir performance is below expectations.

Our identified drilling and infrastructure locations are scheduled out over time, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling or infrastructure installation or modification.

Our management team has identified and scheduled drilling locations and possible infrastructure locations on our license and lease areas over a multi-year period. Our ability to drill and develop these locations depends on a number of factors, including the availability of equipment and capital, approval by block or lease partners and national and state regulators, seasonal conditions, oil prices, assessment of risks, costs and drilling results. For example, a shutdown of the U.S. federal government could delay the regulatory review and approval process associated with drilling or developmental activities within our license areas in the U.S. Gulf of Mexico. The final determination on whether to drill or develop any of these locations will be dependent upon the factors described elsewhere in this report as well as, to some degree, the results of our drilling and production activities with respect to our established wells and drilling locations. Because of these uncertainties, we do not know if the drilling locations we have identified will be drilled or infrastructure installed or modified within our expected timeframe or at all or if we will be able to economically produce hydrocarbons from these or any other potential drilling locations. As such, our actual drilling and development activities may be materially different from our current expectations, which could adversely affect our results of operations and financial condition.

Under the terms of certain of our petroleum contracts, we are contractually obligated to drill wells and declare any discoveries in order to retain exploration and production rights. In the competitive market for our license areas, failure to drill these wells or declare any discoveries may result in substantial license renewal costs or loss of our interests in the undeveloped parts of our license areas, which may include certain of our prospects or undeveloped discoveries.

In order to protect our exploration and production rights in our license areas, we may be required to meet various drilling and declaration requirements. In general, unless we make and declare discoveries within certain time periods specified in certain of our petroleum contracts and licenses, our interests in the undeveloped parts of our license areas may lapse. Should the prospects yield discoveries, we cannot assure you that we will not face delays in the appraisal and development of these prospects or otherwise have to relinquish these prospects. The costs to maintain petroleum contracts over such areas may fluctuate and may increase significantly since the original term, and we may not be able to renew or extend such petroleum contracts on commercially reasonable terms or at all. Our actual drilling activities may therefore materially differ from our current expectations, which could adversely affect our business.

Under certain petroleum contracts, we have work commitments to perform exploration and other related activities. Failure to do so may result in our loss of the licenses. As of December 31, 2023, we have unfulfilled drilling obligations for three development wells and one exploration well in Equatorial Guinea. In certain other petroleum contracts, we are in the initial exploration phases, some of which have certain obligations that have yet to be fulfilled. Over the course of the next several years, we may choose to enter into the next phase of those petroleum contracts which will likely include firm obligations to drill wells. Failure to execute our obligations may result in our loss of the licenses.

The exploration period of some of our petroleum contracts has expired or may expire in the near future. For each of our petroleum contracts, we cannot assure you that any renewals or extensions will be granted or whether any new agreements will be available on commercially reasonable terms, or, in some cases, at all. For additional detail regarding the status of our operations with respect to our various petroleum contracts, please see “Item 1. Business—Operations by Geographic Area.”

The inability of one or more third parties who contract with us to meet their obligations to us may adversely affect our financial results.

We may be liable for certain costs if third parties who contract with us or with the operators of our license and lease areas are unable to meet their commitments under such agreements. We are currently exposed to credit risk through joint interest receivables from our block and/or unit partners. If any of our partners in the blocks or unit in which we hold interests are unable to fund their share of the exploration, development and decommissioning expenses, we may be liable for such costs. In the past, certain of our partners have not paid their share of block costs in the time frame required by the relevant agreements for these blocks. This has resulted in such party being in default, which in return requires Kosmos and its non-defaulting block partners to pay their proportionate share of the defaulting party’s costs during the default period. Should a default not be cured, Kosmos could be required to pay its share of the defaulting party’s costs going forward.

In addition, we and the operators of our license and lease areas contract with third parties to conduct drilling and related services on our development projects and exploration prospects. Such third parties may not perform the services they provide us on schedule or within budget. Furthermore, the drilling equipment, facilities and infrastructure owned and operated by such third parties is highly complex and subject to malfunction and breakdown. Any malfunctions or breakdowns may be outside our control and result in delays, which could be substantial. Any delays in our drilling campaign caused by equipment, facility or equipment malfunction or breakdown could materially increase our costs of drilling and cause an adverse effect on our business, financial position and results of operations.

Our principal exposure to credit risk will be through receivables resulting from the sale of our oil and natural gas as well as our commodity derivatives contracts. The inability or failure of our significant customers or counterparties to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. In addition, our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. Joint interest receivables arise from our block partners. The inability or failure of third parties we contract with to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. We are unable to predict sudden changes in creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited and we could incur significant financial losses.

The unit partners’ respective interests in the Jubilee Unit and Greater Tortue Ahmeyim Unit are subject to redetermination and our interests in each such unit may decrease as a result.

The interests in and development of the Jubilee Field are governed by the terms of the Jubilee UUOA. The parties to the Jubilee UUOA, the collective interest holders in each of the WCTP and DT Blocks, initially agreed that interests in the Jubilee Unit will be shared equally, with each block deemed to contribute 50% of the area of such unit. The respective interests in the Jubilee Unit were therefore initially determined by the respective interests in such contributed block interests. Pursuant to the terms of the Jubilee UUOA, the percentage of such contributed interests is subject to a process of redetermination once sufficient development work has been completed in the unit. The initial redetermination process was completed on October 14, 2011. As a result of the initial redetermination process, the tract participation was determined to be 54.4% for the WCTP Block and 45.6% for the DT Block. Consequently, our Unit Interest (participating interest in the Jubilee Unit) was increased from

23.5% to 24.1% upon completion of the initial redetermination process. Following the acquisition of Anadarko WCTP Company, which owned a participating interest in the WCTP Block and DT Block, our Unit Interest (participating interest in the Jubilee Unit) increased from 24.1% to 42.1%. Following the completion of the pre-emption by Tullow in March of 2022, Kosmos' interest in the Jubilee Unit Area decreased from 42.1% to 38.6%. An additional redetermination could occur sometime if requested by a party that holds greater than a 10% interest in the Jubilee Unit. We cannot assure you that any redetermination pursuant to the terms of the Jubilee UUOA will not negatively affect our interests in the Jubilee Unit or that such redetermination will be satisfactorily resolved.

The interests in and development of the Greater Tortue Ahmeyim Field are governed by the terms of the GTA UUOA. The parties to the GTA UUOA, the collective interest holders in each of the Mauritania Block C8 and Senegal Saint Louis Offshore Profond blocks, initially agreed that interests in the Greater Tortue Ahmeyim Unit will be shared equally, with each block deemed to contribute 50% of the area of such unit. The respective interests in the Greater Tortue Ahmeyim Unit were therefore initially determined by the respective interests in such contributed block interests. Pursuant to the terms of the GTA UUOA, the percentage of such contributed interests is subject to a process of redetermination once sufficient development work has been completed in the unit. We cannot assure you that any redetermination pursuant to the terms of the GTA UUOA will not negatively affect our interests in the Greater Tortue Ahmeyim Unit or that such redetermination will be satisfactorily resolved.

We are not, and may not be in the future, the operator on all of our license areas and facilities and do not, and may not in the future, hold all of the working interests in certain of our license areas. Therefore, we have reduced control over the timing of exploration or development efforts, associated costs, and the rate of production of any non-operated and to an extent, any non-wholly-owned, assets.

As we carry out our exploration and development programs, we have arrangements with respect to existing license areas and may have agreements with respect to future license areas that result in a greater proportion of our license areas being operated by others. Currently, we are not the operator of the Jubilee Unit, the TEN Fields, the Ceiba Field and Okume Complex, the Greater Tortue Ahmeyim Unit or certain producing fields in the U.S. Gulf of Mexico and do not hold operatorship in certain other offshore blocks. As a result, we may have limited ability to exercise influence over the operations of the discoveries or prospects operated by our block or unit partners, or which are not wholly-owned by us, as the case may be. Dependence on block or unit partners could prevent us from realizing our target returns for those discoveries or prospects. Further, because we do not have majority ownership in all of our properties, we may not be able to control the timing, or the scope, of exploration or development activities or the amount of capital expenditures and, therefore, may not be able to carry out one of our key business strategies of minimizing the cycle time between discovery and initial production. The success and timing of exploration and development activities will depend on a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- if the activity is operated by one of our block partners, the operator's expertise and financial resources;
- approval of other block partners in drilling wells;
- the scheduling, pre-design, planning, design and approvals of activities and processes;
- selection of technology;
- the available capacity of processing facilities and related pipelines; and
- the rate of production of reserves, if any.

This limited ability to exercise control over the operations on our license areas may cause a material adverse effect on our financial condition and results of operations.

Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is technically complex. It requires interpretations of available technical data and many assumptions, including those relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this report. See “Item 1. Business—Our Reserves” for information about our estimated oil and natural gas reserves and the present value of our net revenues at a 10% discount rate (“PV-10”) and Standardized Measure of discounted future net revenues (as defined herein) as of December 31, 2023.

In order to prepare our estimates, we must project production rates and the timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this report. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

The present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves.

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with the SEC requirements, we have based the estimated discounted future net revenues from our proved reserves on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months, adjusted for an anticipated market premium, without giving effect to derivative transactions. Actual future net revenues from our oil and natural gas assets will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual cost of development and production expenditures;
- derivative transactions;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas assets will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general. Actual future prices and costs may differ materially from those used in the present value estimates included in this report. Oil prices have recently experienced significant volatility. See “Item 1. Business—Our Reserves.”

We may not be able to commercialize our interests in any natural gas produced from our license areas.

The development of the market for natural gas in certain of our international license areas is still in its early stages. Currently the infrastructure to transport and process natural gas on commercial terms is limited and the expenses associated with constructing such infrastructure ourselves may not be commercially viable given local prices currently paid for natural gas. Accordingly, there may be limited or no value derived from any natural gas produced from some of our international license areas.

In Ghana, we currently produce associated gas from the Jubilee and TEN Fields. A gas pipeline from the Jubilee Field has been constructed to transport such natural gas for processing and sale. We granted the Government of Ghana the first 200 Bcf of natural gas exported from the Jubilee Field to shore at zero cost. As of January 1, 2023, the Jubilee partners had fulfilled this commitment. During 2023, the Jubilee partners reached an interim agreement to sell Jubilee Field gas to the Government of Ghana through May 2024 while the partners continue on-going discussions with the Government of Ghana regarding a long-term future gas sales agreement. If the interim gas sales agreement is not extended or a long-term gas sales agreement in Ghana is not approved, we may not be able to commercialize our natural gas resources in Ghana. Our inability to continuously export associated natural gas from the Jubilee and TEN Fields could eventually impact our oil production and could cause us to re-inject or flare any natural gas we cannot export.

In Mauritania and Senegal, we plan to export the majority of our gas resource to the LNG market. However, that plan is contingent on making additional final investment decisions on our gas discoveries and constructing the necessary infrastructure to produce, liquefy and transport the gas to the market. Additionally, such plans are contingent upon receipt of required partner and government approvals.

Our inability to access appropriate equipment and infrastructure in a timely manner may hinder our access to oil and natural gas markets or delay our oil and natural gas production.

Our ability to market our oil and natural gas production will depend substantially on the availability and capacity of processing facilities, oil and LNG tankers and other infrastructure, including FPSOs, owned and operated by third parties. Our failure to obtain such facilities on acceptable terms could materially harm our business. We also rely on continuing access to drilling rigs and construction vessels suitable for the environment in which we operate. The delivery of drilling rigs or construction vessels may be delayed or cancelled, and we may not be able to gain continued access to suitable rigs or vessels in the future. We may be required to shut in oil and natural gas wells because of the absence of a market or because access to processing facilities may be limited or unavailable. If that were to occur, then we would be unable to realize revenue from those wells until arrangements were made to deliver the production to market, which could cause a material adverse effect on our financial condition and results of operations. In addition, the shutting in of wells can lead to mechanical problems upon bringing the production back online, potentially resulting in decreased production and increased remediation costs.

Additionally, the future exploitation and sale of associated and non-associated natural gas and liquids and LNG will be subject to timely commercial processing and marketing of these products, which depends on the contracting, financing, building and operating of infrastructure by third parties. For example, we transport and process natural gas from the Jubilee and TEN Fields to mainland Ghana through a pipeline and processing facilities that are controlled by the Government of Ghana. We cannot provide any assurance about uptime and availability of the pipeline and processing facilities. In addition, during 2023, the Jubilee partners reached an interim agreement to sell Jubilee Field gas to the Government of Ghana through May 2024 while the partners continue on-going discussions with the Government of Ghana regarding a long-term future gas sales agreement. If the interim gas sales agreement is not extended or a long-term gas sales agreement in Ghana is not approved, our ability to continuously extract and process natural gas may be harmed and we may be required to re-inject or flare such natural gas in order to maintain crude oil production and or reduce our overall crude oil production, which may adversely impact our results of operations, financial condition and prospects.

We are subject to numerous risks inherent to the exploration and production of oil and natural gas.

Oil and natural gas exploration and production activities involve many risks that a combination of experience, knowledge and interpretation may not be able to overcome. Our future will depend on the success of our exploration and production activities and on the development of infrastructure that will allow us to take advantage of our discoveries. Additionally, many of our license areas are located in deepwater, which generally increases the capital and operating costs, chances of delay, planning time, technical challenges and risks associated with oil and natural gas exploration and production activities. See "— Our offshore and deepwater operations involve special risks that could adversely affect our results of operation." As a result, our oil and natural gas exploration and production activities are subject to numerous risks, including the risk that drilling will not result in commercially viable oil and natural gas production. Our decisions to purchase, explore or develop discoveries, prospects or licenses will depend in part on the evaluation of seismic data through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations.

Furthermore, the marketability of expected oil and natural gas production from our discoveries and prospects will also be affected by numerous factors. These factors include, but are not limited to, market fluctuations of prices (such as recent significant variations in oil and natural gas prices), proximity, capacity and availability of drilling rigs and related equipment, qualified personnel and support vessels, processing facilities, transportation vehicles and pipelines, equipment availability, access to markets and government regulations (including, without limitation, regulations relating to prices, taxes, royalties, allowable production, domestic supply requirements, importing and exporting of oil and natural gas, the ability to flare or vent natural gas, health and safety matters, environmental protection and climate change). The effect of these factors, individually or jointly, may result in us not receiving an adequate return on invested capital.

In the event that our currently undeveloped discoveries and prospects are developed and become operational, they may not produce oil and natural gas in commercial quantities or at the costs anticipated, and our projects may cease production, in part or entirely, in certain circumstances. Discoveries may become uneconomic as a result of an increase in operating costs to produce oil and natural gas, among other factors. Our actual operating costs and rates of production may differ materially from our current estimates. Moreover, it is possible that other developments, such as increasingly strict environmental, climate change, and health and safety laws, regulations and executive orders and enforcement policies thereunder and claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities, delays, an inability to complete the development of our discoveries or the abandonment of such discoveries, which could cause a material adverse effect on our financial condition and results of operations.

We are subject to drilling and other operational and environmental risks and hazards.

The oil and natural gas business involves a variety of risks, including, but not limited to:

- fires, blowouts, spills, cratering and explosions;
- mechanical and equipment problems, including unforeseen engineering complications;
- uncontrolled flows or leaks of oil, well fluids, natural gas, brine, toxic gas or other pollutants or hazardous materials;
- gas flaring operations;
- marine hazards with respect to offshore operations;
- formations with abnormal pressures;
- pollution, environmental risks, and geological problems; and
- weather conditions and natural or man-made disasters.

These risks are particularly acute in deepwater drilling, exploration, and development. Any of these events could result in loss of human life, significant damage to property, environmental or natural resource damage, impairment, delay or cessation of our operations, lower production rates, adverse publicity, substantial losses and civil or criminal liability. We expect to maintain insurance against some, but not all, of these risks and losses. The occurrence of any of these events, whether or not covered by insurance, could have a material adverse effect on our financial position and results of operations.

Our operations may be materially adversely affected by weather-related events, including, but not limited to, tropical storms and hurricanes, and the physical effects of climate change.

Tropical storms, hurricanes and the threat of tropical storms and hurricanes often result in the shutdown of operations, particularly in the U.S. Gulf of Mexico, as well as operations within the path and the projected path of the tropical storms or hurricanes. In addition, the physical impacts of climate change in the areas in which our assets are located or in which we otherwise operate, including any corresponding increases to the severity and frequency of storms, floods and other weather events, could adversely impact our operations or disrupt transportation or other process-related services provided by our third-party contractors. Weather events have caused significant disruption to the operations of offshore and coastal facilities in the U.S. Gulf of Mexico region. In the future, during a shutdown period, we may be unable to access well sites and our services may be shut down. Additionally, tropical storms or hurricanes may cause evacuation of personnel and damage to our platforms and other equipment, which may result in suspension of our operations. The shutdowns, related evacuations and damage can create unpredictability in activity and utilization rates, as well as delays and cost overruns, which could have a material adverse effect on our business, financial condition and results of operations.

The development schedule of oil and natural gas projects, including the availability and cost of drilling rigs, equipment, supplies, personnel and oilfield services, is subject to delays and cost overruns.

Historically, some oil and natural gas development projects have experienced delays and capital cost increases and overruns due to, among other factors, the unavailability or high cost of drilling rigs and other essential equipment, supplies, personnel and oilfield services, mechanical and technical issues, as well as weather-related delays. The cost to develop our projects has not been fixed and remains dependent upon a number of factors, including the completion of detailed cost estimates and final engineering, contracting and procurement costs. Our construction and operation schedules may not proceed as planned and may experience delays or cost overruns. Any delays may increase the costs of the projects, requiring additional capital, and such capital may not be available in a timely and cost-effective fashion.

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

Offshore operations are subject to a variety of special operating risks specific to the marine environment, such as capsizing, sinking, collisions and damage or loss to pipeline, subsea or other facilities or from weather conditions. 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.

Deepwater exploration generally involves greater operational and financial risks than exploration in shallower waters. Deepwater drilling generally requires 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 of which we are currently unaware. If we participate in the development of new subsea infrastructure and use floating production systems to transport oil from producing wells, these operations 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. For example, we have previously experienced mechanical issues at certain of our offshore production facilities, such as the turret bearing issue on the Jubilee FPSO. The equipment downtime caused by these mechanical issues negatively impacted oil production.

Furthermore, deepwater operations generally, and operations in Africa, in particular, lack the physical and oilfield service infrastructure present in other regions. As a result, a significant amount of time may elapse between a deepwater discovery and the marketing of the associated oil and natural gas, increasing both the financial and operational risks involved with these operations. Because of the lack and high cost of this infrastructure, further discoveries we may make in Africa may never be economically producible.

In addition, in the event of a well control incident, containment and, potentially, cleanup 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 cleanup. As a result, a well control incident could result in substantial liabilities, and have a significant negative impact on our earnings, cash flows, liquidity, financial position, and stock price.

We had, and continue to have, disagreements with certain host governments and contractual counterparties regarding certain of our rights and responsibilities and may have future disagreements with our host governments and/or contractual counterparties.

There can be no assurance that future disagreements will not arise with any host government, national oil companies, and/or contractual counterparties that may have a material adverse effect on our exploration, development or production activities, our ability to operate, our rights under our licenses and local laws or our rights to monetize our interests, but if such disagreements do arise we intend to vigorously dispute them if necessary.

As an example, multiple discovered fields and a significant portion of our proved reserves are located offshore Ghana. The WCTP petroleum contract, the DT petroleum contract and the Jubilee UUOA cover the two blocks and the Jubilee and TEN Fields that form the basis of our current operations in Ghana. Pursuant to these petroleum contracts, most significant decisions, including our plans for development and annual work programs, must be approved by GNPC, the Petroleum Commission and/or Ghana’s Ministry of Energy. We have previously had disagreements with the Ministry of Energy, GNPC, and the Ghana Revenue Authority (the “GRA”) regarding certain of our rights and responsibilities under these petroleum contracts, the 1984 Ghanaian Petroleum Law and the Internal Revenue Act, 2000 (Act 592) (the “Ghanaian Tax Law”). For example, these included disagreements over sharing information with prospective purchasers of our interests, pledging our interests to finance our development activities, potential liabilities arising from discharges of small quantities of drilling fluids into Ghanaian territorial waters, the failure to approve the proposed sale of our Ghanaian assets, assertions that could be read to give rise to taxes or other payments payable under the Ghanaian Tax Law, failure to approve PoDs relating to certain discoveries offshore Ghana and the relinquishment of certain exploration areas on our licensed blocks offshore Ghana. The resolution of certain of these disagreements required us to pay agreed settlement costs to GNPC and/or the Government of Ghana. In Ghana, as part of its normal course audit process the GRA has asserted that we have underpaid certain tax and other contractual fiscal obligations. We believe that these claims are without merit and we intend to vigorously dispute them if necessary, but there can be no assurance regarding the resolution of these or future disagreements.

Additionally, to optimize the commercial value of sales for the gas production from Phase 1 of Greater Tortue Ahmeyim, Kosmos has commenced a process with prospective buyers to utilize existing contractual rights under our existing Tortue Phase 1 SPA to potentially sell cargos in order to benefit from the robust gas price outlook, while meeting our contractual obligations to BPGM. BPGM has disagreed with our position, and the parties have agreed to pursue international arbitration to interpret the relevant terms of the SPA.

The geographic locations of our licenses in Africa and the U.S. Gulf of Mexico subject us to a risk of loss of revenue or curtailment of production from factors specifically affecting those areas.

A large portion of our current exploration licenses are located in Africa and, following our acquisition of Anadarko WCTP, a significant proportion of our total production comes from the Jubilee Unit Area and TEN Fields offshore Ghana. Some or all of these licenses could be affected should any region experience any of the following factors (among others):

- severe weather, natural or man-made disasters or acts of God;
- delays or decreases in production, the availability of equipment, facilities, personnel or services;
- delays or decreases in the availability of capacity to transport, gather or process production;
- military conflicts, civil unrest or political strife; and/or
- international border disputes.

For example, oil and natural gas operations in our license areas in Africa may be subject to higher political and security risks than those operations under the sovereignty of the United States.

We plan to maintain insurance coverage for only a portion of the risks we face from doing business in these regions. There also may be certain risks covered by insurance where the policy does not reimburse us for all of the costs related to a loss. Further, as many of our licenses are concentrated in the same geographic area, a number of our licenses could experience the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of licenses.

Risks Relating to our Business and Financial Condition

A substantial or extended decline in both global and local oil and natural gas prices may adversely affect our business, financial condition and results of operations.

The prices that we will receive for our oil and natural gas will significantly affect our revenue, profitability, access to capital and future growth rate. Historically, the oil and natural gas markets have been volatile and will likely continue to be volatile in the future. Oil and natural gas prices experienced significant volatility in the past few years and will likely continue to be volatile in the future. For example, Russia’s war in Ukraine, potential instability in the Middle East, a potential regional or global recession, inflationary pressures and other varying macroeconomic conditions and the effects on demand for oil and natural gas has resulted in significant variations in oil and natural gas prices. The prices that we will receive for our production and the levels of our production depend on numerous factors. These factors include, but are not limited to, the following:

- changes in supply and demand for oil and natural gas;
- the actions of the Organization of the Petroleum Exporting Countries;
- speculation as to the future price of oil and natural gas and the speculative trading of oil and natural gas futures contracts;
- global economic conditions;
- political and economic conditions, including embargoes in oil-producing countries or affecting other oil-producing activities, particularly in the Middle East, Africa, Russia and Central and South America;
- the continued threat of terrorism and the impact of military and other action, including U.S. military operations outside the United States;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil inventories and oil refining capacities;
- weather conditions and natural or man-made disasters;
- technological advances affecting energy consumption;
- governmental regulations and taxation policies;
- proximity and capacity of transportation facilities;

- the development and exploitation of alternative fuels or energy sources;
- the price and availability of competitors' supplies of oil and natural gas; and
- the price, availability or mandated use of alternative fuels or energy sources.

Lower oil prices may not only reduce our revenues but also may limit the amount of oil that we can produce economically. A substantial or extended decline in oil and natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. Additionally, a substantial or extended decline in oil and natural gas prices could result in surety companies seeking additional collateral to support existing surety or performance bonds, such as cash or letters of credit, and we cannot provide assurance that we will be able to satisfy such collateral demands. If we are required to provide collateral in the form of cash or letters of credit, our liquidity position could be negatively impacted and we may be required to seek alternative financing. To the extent we are unable to secure adequate financing or obtain surety or performance bonds on commercially reasonable terms, we may be forced to reduce our capital expenditures. These factors may make it more difficult for us to obtain the financial assurances required by the BOEM to conduct operations in the U.S. Gulf of Mexico. These difficulties could result in increased costs on our operations and consequently have a material adverse effect on our business and results of operations.

Our business plan requires substantial additional capital, which we may be unable to raise on acceptable terms or at all in the future, which may in turn limit our ability to develop our exploration, appraisal, development and production activities.

We expect our capital outlays and operating expenditures to be substantial as we expand our operations. Obtaining seismic data, as well as exploration, appraisal, development and production activities entail considerable costs, and we may need to raise substantial additional capital through additional debt financing, asset sales, strategic alliances or future private or public equity offerings if our cash flows from operations, or the timing of, are not sufficient to cover such costs.

Our future capital requirements will depend on many factors, including:

- the scope, rate of progress and cost of our exploration, appraisal, development and production activities;
- the success of our exploration, appraisal, development and production activities;
- oil and natural gas prices;
- our ability to locate and acquire hydrocarbon reserves;
- our ability to produce oil or natural gas from those reserves;
- the terms and timing of any drilling and other production-related arrangements that we may enter into;
- the cost and timing of governmental approvals and/or concessions;
- the effects of competition by other companies operating in the oil and gas industry; and
- potential changes in investor and public preferences and sentiment towards ESG considerations including climate change and the transition to a lower carbon economy.

We do not currently have any commitments for future external funding beyond the capacity of our commercial debt facility and revolving credit facility. Additional financing may not be available on favorable terms, or at all. Even if we succeed in selling additional equity securities to raise funds, at such time the ownership percentage of our existing shareholders would be diluted, and new investors may demand rights, preferences or privileges senior to those of existing shareholders. If we raise additional capital through debt financing, the financing may involve covenants that restrict our business activities. If we choose to farm-out interests in our licenses, we would dilute our ownership interest subject to the farm-out and any potential value resulting therefrom, and may lose operating control or influence over such license areas.

Assuming we are able to commence exploration, appraisal, development and production activities or successfully exploit our licenses during the exploratory term, our interests in our licenses (or the development/production area of such licenses as they existed at that time, as applicable) could extend beyond the term set for the exploratory phase of the license to a fixed period or life of production, depending on the jurisdiction. If we are unable to meet our well commitments and/or declare commerciality of the prospective areas of our licenses during this time, we may be subject to significant potential forfeiture of all or part of the relevant license interests. If we are not successful in raising additional capital, we may be unable to continue our exploration and production activities or successfully exploit our license areas, and we may lose the rights to develop these areas. See "—Under the terms of certain of our petroleum contracts, we are contractually obligated to drill wells and declare any discoveries in order to retain exploration and production rights. In the competitive market for our license areas, failure to drill these wells or declare any discoveries may result in substantial license renewal costs or loss of our interests in the undeveloped parts of our license areas, which may include certain of our prospects or undeveloped discoveries."

All of our proved reserves, oil and natural gas production and cash flows from operations are currently associated with our licenses offshore Ghana, Equatorial Guinea, Mauritania, Senegal and the U.S. Gulf of Mexico. Should any event occur which adversely affects such proved reserves, production and cash flows from these licenses, including, without limitation, any event resulting from the risks and uncertainties outlined in this "Risk Factors" section, our business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures may be materially and adversely affected.

We may be required to take write-downs of the carrying values of our oil and natural gas assets due to decreases in the estimated future net cash flows from our operations, which may occur as a result of decreases in oil and natural gas prices, poor field performance, increased expenditures or changes in the timing or amount of investment, among other things, and such decreases could result in reduced availability under our corporate revolver and commercial debt facility.

We capitalize costs to acquire, find and develop our oil and natural gas properties under the successful efforts accounting method. Under such method, we are required to perform impairment tests on our assets periodically and whenever events or changes in circumstances warrant a review of our assets. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of appraisal and development plans, production data, oil and natural gas prices, economics and other factors, we may be required to write down the carrying value of our oil and natural gas assets. A write-down constitutes a non-cash charge to earnings. For example, if there is a significant and sustained drop in oil and natural gas prices, field performance is not as expected, or we encounter increased expenditures, we may incur future write-downs and charges.

In addition, our borrowing base under the commercial debt facility is subject to periodic redeterminations. We could be forced to repay a portion of our borrowings under the commercial debt facility due to redeterminations of our borrowing base. Redeterminations may occur as a result of a variety of factors, including oil and natural gas commodity price assumptions, assumptions regarding future production from our oil and natural gas assets, operating costs and tax burdens or assumptions concerning our future holdings of proved reserves. If we are forced to do so, we may not have sufficient funds to make such repayments. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

We face various risks associated with increased activism against, or change in public sentiment for, oil and gas exploration development, and production activities and ESG considerations, including climate change and the transition to a lower carbon economy.

Opposition toward oil and gas drilling, development, and production activity has been growing globally. Companies in the oil and gas industry are often the target of activist efforts from both individuals and non-governmental organizations and other stakeholders regarding safety, human rights, climate change, environmental matters, sustainability, and business practices. Certain of these activists are working to, among other things, delay or cancel certain operations such as offshore drilling and development.

Future activist efforts could result in the following:

- delay or denial of drilling permits;
- shortening of lease terms or reduction in lease size;
- restrictions or delays on our ability to obtain additional seismic data;
- restrictions on installation or operation of gathering or processing facilities;
- restrictions on the use of certain operating practices;
- legal challenges or lawsuits;
- pressure or requirements for more analysis and disclosure of environmental and climate change-related risks and data, such as greenhouse gas emissions data;

- damaging publicity about us;
- increased regulation;
- increased costs of doing business;
- reduced access to financing and hedging;
- reduction in demand for our products; and
- other adverse effects on our ability to develop our properties and/or undertake production operations.

Activism may continue to increase regardless of whether the Biden administration in the U.S. is perceived to be following, or actually follows, through on President Biden's campaign commitments to promote decreased fossil fuel exploration and production in the U.S., including as a result of President Biden's environmental and climate change executive orders described later in this 10-K in the risk factor titled "*Our business, operations and financial condition may be directly and indirectly adversely affected by political, economic, and environmental circumstances, and changes in laws and regulations, in the countries and regions in which we operate.*" Our need to incur costs associated with responding to these initiatives or complying with any resulting new legal or regulatory requirements resulting from these activities that are substantial and not adequately provided for, could have a material adverse effect on our business, financial condition and results of operations. In addition, a change in public sentiment regarding the oil and gas industry could result in a reduction in the demand for our products or otherwise affect our results of operations or financial condition.

Outbreaks of disease may adversely affect our business operations and financial condition.

Significant outbreaks of contagious diseases, and other adverse public health developments, could have a material impact on our business operations and financial condition. Many of our operations are currently, and will likely remain in the near future, in developing countries which are susceptible to outbreaks of disease and may lack the resources to effectively contain such an outbreak quickly. Such outbreaks may impact our ability to explore for oil and gas, develop or produce our license areas by limiting access to qualified personnel, increasing costs associated with ensuring the safety and health of our personnel, restricting transportation of personnel, equipment, supplies and oil and gas production to and from our areas of operation and diverting the time, attention and resources of government agencies which are necessary to conduct our operations. In addition, any losses we experience as a result of such outbreaks of disease which impact sales or delay production may not be covered by our insurance policies.

For example, an epidemic of the Ebola virus disease occurred in parts of West Africa in 2014 and continued through 2015. A substantial number of deaths were reported by the World Health Organization ("WHO") in West Africa, and the WHO declared it a global health emergency. Likewise, the global spread of the COVID-19 pandemic resulted in travel restrictions, "shelter-in-place" and various quarantine measures and other governmental actions taken to inhibit its spread and created significant volatility, uncertainty and economic disruption in the markets in which we operate, which affected our business and operations and those of our suppliers, contractors and partners. It is impossible to predict the effect and potential spread of new outbreaks of the Ebola virus, COVID-19 or other viruses in West Africa and surrounding areas. Should another Ebola, COVID-19 or other virus outbreak occur, including to the countries in which we operate, or not be satisfactorily contained, our exploration, development and production plans for our operations could be delayed, or interrupted after commencement. Any changes to these operations could significantly increase costs of operations. Our operations require contractors and personnel to travel to and from Africa as well as the unhindered transportation of equipment and oil and gas production (in the case of our producing fields). Such operations also rely on infrastructure, contractors and personnel in Africa. If travel bans are implemented or extended to the countries in which we operate, or contractors or personnel refuse to travel there, we could be adversely affected. If services are obtained, costs associated with those services could be significantly higher than planned which could have a material adverse effect on our business, results of operations, and future cash flow. In addition, should an Ebola, COVID-19 or other virus outbreak spread to the countries in which we operate, access to the FPSOs could be restricted and/or terminated. The FPSOs are potentially able to operate for a short period of time without access to the mainland, but if restrictions extended for a longer period we and the operator of the impacted fields would likely be required to cease production and other operations until such restrictions were lifted.

These or any further political or governmental developments or health concerns could result in social, economic and labor instability. These uncertainties could have a material impact on our business operations and financial condition.

Deterioration in the credit or equity markets could adversely affect us.

We have exposure to different counterparties. For example, we have entered or may enter into transactions with counterparties in the financial services industry, including commercial banks, investment banks, insurance companies, investment funds, and other institutions. These transactions expose us to credit risk in the event of default by our counterparty. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill existing obligations to us and their willingness to enter into future transactions with us. We may have exposure to these financial institutions through any derivative transactions we have or may enter into. Moreover, to the extent that purchasers of our future production, if any, rely on access to the credit or equity markets to fund their operations, there is a risk that those purchasers could default in their contractual obligations to us if such purchasers were unable to access the credit or equity markets for an extended period of time.

We may incur substantial losses and become subject to liability claims as a result of future oil and natural gas operations, for which we may not have adequate insurance coverage.

We intend to maintain insurance against certain risks in the operation of the business we plan to develop and in amounts in which we believe to be reasonable. Such insurance, however, may contain exclusions and limitations on coverage or may not be available at a reasonable cost or at all. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition and results of operations. Further, even in instances where we maintain adequate insurance coverage, potential delays related to receipt of insurance proceeds as well as delays associated with the repair or rebuilding of damaged facilities could also materially and adversely affect our business, financial condition and results of operations.

Slower global economic growth rates may materially adversely impact our operating results and financial position.

Market volatility and reduced consumer demand due to inflationary pressures or otherwise may increase economic uncertainty. Global economic growth drives demand for energy from all sources, including hydrocarbons. A lower future economic growth rate is likely to result in decreased demand growth for crude oil and natural gas production. A decrease in demand, notwithstanding impacts from other factors, could potentially result in lower commodity prices, which would reduce our cash flows from operations, our profitability and our liquidity and financial position.

Increased costs and availability of capital could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in credit rating. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows available for drilling and place us at a competitive disadvantage. Recent and continuing disruptions and volatility in the global financial markets and a potential regional or global recession which have led to an increase in interest rates during 2023 or a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

Our derivative activities could result in financial losses or could reduce our income.

To achieve more predictable cash flows and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we have and may in the future enter into derivative arrangements for a portion of our oil and natural gas production, including, but not limited to, puts, collars and fixed-price swaps. In addition, we may in the future, hold swaps designed to hedge our interest rate risk. We do not currently designate any of our derivative instruments as hedges for accounting purposes and record all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

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;
- the counter-party to the derivative instrument defaults on its contract obligations; or

- there is an increase in the differential between the underlying price and actual prices received in the derivative instrument.

These types of derivative arrangements may limit the benefit we could receive from increases in the prices for oil and natural gas or beneficial interest rate fluctuations and may expose us to cash margin requirements. In addition, a reduction in our ability to access credit could reduce our ability to implement derivative arrangements on commercially reasonable terms.

Our commercial debt facility, revolving credit facility and the indentures governing our Senior Notes contain certain covenants that may inhibit our ability to make certain investments, incur additional indebtedness and engage in certain other transactions, which could adversely affect our ability to meet our future goals.

Our commercial debt facility, revolving credit facility and the indentures governing our Senior Notes include certain covenants that, among other things, restrict:

- our investments, loans and advances and certain of our subsidiaries' payment of dividends and other restricted payments;
- our incurrence of additional indebtedness;
- the granting of liens, other than liens created pursuant to the commercial debt facility, revolving credit facility, or the indentures governing our Senior Notes and certain permitted liens;
- mergers, consolidations and sales of all or a substantial part of our business or licenses;
- the hedging, forward sale or swap of our production of crude oil or natural gas or other commodities;
- the sale of assets (other than production sold in the ordinary course of business); and
- in the case of the commercial debt facility and the revolving credit facility, our capital expenditures that we can fund with the proceeds of our commercial debt facility and revolving credit facility.

Our commercial debt facility and revolving credit facility require us to maintain certain financial ratios, such as debt service coverage ratios and cash flow coverage ratios. All of these restrictive covenants may limit our ability to move funds among our subsidiaries, operate our business, or expand or pursue our business strategies. Our ability to comply with these and other provisions of our commercial debt facility, revolving credit facility and the indentures governing our Senior Notes may be impacted by changes in economic or business conditions, our results of operations or events beyond our control. The breach of any of these covenants could result in a default under our commercial debt facility, revolving credit facility and the indentures governing our Senior Notes, in which case, depending on the actions taken by the lenders thereunder or their successors or assignees, such lenders could elect to declare all amounts borrowed under such debt instruments, together with accrued interest, to be due and payable. If we were unable to repay such borrowings or interest, our lenders, successors or assignees could proceed against their collateral. If the indebtedness under our commercial debt facility, revolving credit facility and the indentures governing our Senior Notes were to be accelerated, our assets may not be sufficient to repay in full such indebtedness. In addition, the limitations imposed by such debt instruments on our ability to incur additional debt and to take other actions might significantly impair our ability to obtain other financing.

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

Certain provisions of the indentures governing our Senior Notes could make it more difficult or more expensive for a third-party to acquire us, or may even prevent a third-party from acquiring us. For example, upon the occurrence of a "change of control triggering event" (as defined in the indentures governing our Senior Notes), holders of the notes will have the right, at their option, to require us to repurchase all of their notes or any portion of the principal amount of such notes. By discouraging an acquisition of us by a third-party, these provisions could have the effect of depriving the holders of our common stock of an opportunity to sell their common stock at a premium over prevailing market prices.

Our level of indebtedness may increase and thereby reduce our financial flexibility.

At December 31, 2023, we had $925.0 million outstanding and $325.0 million of committed undrawn available capacity under our commercial debt facility, subject to borrowing base availability. As of December 31, 2023, there were no borrowings outstanding under the Corporate Revolver and the undrawn availability was $250.0 million. As of December 31, 2023, we had $1.5 billion principal amount of Senior Notes outstanding. In the future, we also may incur significant off-balance sheet obligations and/or significant indebtedness in order to make investments or acquisitions or to explore, appraise or develop our oil and natural gas assets.

Our level of indebtedness could affect our operations in several ways, including the following:

- a significant portion or all of our cash flows, when generated, could be used to service our indebtedness;
- a high level of indebtedness could increase our vulnerability to general adverse economic and industry conditions;
- the covenants contained in the agreements governing our outstanding indebtedness will limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments;
- a high level of indebtedness may place us at a competitive disadvantage compared to our competitors that are less leveraged and therefore, may be able to take advantage of opportunities that our indebtedness could prevent us from pursuing;
- our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- additional hedging instruments may be required as a result of our indebtedness;
- a high level of indebtedness may make it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then-outstanding bank borrowings; and
- a high level of indebtedness may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes.

A high level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future economic performance. General economic conditions, risks associated with exploring for and producing oil and natural gas, oil and natural gas prices and financial, business and other factors affect our operations and our future economic performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flows to pay the interest on our indebtedness and future working capital, borrowings or equity financing may not be available to pay or refinance such indebtedness. Factors that will affect our ability to raise cash through an offering of our equity securities or a refinancing of our indebtedness include financial market conditions, the value of our assets and our performance at the time we need capital.

We are a holding company and our ability to make payments on our outstanding indebtedness, including our Senior Notes, is dependent upon the receipt of funds from our subsidiaries by way of dividends, fees, interest, loans or otherwise.

We are a holding company, and our subsidiaries own all of our assets and conduct all of our operations. Accordingly, our ability to make payments of interest and principal on our outstanding indebtedness, including the Senior Notes, will be dependent on the generation of cash flow by our subsidiaries and their ability to make such cash available to us, by dividend, debt repayment or otherwise. Unless they are guarantors, our subsidiaries will not have any obligation to pay amounts due on the Senior Notes or to make funds available for that purpose. Our subsidiaries may not be able to, or may not be permitted to, make distributions to enable us to make payments in respect of the Senior Notes. Each subsidiary is a distinct legal entity and, under certain circumstances, legal and contractual restrictions may limit our ability to obtain cash from our subsidiaries. The indentures governing our Senior Notes limits the ability of our subsidiaries to incur consensual encumbrances or restrictions on their ability to pay dividends or make other intercompany payments to us, with significant qualifications and exceptions. In addition, the terms of the commercial debt facility limit the ability of the obligors thereunder, including our material operating subsidiaries that hold interests in our assets located offshore Ghana and Equatorial Guinea and their intermediate parent companies to provide cash to us through dividend, debt repayment or intercompany lending. In the event that we do not receive distributions from our subsidiaries, we may be unable to make required principal and interest payments on our indebtedness, including the Senior Notes.

We may be subject to risks in connection with acquisitions and the integration of acquisitions may be difficult.

We periodically evaluate acquisitions of prospects and licenses, reserves and other strategic transactions that appear to fit within our overall business strategy. The successful acquisition of these assets or businesses requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their appropriate differentials;
- development and operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject assets that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the assets to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We may not be entitled to contractual indemnification for environmental liabilities and could acquire assets on an "as is" basis. Acquisitions and other strategic transactions may involve other risks, including:

- diversion of our management's attention to evaluating, negotiating and integrating acquisitions and strategic transactions;
- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of ours while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate organizations; and
- the challenge of attracting and retaining personnel associated with acquired operations.

The process of integrating operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer.

If we fail to realize the anticipated benefits of acquisitions, our results of operations may be adversely affected.

The success of an acquisition will depend, in part, on our ability to realize anticipated growth opportunities from combining the acquired assets or operations with those of ours. Even if a combination is successful, it may not be possible to realize the full benefits we may expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame. Anticipated benefits of an acquisition may be offset by operating losses relating to changes in commodity prices, increased interest expense associated with debt incurred or assumed in connection with the transaction, adverse changes in oil and gas industry conditions, or by risks and uncertainties relating to the exploratory prospects of the combined assets or operations, or an increase in operating or other costs or other difficulties, including the assumption of health, safety, and environmental or other liabilities in connection with the acquisition. If we fail to realize the benefits we anticipate from an acquisition, our results of operations may be adversely affected.

A cyber incident, including a breach of digital security, could result in information theft, data corruption, operational disruption, and/or financial loss.

The oil and gas industry has become increasingly dependent on digital technologies to conduct day-to-day operations including certain exploration, development and production activities. For example, software programs are used to interpret seismic data, manage drilling rigs, conduct reservoir modeling and reserves estimation, and to process and record financial and operating data.

We depend on digital technology, including information systems and related infrastructure as well as cloud application and services, to process and record financial and operating data, communicate with our employees and business partners, analyze seismic and drilling information, estimate quantities of oil and gas reserves and for many other activities related to our business. Our business partners, including vendors, service providers, co-venturers, purchasers of our production, and financial institutions, are also dependent on digital technology. The complexity of the technologies needed to explore for and develop oil and gas in increasingly difficult physical environments, such as deepwater, and global competition for oil and gas resources make certain information more attractive to thieves.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. A cyber-attack could include gaining unauthorized access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or causing operational disruption, or result in denial-of-service on websites. For example, in 2021, the Colonial Pipeline was subject to a ransomware attack that disabled the pipeline for several days, affecting consumers throughout the eastern coast of the United States. A number of U.S. companies have also been subject to cyber-attacks in recent years resulting in unauthorized access to sensitive information and operational disruptions. Certain countries are believed to possess cyber warfare capabilities and are credited with attacks on American companies and government agencies.

Our technologies, systems, networks, and those of our business partners may become the target of cyber-attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. A cyber incident involving our information systems and related infrastructure, or that of our business partners, could disrupt our business plans, harm our reputation and negatively impact our operations. We expect to maintain insurance against some, but not all, of these risks and losses. The occurrence of any of these events, whether or not covered by insurance, could have a material adverse effect on our financial position and results of operations. Although to date we have not experienced any material cyber-attacks, there can be no assurance that we will not be the target of cyber-attacks in the future or suffer such losses related to any cyber-incident. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

Our ability to utilize net operating loss carryforwards may be subject to certain limitations.

Our ability to use our federal net operating losses to offset potential future taxable income and related income taxes that would otherwise be due is dependent upon our generation of future taxable income and we cannot predict with certainty when, or whether, we will generate sufficient taxable income to use all of our net operating losses. In addition, Section 382 of the Internal Revenue Code of 1986, as amended (the “Code”), contains rules that impose an annual limitation on the ability of a company with federal net operating loss carryforwards that undergoes an ownership change, which is generally any change in ownership of more than 50% of its stock (by value) over a three-year period, to utilize its federal net operating loss carryforwards in years after the ownership change. These rules generally operate by focusing on ownership changes among holders owning directly or indirectly 5% or more of the shares of stock of a company or any change in ownership arising from a new issuance of shares of stock by such company.

If we were to undergo an ownership change as a result of future transactions involving our common stock, including a follow-on offering of our common stock or purchases or sales of common stock between 5% holders, our ability to use our federal net operating loss carryforwards may be subject to limitation under Section 382 of the Code. If our federal net operating losses become subject to the limitation under Section 382 of the Code, we may be unable to fully utilize our federal net operating loss carryforwards to offset our taxable income, if any, in future years, which could have a negative impact on our financial position and results of operations.

In addition to the aforementioned federal income tax implications pursuant to Section 382 of the Code, most states follow the general provisions of Section 382 of the Code, either explicitly or implicitly resulting in separate state net operating loss limitations. Any limitation on our ability to use our state net operating loss carryforwards could also have a negative impact on our financial position and results of operations.

Risks Relating to Regulation

Our business, operations and financial condition may be directly and indirectly adversely affected by political, economic, and environmental circumstances, and changes in laws and regulations, in the countries and regions in which we operate.

Oil and natural gas exploration, development and production activities are directly and indirectly subject to political, economic, and environmental uncertainties (including but not limited to those resulting from government elections and changes in energy policies), changes in laws and policies governing operations of companies, expropriation of property, cancellation or modification of contract rights, revocation of consents, approvals or royalty regimes, obtaining various approvals from regulators, foreign exchange restrictions, currency fluctuations, royalty increases, implementation of a carbon tax or cap-and-trade program, increased laws and regulations around climate change, and other risks arising out of governmental sovereignty, as well as risks of loss due to civil strife, acts of war, guerrilla activities, terrorism, acts of sabotage, territorial disputes and insurrection.

For example, the Biden administration has taken a number of actions that may result in stricter environmental, health and safety standards applicable to our operations and those of the oil and gas industry more generally. The Biden Administration issued the "Executive Order on Tackling the Climate Crisis at Home and Abroad" on January 27, 2021 (the "Climate Change Executive Order"). This executive order directed the Secretary of the Interior to halt indefinitely new oil and natural gas leases on federal lands and offshore waters pending completion of a review by the Secretary of the Interior of federal oil and gas permitting and leasing practices in light of the Biden administration's concerns regarding the impact of these activities on the environment and climate. The Secretary of the Interior completed its review of permitting and leasing practices in November 2021 and issued a report recommending, among other things, an increase in royalty rates and financial assurance requirements. Litigation challenging the Climate Change Executive Order's pause on new oil and gas leases commenced soon after the order was issued, and a federal judge subsequently enjoined the Climate Change Executive Order's pause, preventing it from going into effect. In August 2022, the Inflation Reduction Act was passed by the U.S. Congress, and included provisions which required the DOI to hold previously announced offshore lease sales in the Gulf of Mexico and Alaska within two years. Subsequently, the BOEM held Lease Sale 259 in March 2023 and Lease Sale 261 in December 2023. In addition, the Climate Change Executive Order, among other things, establishes climate conditions as an essential element of U.S. foreign policy; establishes a White House office and a climate task force to coordinate and implement the Biden Administration's domestic climate change agenda; directs federal agencies to procure carbon pollution-free electricity and zero-emission vehicles; eliminate fossil fuel subsidies as consistent with applicable law; identifies a goal of a carbon pollution-free power sector by 2035 and a net-zero emissions U.S. economy by 2050; and commits to a goal of conserving at least 30 percent of federal lands and oceans by 2030. Separately, in April 2021, President Biden announced a goal of reducing the United States' greenhouse gas emissions by 50-52% below 2005 levels by 2030.

In addition, President Biden signed another executive order on January 20, 2021, titled "Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis" (the "Health and Environment Executive Order"), which among other things calls for a review of regulations and other executive actions promulgated, issued or adopted during the prior Presidential administration to assess whether they are, in the view of the Biden Administration, sufficiently protective of public health and the environment, including with respect to climate change, and consistent with science. The order also specifically calls for consideration of new regulations regarding methane emissions in the oil and gas sector, reassessment of decisions made by the prior administration limiting the size of certain national monuments, and incorporation of the impact of GHG emissions (known as the "social cost of carbon") in decision making by federal agencies. These actions and any future changes to applicable environmental, health and safety, regulatory and legal requirements promulgated by the current Presidential administration and Congress may restrict our access to additional acreage and new leases in the deepwater U.S. Gulf of Mexico or lead to limitations or delays on our ability to secure additional permits to drill and develop our acreage and leases or otherwise lead to limitations on the scope of our operations, or may lead to increases to our compliance costs. The potential impacts these changes on our future consolidated financial condition, results of operations or cash flows cannot be predicted.

In addition, we are subject both to uncertainties in the application of the tax laws in the countries in which we operate and where we are resident for tax purposes and to possible changes in such tax laws (or the application thereof), each of which could result in an increase in our tax liabilities. These risks may be higher in the developing countries in which we conduct a majority of our activities, as is the case in Ghana, where the GRA has disputed certain tax deductions we had claimed in prior fiscal years' Ghanaian tax returns as non-allowable under the terms of the Ghanaian Petroleum Income Tax Law, as well as non-payment of certain transactional taxes, contractual fiscal obligations and other payments. We have faced, and continue to face, similar tax related disputes with the Senegal, Mauritania, and Equatorial Guinea Tax Administration.

Additionally, monetary sector reform initiatives in the West African Monetary Union and the Central African Economic and Monetary Union, such as through the implementation of Regulation 02/18/ECMAC/UMAC/CM by the Bank of Central African States could restrict or prevent payments being made in a foreign currency; impose restrictions on offshore and onshore foreign currency accounts; and/or restrict or prevent the repatriation of revenues and debt proceeds. The implementation or realization of any of the foregoing could have an adverse impact on our financial condition and results of operations.

In addition, we are subject to uncertainties surrounding the economies and fiscal health of the countries in which we operate. For example, the Republic of Ghana was subject to ratings downgrades on its sovereign debt in 2022 and 2023. In May 2023, the International Monetary Fund Executive Board approved a $3.0 billion, 3-year extended credit facility arrangement to support Ghana’s economic recovery program, and the Ghanaian authorities have since made progress on their comprehensive debt restructuring. Ratings downgrades such as this one in Ghana have affected the Company’s own credit ratings due to concerns over revenue dependence on a single country. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

Our operations in these areas increase our exposure to risks of war, local economic conditions, political disruption, civil disturbance, expropriation, piracy, tribal conflicts and governmental policies that may:

- disrupt our operations;
- require us to incur greater costs for security;
- impact our credit ratings and ability to access capital;
- restrict the movement of funds or limit repatriation of profits;
- lead to U.S. government or international sanctions; or
- limit access to markets for periods of time.

Some countries in the geographic areas where we operate have experienced political instability in the past or are currently experiencing instability. Disruptions may occur in the future, and losses caused by these disruptions may occur that will not be covered by insurance. Consequently, our exploration, development and production activities may be substantially affected by factors which could have a material adverse effect on our results of operations and financial condition. Furthermore, in the event of a dispute arising from non-U.S. operations, we may be subject to the exclusive jurisdiction of courts outside the United States or may not be successful in subjecting non-U.S. persons to the jurisdiction of courts in the United States or international arbitration, which could adversely affect the outcome of such dispute.

Our operations may also be adversely affected by laws and policies of the jurisdictions, including the jurisdictions where our oil and gas operating activities are located as well as the United Kingdom and the Cayman Islands and other jurisdictions in which we do business, that affect foreign trade and taxation. Changes in any of these laws or policies or the implementation thereof could materially and adversely affect our financial position, results of operations and cash flows.

More comprehensive and stringent regulation in the U.S. Gulf of Mexico has materially increased costs and delays in offshore oil and natural gas exploration and production operations.

In the U.S. Gulf of Mexico, regulatory initiatives are continually developed and implemented at the federal level to prevent major well control incidents. The Department of Interior (“DOI”) through the BOEM and the Bureau of Safety and Environmental Enforcement (“BSEE”), has issued a variety of regulations and Notices to Lessees and Operators (“NTLs”), intended to impose additional safety, permitting and certification requirements applicable to exploration, development and production activities in the U.S. Gulf of Mexico. These regulatory initiatives effectively slowed down the pace of drilling and production operations in the U.S. Gulf of Mexico as adjustments were being made in operating procedures, certification requirements and lead times for inspections, drilling applications and permits, and exploration and production plan reviews, and as the federal agencies evolved into their present-day bureaus. On May 15, 2019, BSEE published a final rule with an effective date of July 15, 2019 that revises requirements for well design, well control, casing, cementing, real-time monitoring (RTM), and subsea containment. These revisions modify regulations pertaining to offshore oil and gas drilling, completions, workovers, and decommissioning in accordance with Executive and Secretary of the Interior's Orders. Key features of the well control regulations include requirements for blowout preventers (BOPs), double shear rams, third-party reviews of equipment, real time monitoring data, safe drilling margins, centralizers, inspections and other reforms related to well design and control, casing, cementing and subsea containment. For a discussion of recent drilling and climate change executive orders signed by President

Biden, see the risk factor earlier in this 10-K titled "*Our business, operations and financial condition may be directly and indirectly adversely affected by political, economic and environmental circumstances, and changes in laws and regulations, in the countries and regions in which we operate*."

In addition to the array of new or revised safety, permitting and certification requirements developed and implemented by the DOI in the past few years, there have been a variety of proposals to change existing laws and regulations that could affect offshore development and production, such as, for example, a proposal to significantly increase the minimum financial responsibility demonstration required under the Oil Pollution Act of 1990. To the extent the existing regulatory initiatives implemented and pursued over the past few years or any future restrictions, whether through legislative or regulatory means or increased or broadened permitting and enforcement programs, foster uncertainties or delays in our offshore oil and natural gas development or exploration activities, then such conditions may have a material adverse effect on our business, financial condition and results of operations. Any other new rules, regulations or legal initiatives by BOEM or other governmental authorities, including as a result of the current Presidential administration, that impose more stringent requirements regarding financial assurances, moratoria on new leases or otherwise adversely affecting our offshore activities could result in increased costs. In particular, as noted above, the current Presidential administration supports limitations on oil and gas exploration and production on federal areas. These restrictions and similar restrictions that may be issued in the future may limit our operations and adversely impact our future financial results.

The oil and gas industry, including the acquisition of exploratory licenses, is intensely competitive and many of our competitors possess and employ substantially greater resources than us.

The oil and gas industry is highly competitive in all aspects, including the exploration for, and the development of, new license areas. We operate in a highly competitive environment for acquiring exploratory licenses and hiring and retaining trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than us, which can be particularly important in the areas in which we operate. These companies may be better able to withstand the financial pressures of unsuccessful drilling efforts, sustained periods of volatility in financial markets and generally adverse global and industry-wide economic conditions, and may be better able to absorb the burdens resulting from changes in relevant laws and regulations, which could adversely affect our competitive position. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable licenses and to consummate transactions in a highly competitive environment. Also, there is substantial competition for available capital for investment in the oil and gas industry. As a result of these and other factors, we may not be able to compete successfully in an intensely competitive industry, which could cause a material adverse effect on our results of operations and financial condition.

Participants in the oil and gas industry are subject to numerous laws, regulations, and other legislative instruments that can affect the cost, manner or feasibility of doing business.

Exploration and production activities in the oil and gas industry are subject to local laws and regulations. We may be required to make large expenditures to comply with governmental laws and regulations, particularly in respect of the following matters:

- licenses for drilling operations;
- tax increases, including retroactive claims;
- unitization of oil accumulations;
- local content requirements (including the mandatory use of local partners and vendors); and
- safety, health and environmental requirements, liabilities and obligations, including those related to remediation, investigation or permitting.

Under these and other laws and regulations, we could be liable for personal injuries, property damage and other types of damages. Failure to comply with these laws and regulations also 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, or their interpretations could change, in ways that could substantially increase our costs. These risks may be higher in the developing countries in which we conduct a majority of our operations, where there could be a lack of clarity or lack of consistency in the application of these laws and regulations. Any resulting liabilities, penalties, suspensions or terminations could have a material adverse effect on our financial condition and results of operations.

For example, Ghana's Parliament has enacted the Petroleum Revenue Management Act, the Petroleum Commission Act of 2011, and the 2016 Ghanaian Petroleum Law. There can be no assurance that these laws will not seek to retroactively, either on their face or as interpreted, modify the terms of the agreements governing our license interests in Ghana, including the WCTP and DT petroleum contracts and the Jubilee UUOA, require governmental approval for transactions that effect a direct or indirect change of control of our license interests or otherwise affect our current and future operations in Ghana. Any such changes may have a material adverse effect on our business. We also cannot assure you that government approval will not be needed for direct or indirect transfers of our petroleum agreements or interests thereunder based on existing legislation.

We are subject to numerous health, safety and environmental laws and regulations which may result in material liabilities and costs.

We are subject to various international, foreign, federal, state and local health, safety and environmental laws and regulations governing, among other things, the emission and discharge of pollutants into the ground, air or water, the generation, storage, handling, use, transportation and disposal of regulated materials and the health and safety of our employees, contractors and communities in which our assets are located. We are required to obtain environmental permits from governmental authorities for our operations, including drilling permits for our wells. We maintain policies and processes to comply with these various permits and laws and regulations to which we are subject. If determined that we have violated or failed to comply with such requirements, we could be fined or otherwise sanctioned by regulators, including through the revocation of our permits or the suspension or termination of our operations. Additionally, there is a risk that such requirements could change in the future or become more stringent. If we fail to obtain, maintain or renew permits in a timely manner or at all (due to opposition from partners, community or environmental interest groups, governmental delays or other reasons), or if we face additional requirements imposed as a result of changes in or enactment of laws or regulations, such failure to obtain, maintain or renew permits or such changes in or enactment of laws or regulations could impede or affect our operations, which could have a material adverse effect on our results of operations and financial condition.

We, as an interest owner or as the designated operator of certain of our past, current and future interests, discoveries and prospects, could be held liable for some or all health, safety and environmental costs and liabilities arising out of our actions and omissions as well as those of our block partners, third-party contractors, predecessors or other operators. To the extent we do not address these costs and liabilities or if we do not otherwise satisfy our obligations, our operations could be suspended or terminated. We have contracted with and intend to continue to hire third parties to perform services related to our operations. There is a risk that we may contract with third parties with unsatisfactory health, safety and environmental records or that our contractors may be unwilling or unable to cover any losses associated with their acts and omissions. Accordingly, we could be held liable for all costs and liabilities arising out of their acts or omissions, which could have a material adverse effect on our results of operations and financial condition.

We are not fully insured against all risks and our insurance may not cover any or all health, safety or environmental claims that might arise from our operations or at any of our license areas. If a significant accident or other event occurs and is not covered by insurance, such accident or event could have a material adverse effect on our results of operations and financial condition.

We take measures to prevent the release of regulated substances. If a release of regulated substances were to occur, which may be significant, under certain environmental laws, we could be held responsible for all of the costs relating to any contamination at our current or former facilities and at any third-party waste disposal sites used by us or on our behalf. In addition, offshore oil and natural gas exploration and production involves various hazards, including human exposure to regulated substances, which include naturally occurring radioactive, and other materials. As such, we could be held liable for any and all consequences arising out of human exposure to such substances or for other damage resulting from the release of any regulated or otherwise hazardous substances to the environment, property or to natural resources, or affecting endangered species.

In addition, we expect continued and increasing attention to climate change issues and emissions of GHGs, including methane (a primary component of natural gas) and carbon dioxide (a byproduct of oil and natural gas combustion). For example, in April 2016, 195 nations, including Ghana, Mauritania, Sao Tome and Principe, Senegal and the United States, 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 in effect a successor to the Kyoto Protocol, an international treaty aimed at reducing emissions of GHGs, to which various countries and regions, including Ghana, Mauritania, Sao Tome and Principe and Senegal, are parties. In 2012, the Kyoto Protocol was extended by amendment through 2020 in the so-called Doha Amendment, which entered into force in late December 2020 after the requisite number of parties ratified it in October 2020. In November and December 2023, the international community gathered in Dubai at the 28th Conference to the Parties on the UN Framework Convention on Climate Change ("COP28"), during which multiple announcements were made, including a global agreement that calls for transitioning away from fossil fuels, and a pledge by about 50 oil and gas producing countries to achieve near-zero methane emissions by 2030. Separately, in December 2023, the U.S. EPA announced its final rule regulating methane and volatile organic compounds emissions in the oil and gas industry which, among other things, requires periodic inspections to detect leaks (and subsequent repairs), places stringent restrictions on venting and flaring of methane, and establishes a program whereby third parties can monitor and repot large methane emissions to the EPA. In addition, in March 2022, the SEC proposed rules requiring disclosure of a range of climate change-related information, including, among other things, companies' climate change risk management; short- medium- and long-term climate-related financial risks; and disclosure of Scope 1, Scope 2 and (for certain companies) Scope 3 emissions. The SEC's proposed climate disclosure rules have not yet been finalized, but implementation of the rules as proposed could be costly and time consuming. It cannot be determined at this time what effect the Paris Agreement, COP28, the EPA's final methane emission rules, the SEC's proposed climate change disclosure rules and any other related GHG emissions targets, regulations, executive orders or other requirements, will have on our business, results of operations and financial condition. This legislative and regulatory uncertainty, however, could result in a disruption to our business or operations. For a discussion of recent environmental and climate change executive orders signed by President Biden, see the risk factor earlier in this 10-K titled "*Our business, operations and financial condition may be directly and indirectly adversely affected by political, economic and environmental circumstances, and changes in laws and regulations, in the countries and regions in which we operate.*"

Health, safety and environmental laws and regulations are complex, change frequently and have tended to become increasingly stringent over time. Our costs of complying with current and future climate change, health, safety and environmental laws, the actions or omissions of our block partners and third-party contractors and our liabilities arising from releases of, or exposure to, regulated substances may adversely affect our results of operations and financial condition. See "Item 1. Business—Environmental Matters" for more information.

We may be exposed to assertions concerning or liabilities under the U.S. Foreign Corrupt Practices Act and other anti-corruption laws, and any such assertions or determination that we violated the U.S. Foreign Corrupt Practices Act or other such laws could result in significant costs to Kosmos and have a material adverse effect on our business.

We are subject to the U.S. Foreign Corrupt Practices Act ("FCPA") and other laws that prohibit improper payments or offers of payments to foreign government officials and political parties for the purpose of obtaining or retaining business or otherwise securing an improper business advantage. In addition, the United Kingdom has enacted the Bribery Act of 2010, and we may be subject to that legislation under certain circumstances. We do business and may do additional business in the future in countries and regions in which we may face, directly or indirectly, corrupt demands by officials. We face the risk of unauthorized payments or offers of payments by one of our employees, contractors or consultants. Our existing safeguards and any future improvements may prove to be less than effective in preventing such unauthorized payments, and our employees and consultants may engage in conduct for which we might be held responsible. Violations of the FCPA or other anti-corruption laws may result in severe criminal or civil sanctions, and we may be subject to other liabilities, which could negatively affect our business, operating results and financial condition. In addition, the U.S. government may seek to hold us liable for successor liability for FCPA violations committed by companies in which we invest in (for example, by way of acquiring equity interests in, participating as a joint venture partner with, acquiring the assets of, or entering into certain commercial transactions with) or that we acquire.

While we believe we maintain a robust compliance program (including policies, procedures, and controls) and corresponding compliance culture, from time-to-time assertions may be raised, including by media outlets or competitors, related to our operations or assets which, notwithstanding the lack of veracity of such assertions, may attract the interest of regulators or affect the market perception of Kosmos. On June 3, 2019, the BBC *Panorama* broadcast a television program, which included various assertions concerning the Cayar Offshore Profond and Saint Louis Offshore Profond Blocks offshore Senegal in which the Company holds interests, which we believe are inaccurate and misleading. We, BP (block operator) and the Government of Senegal all promptly issued independent statements strongly refuting these assertions. As noted in our statement, Kosmos conducted extensive pre-transaction due diligence, and we believe we acquired our interests in the blocks in compliance with applicable laws. After the program aired, certain government agencies requested that Kosmos voluntarily provide information related to the Senegal blocks and other blocks. We have cooperated with these requests to ensure that these agencies have an accurate and complete understanding concerning the history of the blocks. After an extensive review lasting over three-years, the SEC informed us in December 2022 that it had closed its investigation with no enforcement action recommended. There can be no assurance that other regulatory bodies will not make further regulatory inquiries or take other actions.

Federal regulatory law could have an adverse effect on our ability to use derivatives to reduce the effect of commodity price, interest rate and other risks associated with our business.

At times, we use derivatives, specifically cash-settled commodity options and interest rate swaps, to hedge risks associated with our business, including commodity price and interest rate risk. The Commodity Futures Trading Commission ("CFTC") has jurisdiction over derivatives, including swaps and cash-settled commodity options, which are regulated as swaps under the Commodity Exchange Act.

Of particular importance to us, the CFTC has implemented regulations that establish position limits for certain futures and economically equivalent swaps and require exchanges to do the same. Certain bona fide hedging positions are exempt from these position limits. As the relevant provisions of these rules for the Company are phased in over the next several years, they may increase costs or, if we are unable to meet the specific requirements of the relevant hedging exemption, we may be subject to certain position limits.

The CFTC has designated certain interest rate swaps for mandatory clearing and exchange trading. The CFTC has not yet proposed rules designating any other classes of swaps, including commodity swaps, for mandatory clearing or exchange trading. The application of the mandatory clearing and trade execution requirements may change the cost and availability of the swaps that the Company uses for hedging.

Swap dealers that we transact with need to comply with margin and segregation requirements for uncleared swaps. While our uncleared swaps are not directly subject to those margin requirements as a result of the fact that they are used by us for hedging purposes, due to the increased costs to dealers for transacting uncleared swaps in general, our costs for these transactions may increase.

The Commodity Exchange Act also requires certain of the counterparties to our derivatives instruments to be registered with the CFTC and be subject to substantial regulation. These requirements could significantly increase the cost of derivatives, reduce the availability of derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing derivatives. If we reduce our use of derivatives as a result of these regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Our revenues could also be adversely affected if a consequence of the legislation and regulations is to lower commodity prices.

The European Union and other non-U.S. jurisdictions have also implemented or are implementing similar regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we or our transactions may become subject to such regulations. The impact of such regulations could be similar to those described above with respect to U.S. rules.

Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

General Risk Factors

We are dependent on certain members of our management and technical team.

Our performance and success largely depend on the ability, expertise, judgment and discretion of our management and the ability of our technical team to identify, discover, evaluate, develop, and produce reserves. The loss or departure of one or more members of our management and technical team could be detrimental to our future success. Additionally, a significant amount of shares in Kosmos held by members of our management and technical team has vested. There can be no assurance that our management and technical team will remain in place. If any of these officers or other key personnel retires, resigns or becomes unable to continue in their present roles and is not adequately replaced, our results of operations and financial condition could be materially adversely affected. Our ability to manage our growth, if any, will require us to continue to train, motivate and manage our employees and to attract, motivate and retain additional qualified personnel. Competition for these types of personnel is intense, and we may not be successful in attracting, assimilating and retaining the personnel required to grow and operate our business profitably.

We operate in a litigious environment.

Some of the jurisdictions within which we operate have proven to be litigious environments. Oil and gas companies, such as us, can be involved in various legal proceedings, such as title or contractual disputes, in the ordinary course of business.

From time to time, we may become involved in various legal and regulatory proceedings arising in the normal course of business. We cannot predict the occurrence or outcome of these proceedings with certainty, and if we are unsuccessful in these disputes and any loss exceeds our available insurance, this could have a material adverse effect on our results of operations.

Because we maintain a diversified portfolio of assets overseas, the complexity and types of legal procedures with which we may become involved may vary, and we could incur significant legal and support expenses in different jurisdictions. If we are not able to successfully defend ourselves, there could be a delay or even halt in our exploration, development or production activities or other business plans, resulting in a reduction in reserves, loss of production and reduced cash flows. Legal proceedings could result in a substantial liability and/or negative publicity about us and adversely affect the price of our common stock. In addition, legal proceedings distract management and other personnel from their primary responsibilities.

We face various risks associated with global populism.

Globally, certain individuals and organizations are attempting to focus public attention on income distribution, wealth distribution, and corporate taxation levels, and implement income and wealth redistribution policies. These efforts, if they gain political traction, could result in increased taxation on individuals and/or corporations, as well as, potentially, increased regulation on companies and financial institutions. Our need to incur costs associated with responding to these developments or complying with any resulting new legal or regulatory requirements, as well as any potential increased tax expense, could increase our costs of doing business, reduce our financial flexibility and otherwise have a material adverse effect on our business, financial condition and results of our operations.

Our share price may be volatile, and purchasers of our common stock could incur substantial losses.

Our share price may be volatile. The stock market in general has experienced extreme volatility that has often been unrelated to the operating performance of particular companies. The market price for our common stock may be influenced by many factors, including, but not limited to:

- the price of oil and natural gas;
- the success of our exploration and development operations, and the marketing of any oil and natural gas we produce;
- operational incidents;
- regulatory developments in the United States and foreign countries where we operate;
- the recruitment or departure of key personnel;
- quarterly or annual variations in our financial results or those of companies that are perceived to be similar to us;
- market conditions in the industries in which we compete and issuance of new or changed securities;
- analysts' reports or recommendations;
- the failure of securities analysts to cover our common stock or changes in financial estimates by analysts;
- the inability to meet the financial estimates of analysts who follow our common stock;
- the issuance or sale of any additional securities of ours;
- investor perception of our company and of the industry in which we compete; and
- general economic, political and market conditions.

Holders of our common stock will be diluted if additional shares are issued.

We may issue additional shares of common stock, securities that are convertible into shares of common stock, preferred shares, warrants, rights, units and debt securities for general corporate purposes, including, but not limited to, repayment or refinancing of borrowings, working capital, capital expenditures, investments and acquisitions. We continue to actively seek to expand our business through complementary or strategic acquisitions, and we may issue additional shares of common stock in connection with those acquisitions. We also issue restricted share units to our executive officers, employees and independent directors as part of their compensation. If we issue additional shares of common stock or securities that are convertible into shares of common stock in the future, it may have a dilutive effect on our current outstanding shareholders.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 1C. Cybersecurity

See “Item 1. Business - Cybersecurity.”

Item 2. Properties

See “Item 1. Business.” We also have various operating leases for rental of office space, office and field equipment, and vehicles. See “Item 8. Financial Statements and Supplementary Data—Note 15—Commitments and Contingencies” for the future minimum rental payments. Such information is incorporated herein by reference.

Item 3. Legal Proceedings

From time to time, we may be involved in various legal and regulatory proceedings arising in the normal course of business. While we cannot predict the occurrence or outcome of these proceedings with certainty, we do not believe that an adverse result in any pending legal or regulatory proceeding, individually or in the aggregate, would be material to our consolidated financial condition or cash flows; however, an unfavorable outcome could have a material adverse effect on our results of operations for a specific interim period or year.

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

Common Stock Trading Summary

Our common stock is traded on the NYSE and LSE under the symbol KOS.

As of February 22, 2024, based on information from the Company's transfer agent, Computershare Trust Company, N.A., the number of holders of record of Kosmos' common stock was 122. On February 22, 2024, the last reported sale price of Kosmos' common stock, as reported on the NYSE, was $5.93 per share.

Kosmos does not currently pay a dividend. Any decision to pay dividends in the future is at the discretion of our Board of Directors and depends on our financial condition, results of operations, capital requirements and other factors that our Board of Directors deems relevant. Certain of our subsidiaries are currently restricted in their ability to pay dividends to us pursuant to the terms of the Senior Notes, the Facility, and the Corporate Revolver unless we meet certain conditions, financial and otherwise.

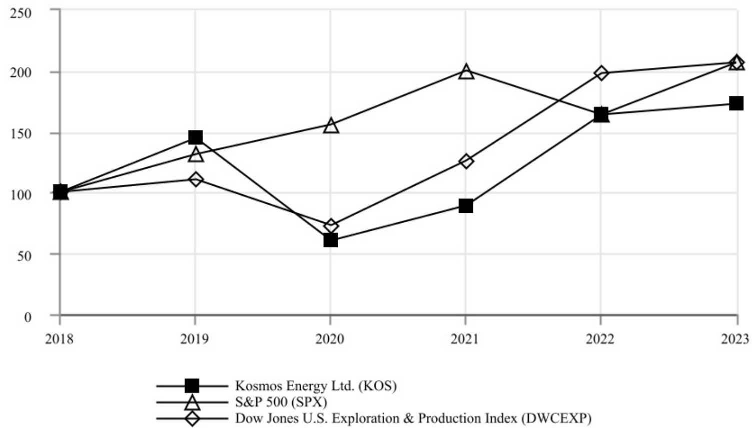
Issuer Purchases of Equity Securities

Under the terms of our LTIP, we have issued restricted share units to our employees. On the date that these restricted share units vest, we provide such employees the option to sell shares to cover their tax liability, via a net exercise provision pursuant to our applicable restricted share unit award agreements and the LTIP, at either the number of vested share units (based on the closing price of our common stock on such vesting date) equal to the minimum statutory tax liability owed by such grantee or up to the maximum statutory tax liability for such grantee. Alternatively, the Company may repurchase the restricted share units sold by the grantees to settle their tax liability. The repurchased share units are reallocated to the number of share units available for issuance under the LTIP.

Share Performance Graph

The following Performance Graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filings under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filings.

The following graph illustrates changes over the five-year period ended December 31, 2023, in cumulative total stockholder return on our common stock as measured against the cumulative total return of the S&P 500 Index and the Dow Jones U.S. Exploration & Production Index. The graph tracks the performance of a $100 investment in our common stock and in each index (with the reinvestment of all dividends).



	December 31,					
	2018	2019	2020	2021	2022	2023
Kosmos Energy Ltd. (KOS)	$ 100.00	$ 144.30	$ 60.50	$ 89.10	$ 163.80	$ 172.80
S&P 500 (SPX)	100.00	131.50	155.60	200.30	164.00	207.00
Dow Jones U.S. Exploration & Production Index (DWCEXP)	100.00	110.30	73.00	125.90	198.10	206.90

Item 6. Selected Financial Data

See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Item 8. Financial Statements and Supplementary Data” for consolidated financial information as of and for the three years ended December 31, 2023.

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

The following discussion and analysis contains forward-looking statements that involve risks and uncertainties. Our actual results may differ materially from those discussed in the forward-looking statements as a result of various factors, including, without limitation, those set forth in "Cautionary Statement Regarding Forward-Looking Statements" and "Item 1A. Risk Factors." The following discussion of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and the notes thereto included elsewhere in this annual report on Form 10-K.

Overview

Kosmos is a full-cycle, deepwater, independent oil and gas exploration and production company focused along the offshore Atlantic Margins. Our key assets include production offshore Ghana, Equatorial Guinea and the U.S. Gulf of Mexico, as well as world-class gas projects offshore Mauritania and Senegal. We also pursue a proven basin exploration program in Equatorial Guinea and the U.S. Gulf of Mexico.

Globally, the impacts of Russia's war in Ukraine, potential instability in the Middle East, a potential recession, inflationary pressures and other varying macroeconomic conditions has impacted supply and demand for oil and gas, which also resulted in significant variability in oil and gas prices. The Company's revenues, earnings, cash flows, capital investments, debt capacity and, ultimately, future rate of growth are highly dependent on these commodity prices.

Recent Developments

Corporate

In September 2023, the Company repaid the remaining outstanding principal amount of the GoM Term Loan in the amount of $137.5 million plus accrued interest using cash on hand, constituting payment in full. The GoM Term Loan was subsequently terminated pursuant to, and subject to the terms of, the GoM Term Loan.

In September 2023, the Company amended the Facility to accede Kosmos Energy Ghana Investments and Kosmos Energy Ghana Holdings Limited, to the Facility as obligors. As a result, the additional interests in Jubilee and TEN that were acquired in the October 2021 acquisition of Anadarko WCTP are now included when calculating the borrowing base amount for the Facility.

In October 2023, the Company amended the Facility to modify the amortization schedule in order to reduce the number of repayment installments from seven to six equal installments, with the first repayment installment scheduled on October 1, 2024, rather than March 31, 2024. There was no change to the final maturity date or final repayment date.

Ghana

During the year ended December 31, 2023, Ghana production averaged approximately 118,200 Boepd gross (38,600 Boepd net).

The phased development of the Jubilee Field continued during 2023 successfully bringing four production wells and two injection wells online which included three wells (two production wells and one injection well) as part of the successful startup of the Jubilee Southeast project. The Jubilee Southeast project also included the installation of a new subsea production manifold. The development drilling campaign is planned to continue in 2024. One new injection well and one new production well were brought online early in the first quarter of 2024. The partnership expects to bring an additional three wells online in 2024 including two production wells and one injection well before we expect the rig contract to end.

In connection with the approval of the Jubilee Phase 1 PoD in 2009, the Jubilee Field partners agreed to provide the first 200 Bcf of natural gas produced from the Jubilee Field Phase 1 development to the Government of Ghana at no cost. As of January 1, 2023, the Jubilee partners had fulfilled this commitment. From 2018 through 2022, approximately 19 Bcf of the first 200 Bcf of natural gas was substituted from the TEN Fields in order to maintain consistent gas volumes to shore for Ghana domestic power purposes. Commencing on January 1, 2023, the volume of approximately 19 Bcf of Jubilee gas (in restoration of the amount originally substituted from TEN) was sold to Ghana under the terms of the TAG GSA at $0.50 per MMBtu. During 2023, the Jubilee partners reached an interim agreement to sell Jubilee Field gas at a price of $2.95 per MMBtu to the Government of Ghana beyond the 19 Bcf from the Jubilee Field through May 2024 while the partners continue on-going discussions with the Government of Ghana regarding a long-term future gas sales agreement. During the second quarter of 2023, the operator submitted a draft amended plan of development for TEN, as well as a term sheet for a gas sales agreement covering future gas sales from both the Jubilee and TEN Fields, to the Government of Ghana. If the amended plan of development for TEN is delayed or not approved, it could lead to a curtailment or delay of investment and development activity in TEN.

U.S. Gulf of Mexico

During the year ended December 31, 2023, U.S. Gulf of Mexico production averaged approximately 15,400 Boepd (net) (~81% oil).

The Kodiak #3 infill well located in Mississippi Canyon was brought online in April 2021. The well experienced production issues and was shut-in. In March 2022, the Company commenced operations to plug back and side-track the original Kodiak #3 infill well. The Kodiak-3ST well was brought online in early September 2022. Well results and initial production were in line with expectations, however well productivity declined through the end of the third quarter of 2022. Workover plans have been developed and are now expected to commence around the middle of 2024 given the better than forecast performance of the well in 2023.

The Winterfell development project continued to make good progress during 2023 with first oil for Phase 1A of the project targeted for early in the second quarter of 2024 with production from the first two wells. The Winterfell-3 well is expected to commence drilling later in 2024. The host facility production handling agreement and oil export agreements have been executed.

The Odd Job Field subsea pump installation project was approximately 90% complete as of the end of 2023 with an expected online date in the middle of 2024. The project is expected to sustain long-term production from the Odd Job Field.

In July 2023, Kosmos spud the Tiberius infrastructure-led exploration prospect, which is located in Block 964 of Keathley Canyon (33% working interest) in the Outer Wilcox play. In October 2023, we announced the well encountered approximately 75 meters (250 feet) of net oil pay in the primary Wilcox target. Initial fluid and core analysis supports the production potential of the wells, with characteristics analogous with similar nearby discoveries in the Wilcox trend. We are now working with partners on development options for the discovery. During the fourth quarter of 2024, Kosmos was named the apparent high bidder on five blocks in the U.S. Gulf of Mexico Lease Sale 261, including three blocks nearby to our Tiberius discovery.

Equatorial Guinea

Production in Equatorial Guinea averaged approximately 25,300 Bopd gross (8,800 Bopd net) for the year ended December 31, 2023.

The 2023 Ceiba Field and Okume Complex development rig campaign commenced in the fourth quarter of 2023. The campaign initially completed one production well workover. However, as a result of safety issues with the drilling rig, the operator terminated the rig contract in early February 2024. The partnership is seeking to secure an alternative rig and drilling contractor to resume the work, which is planned to include the drilling of in-fill production wells in Block G and the Akeng Deep ILX prospect in Block S.

In February 2023, Kosmos entered into a petroleum contract covering Block EG-01 offshore Equatorial Guinea with the Republic of Equatorial Guinea. Kosmos holds a 24% non-operated participating interest in the block. Block EG-01 currently comprises approximately 59,400 acres (240 square kilometers), with a first exploration period of three years from the effective date (March 1, 2023).

In March 2023, we closed a farm-out agreement to sell a 6.0% participating interest in Block S offshore Equatorial Guinea. As a result of the farm-out agreement, Kosmos' participating interest in Block S was reduced to 34.0%.

Mauritania and Senegal

Greater Tortue Ahmeyim Unit

Phase 1 of the Greater Tortue project continued to progress in 2023. The following milestones were achieved through the year-end and filing date:

- Drilling: The operator has successfully drilled and completed all four wells with expected production capacity significantly higher than what is required for first gas.

- Hub Terminal: Construction work is complete, and handover to operations was completed in August 2023.

- Subsea: Significant progress has been made on the installation of the infield flowlines and subsea structures. Work re-commenced in the fourth quarter of 2023 with completion expected at the end of the second quarter of 2024. BP, on behalf of the partner group, has initiated the process under its agreement with the original subsea contractor to recover the losses incurred. The partnership will seek to recover the maximum recoverable damages in binding arbitration. We estimate Kosmos' net share of the recoverable damages to be up to $160.0 million.

- FLNG: The FLNG construction was completed in the fourth quarter of 2023 and the vessel arrived on location offshore Mauritania/Senegal in the first quarter of 2024. Hookup work is now underway.

- FPSO: The vessel is currently in a shipyard in Tenerife for inspection and repair of fairleads. Completion of this work and transit to the project site is expected early in the second quarter of 2024 ahead of final hookup and commissioning.

The critical path to first gas on Phase 1 of the Greater Tortue Ahmeyim project, now targeted in the third quarter of 2024, continues to be through the arrival, hookup and commissioning of the FPSO. Timely execution of this workstream is expected to allow for first LNG in the fourth quarter of 2024.

Yakaar and Teranga Discoveries

The Yakaar and Teranga discoveries continue to be analyzed as a joint development. During 2023, we continued progressing appraisal studies, maturing concept design, and proposed to partners that the Yakaar and Teranga discoveries in the Cayar Offshore Profond Block be pursued as a commercial joint development. PETROSEN agreed to the proposal, however, BP decided not to participate in the development and exploitation of the Yakaar and Teranga discoveries. In accordance with the provisions of the Contract for Exploration and Production Sharing of Hydrocarbons for the Cayar Offshore Profond Block (the "Contract") and the related Joint Operating Agreement (the "JOA"), BP has waived its rights in respect of the Yakaar and Teranga discoveries. As provided in the JOA, Kosmos has assumed BP's participating interest under the Contract and the JOA and has become operator of the Cayar Offshore Profond Block, with customary government approvals having been received effective January 18, 2024. The participating interests in the Cayar Offshore Profond Block are now: Kosmos 90% and PETROSEN 10%, with PETROSEN having the right to increase its participating interest after issuance of an exploitation authorization to up to 35%.

Sao Tome and Principe

In the second quarter of 2023, we received approval for a twelve month extension to May 2024 for the current exploration phase for Block 5 offshore Sao Tome and Principe.

Results of Operations

All of our results, as presented in the table below, represent operations from Ghana, the U.S. Gulf of Mexico and Equatorial Guinea. Certain operating results and statistics for the years ended December 31, 2023, 2022 and 2021 are included in the following tables. For a discussion of the year ended December 31, 2022 compared to the year ended December 31, 2021, please refer to Part II, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Annual Report on Form 10-K for the year ended December 31, 2022.

	Years ended December 31,		
	2023	2022(2)	2021(1)
	(In thousands, except per volume data)		
Sales volumes:			
Oil (MBbl)	20,385	22,012	18,525
Gas (MMcf)	13,737	4,076	4,904
NGL (MBbl)	382	426	508
Total (MBoe)	23,057	23,117	19,850
Total (Boepd)	63,168	63,335	54,384
Revenues:			
Oil sales	$ 1,658,421	$ 2,201,199	$ 1,298,577
Gas sales	35,307	29,504	18,898
NGL sales	7,880	14,652	14,538
Total revenues	$ 1,701,608	$ 2,245,355	$ 1,332,013
Average oil sales price per Bbl	$ 81.35	$ 100.00	$ 70.10
Average gas sales price per Mcf	2.57	7.24	3.85
Average NGL sales price per Bbl	20.61	34.39	28.62
Average total sales price per Boe	73.80	97.13	67.10
Costs:			
Oil and gas production, excluding workovers	$ 367,375	$ 387,888	$ 332,203
Oil and gas production, workovers	22,722	15,168	13,803
Total oil and gas production costs	$ 390,097	$ 403,056	$ 346,006
Depletion, depreciation and amortization	$ 444,927	$ 498,256	$ 467,221
Average cost per Boe:			
Oil and gas production, excluding workovers	$ 15.93	$ 16.78	$ 16.74
Oil and gas production, workovers	0.99	0.66	0.70
Total oil and gas production costs	16.92	17.44	17.44
Depletion, depreciation and amortization	19.30	21.55	23.54
Total oil and gas production costs, depletion, depreciation and amortization	$ 36.22	$ 38.99	$ 40.98

(1) Includes activity related to our acquisition of additional interests in Ghana commencing October 13, 2021, the acquisition date.

(2) Includes activity related to the pre-emption transaction with Tullow on March 13, 2022.

The discussion of the results of operations and the period-to-period comparisons presented below analyze our historical results. The following discussion may not be indicative of future results.

Year Ended December 31, 2023 vs. 2022

	Years Ended December 31,		Increase
	2023	2022(1)	(Decrease)
		(In thousands)	
Revenues and other income:			
Oil and gas revenue	$ 1,701,608	$ 2,245,355	$ (543,747)
Gain on sale of assets	—	50,471	(50,471)
Other income, net	(73)	3,949	(4,022)
Total revenues and other income	1,701,535	2,299,775	(598,240)
Costs and expenses:			
Oil and gas production	390,097	403,056	(12,959)
Facilities insurance modifications, net	—	6,243	(6,243)
Exploration expenses	42,278	134,230	(91,952)
General and administrative	99,532	100,856	(1,324)
Depletion, depreciation and amortization	444,927	498,256	(53,329)
Impairment of long-lived assets	222,278	449,969	(227,691)
Interest and other financing costs, net	95,904	118,260	(22,356)
Derivatives, net	11,128	260,892	(249,764)
Other expenses, net	23,656	(9,054)	32,710
Total costs and expenses	1,329,800	1,962,708	(632,908)
Income before income taxes	371,735	337,067	34,668
Income tax expense (benefit)	158,215	110,516	47,699
Net income	$ 213,520	$ 226,551	$ (13,031)

(1) Includes activity related to the pre-emption transaction with Tullow on March 13, 2022.

Oil and gas revenue. Oil and gas revenue decreased by $543.7 million during the year ended December 31, 2023 as compared to the year ended December 31, 2022 primarily as a result of lower average oil prices and lower oil production across our portfolio due to natural field decline, partially offset by increased natural gas sales in Ghana for the year ended December 31, 2023. We sold 23,057 MBoe at an average realized price per barrel of oil equivalent of $73.80 in 2023 and 23,117 MBoe at an average realized price per barrel of oil equivalent of $97.13 in 2022.

Gain on sale of assets. During the fourth quarter of 2022, we received $50.0 million from Shell under the terms of our 2020 farm-out agreement.

Oil and gas production. Oil and gas production costs decreased by $13.0 million during the year ended December 31, 2023 as compared to the year ended December 31, 2022 as a result of changes to the production mix across our portfolio.

Exploration expenses. Exploration expenses decreased by $92.0 million during the year ended December 31, 2023, as compared to the year ended December 31, 2022 primarily as a result of the $64.2 million of previously capitalized costs related to the BirAllah and Orca discoveries incurred under the Block C8 license offshore Mauritania that were written off to exploration expense with the expiration of the exploration period of Block C8 during the year ended December 31, 2022, along with $13.7 million of exploration expense recorded in 2022 related to two abandoned Ntomme step out wells in Ghana.

Depletion, depreciation and amortization. Depletion, depreciation and amortization decreased $53.3 million during the year ended December 31, 2023, as compared to the year ended December 31, 2022 as a result of lower depletion per barrel in the current year resulting from a lower cost basis in our TEN Fields due to the impairment loss recorded in the year ended December 31, 2022.

Impairment of long-lived assets. Impairment of long-lived assets decreased $227.7 million during the year ended December 31, 2023, as compared to the year ended December 31, 2022. We recorded an impairment charge of $450.0 million in the year ended December 31, 2022 for the TEN Fields as a result of negative proved oil and gas reserve revisions. We recorded an additional impairment charge on the TEN Fields during 2023 of $222.3 million based on further negative revisions to proved oil and gas reserves associated with the TEN Fields. The additional revisions were primarily driven by a change in the partnership's development work scope for the TEN Fields and well performance.

Interest and other financing costs, net. Interest and other financing costs, net decreased by $22.4 million during the year ended December 31, 2023, as compared to the year ended December 31, 2022 primarily as a result of increased capitalized interest related to the Greater Tortue Ahmeyim project partially offset by increased interest expenses related to higher interest rates.

Derivatives, net. During the years ended December 31, 2023 and 2022, we recorded a loss of $11.1 million and $260.9 million, respectively, on our outstanding hedge positions. The changes recorded were a result of changes in the forward curve of oil prices during the respective periods.

Other expenses, net. Other expenses, net increased $32.7 million during the year ended December 31, 2023, as compared to the year ended December 31, 2022 primarily as a result of approximately $7.4 million of inventory impairments and $7.5 million of other asset write downs in the year ended December 31, 2023 and $11.9 million of insurance proceeds in the year ended December 31, 2022.

Income tax expense (benefit). For the years ended December 31, 2023 and December 31, 2022, our overall effective tax rates were impacted by the difference in our 21% U.S. income tax reporting rate and the 35% statutory tax rates applicable to our Ghanaian and Equatorial Guinean operations, jurisdictions that have a 0% statutory tax rate, jurisdictions where we have incurred losses and have recorded valuation allowances against the corresponding deferred tax assets, and other non-deductible expenses, primarily in the U.S.

Liquidity and Capital Resources

We are actively engaged in an ongoing process of anticipating and meeting our funding requirements related to our strategy as a full-cycle exploration and production company. We have historically met our funding requirements through cash flows generated from our operating activities and obtained additional funding from issuances of equity and debt, as well as partner carries.

Oil prices are historically volatile and could negatively impact our ability to generate sufficient operating cash flows to meet our funding requirements. This volatility could result in wide fluctuations in future oil prices, which could impact our ability to comply with our financial covenants. To partially mitigate this price volatility, we maintain an active hedging program and review our capital spending program on a regular basis. Our investment decisions are based on longer-term commodity prices based on the nature of our projects and development plans. Current commodity prices, combined with our hedging program and our current liquidity position is expected to support our capital program for 2024.

Our future financial condition and liquidity can be impacted by, among other factors, the success of our exploitation, exploration and appraisal drilling programs, the number of commercially viable oil and natural gas discoveries made and the quantities of oil and natural gas discovered, the speed with which we can bring such discoveries to production, the reliability of our oil and gas production facilities, our ability to continuously export oil and gas, our ability to secure and maintain partners and their alignment with respect to capital plans, the actual cost of exploitation, exploration, appraisal and development of our oil and natural gas assets, and coverage of any claims under our insurance policies.

In October 2023, during the Fall 2023 redetermination, the Company's lending syndicate approved a borrowing base for the facility of $1.25 billion increasing undrawn availability. As of December 31, 2023, borrowings under the Facility totaled $925.0 million and the undrawn availability under the facility was $325.0 million. As of December 31, 2023, there were no outstanding borrowings under the Corporate Revolver and the undrawn availability was $250.0 million.

Sources and Uses of Cash

The following table presents the sources and uses of our cash and cash equivalents for the years ended December 31, 2023, 2022 and 2021:

	Years Ended December 31,		
	2023	2022	2021
	(In thousands)		
Sources of cash, cash equivalents and restricted cash:			
Net cash provided by operating activities	$ 765,170	$ 1,130,476	$ 374,344
Net proceeds from issuance of senior notes	—	—	839,375
Net proceeds from issuance of common stock	—	—	136,006
Borrowings under long-term debt	300,000	—	725,000
Advances under production prepayment agreement	—	—	—
Proceeds on sale of assets	—	168,703	6,354
	1,065,170	1,299,179	2,081,079
Uses of cash, cash equivalents and restricted cash:			
Oil and gas assets	932,603	787,297	472,631
Acquisition of oil and gas properties	—	22,078	465,367
Notes receivable from partners	62,247	63,183	41,733
Payments on long-term debt	145,000	405,000	1,050,000
Dividends	166	655	512
Other financing costs	13,214	9,041	25,704
	1,153,230	1,287,254	2,055,947
Increase (decrease) in cash, cash equivalents and restricted cash	$ (88,060)	$ 11,925	$ 25,132

Net cash provided by operating activities. Net cash provided by operating activities in 2023 was $765.2 million compared with net cash provided by operating activities of $1.1 billion in 2022 and $374.3 million in 2021, respectively. The decrease in cash provided by operating activities in the year ended December 31, 2023 when compared to the same period in 2022 is primarily a result of lower average realized oil prices. The increase in cash provided by operating activities in the year ended December 31, 2022 when compared to the same period in 2021 is primarily a result of higher realized oil prices and increased production.

The following table presents our liquidity and financial position as of December 31, 2023 and 2022:

	Years Ended December 31,	
	2023	2022
	(In thousands)	
Borrowings under the Facility	$ 925,000	$ 625,000
7.125% Senior Notes	650,000	650,000
7.750% Senior Notes	400,000	400,000
7.500% Senior Notes	450,000	450,000
GoM Term Loan	—	145,000
Total long-term debt	$ 2,425,000	$ 2,270,000
Cash and cash equivalents	95,345	183,405
Total restricted cash	3,416	3,416
Net debt	$ 2,326,239	$ 2,083,179
Availability under the Facility	$ 325,000	$ 618,034
Availability under the Corporate Revolver	$ 250,000	$ 250,000
Available borrowings plus cash and cash equivalents	$ 670,345	$ 1,051,439

Capital Expenditures and Investments

We expect to incur capital costs as we:

- drill additional infill wells and execute exploitation and production activities in Ghana, Equatorial Guinea and the U.S. Gulf of Mexico;
- execute appraisal and development activities in Ghana, the U.S. Gulf of Mexico, Mauritania and Senegal; and
- execute infrastructure-led exploration and appraisal efforts in the U.S. Gulf of Mexico and Equatorial Guinea.

We have relied on a number of assumptions in budgeting for our future activities. These include the number of wells we plan to drill, our paying interests in our operations including disproportionate payment amounts, the costs involved in developing or participating in the development of a prospect, the timing of third-party projects, the availability of suitable equipment and qualified personnel and our cash flows from operations. We also evaluate potential corporate and asset acquisition opportunities to support and expand our asset portfolio, which may impact our budget assumptions. These assumptions are inherently subject to significant business, political, economic, regulatory, health, environmental and competitive uncertainties, contingencies and risks, all of which are difficult to predict and many of which are beyond our control. We may need to raise additional funds more quickly if market conditions deteriorate; or one or more of our assumptions proves to be incorrect, or if we choose to expand our acquisition, exploration, appraisal, development efforts or any other activity more rapidly than we presently anticipate. We may decide to raise additional funds before we need them if the conditions for raising capital are favorable. We may seek to sell assets, equity or debt securities or obtain additional bank credit facilities. The sale of equity securities could result in dilution to our shareholders. The incurrence of additional indebtedness could result in increased fixed obligations and additional covenants that could restrict our operations.

2024 *Capital Program*

We estimate we will spend approximately $700-$750 million of capital for the year ending December 31, 2024, excluding any acquisitions or divestiture of oil and gas properties during the year. This capital expenditure budget consists of:

- Approximately $250-$300 million related to maintenance activities across our Ghana, Equatorial Guinea and U.S. Gulf of Mexico assets, including infill development drilling and integrity spend;
- Approximately $350-$400 million related to the development of Phase 1 of Greater Tortue Ahmeyim in Mauritania and Senegal and Winterfell in the U.S. Gulf of Mexico;
- Approximately $50-$100 million related to progressing our infrastructure-led exploration and appraisal programs in the U.S. Gulf of Mexico, including Tiberius appraisal activities, and the drilling of the ILX prospect Akeng Deep in Equatorial Guinea, as well as the appraisal plans of our greater gas resources in Mauritania and Senegal, including Phase 2 of Greater Tortue Ahmeyim, Yakaar-Teranga and BirAllah.

The ultimate amount of capital we will spend may fluctuate materially based on market conditions and the success of our exploitation and drilling results among other factors. Our future financial condition and liquidity will be impacted by, among other factors, our level of production of oil and the prices we receive from the sale of oil, our ability to effectively hedge future production volumes, the success of our multi-faceted infrastructure-led exploration and appraisal drilling programs, the number of commercially viable oil and natural gas discoveries made and the quantities of oil and natural gas discovered, the speed with which we can bring such discoveries to production, our partners' alignment with respect to capital plans, and the actual cost of exploitation, exploration, appraisal and development of our oil and natural gas assets, and coverage of any claims under our insurance policies.

Significant Sources of Capital

Facility

The Facility supports our oil and gas exploration, appraisal and development programs and corporate activities. The amount of funds available to be borrowed under the Facility, also known as the borrowing base amount, is determined every March and September. The borrowing base amount is based on the sum of the net present values of net cash flows and relevant capital expenditures reduced by certain percentages as well as value attributable to certain assets' reserves and/or resources in the Jubilee and TEN Fields in Ghana and the Ceiba Field and Okume Complex in Equatorial Guinea.

In October 2023, during the Fall 2023 redetermination, the Company's lending syndicate approved a borrowing base of $1.25 billion. As of December 31, 2023, borrowings under the Facility totaled $925.0 million and the undrawn availability under the facility was $325.0 million.

On November 23, 2022, the Company amended the Facility to update the interest rate benchmark from LIBOR to term SOFR, to be effective as of April 19, 2023. On September 29, 2023, the Company amended the Facility to accede Kosmos Energy Ghana Investments and Kosmos Energy Ghana Holdings Limited to the Facility as obligors. As a result, the additional interests in Jubilee and TEN that were acquired in the October 2021 acquisition of Anadarko WCTP are now included when calculating the borrowing base amount for the Facility, effective as of October 1, 2023. On October 19, 2023, the Company amended the Facility to modify the amortization schedule in order to reduce the number of repayment installments from seven to six equal installments, with the first repayment installment scheduled on October 1, 2024, rather than March 31, 2024. There was no change to the final maturity date or final repayment date.

The Facility provides a revolving credit and letter of credit facility. The availability period for the revolving credit facility expires one month prior to the final maturity date. The letter of credit facility expires on the final maturity date. The available facility amount is subject to borrowing base constraints and, beginning on October 1, 2024, outstanding borrowings will be constrained by an amortization schedule. The Facility has a final maturity date of March 31, 2027. As of December 31, 2023, we had no letters of credit issued under the Facility. We have the right to cancel all the undrawn commitments under the amended and restated Facility.

If an event of default exists under the Facility, the lenders can accelerate the maturity and exercise other rights and remedies, including the enforcement of security granted pursuant to the Facility over certain assets held by our subsidiaries. We were in compliance with the financial covenants contained in the Facility as of September 30, 2023 (the most recent assessment date). The Facility contains customary cross default provisions.

Corporate Revolver

The Corporate Revolver is available for general corporate purposes and for oil and gas exploration, appraisal and development programs. On November 23, 2022, the Company amended the Corporate Revolver to update the interest rate benchmark from compounded SOFR to term SOFR. As of December 31, 2023, there were no outstanding borrowings under the Corporate Revolver and the undrawn availability was $250.0 million.

The available amount is not subject to borrowing base constraints. We have the right to cancel all the undrawn commitments under the Corporate Revolver. We are required to repay certain amounts due under the Corporate Revolver with sales of certain subsidiaries or sales of certain assets. If an event of default exists under the Corporate Revolver, the lenders can accelerate the maturity and exercise other rights and remedies, including the enforcement of security granted pursuant to the Corporate Revolver over certain assets held by us.

We were in compliance with the financial covenants contained in the Corporate Revolver as of September 30, 2023 (the most recent assessment date). The Corporate Revolver contains customary cross default provisions.

The U.S. and many foreign economies continue to experience uncertainty driven by varying macroeconomic conditions. Although some of these economies have shown signs of improvement, macroeconomic recovery remains uneven. Uncertainty in the macroeconomic environment and associated global economic conditions have resulted in extreme volatility in credit, equity, and foreign currency markets, including the European sovereign debt markets and volatility in various other markets. If any of the financial institutions within our Facility or Corporate Revolver are unable to perform on their commitments, our liquidity could be impacted. We actively monitor all of the financial institutions participating in our Facility and Corporate Revolver. None of the financial institutions have indicated to us that they may be unable to perform on their commitments. In addition, we periodically review our banking and financing relationships, considering the stability of the institutions and other aspects of the relationships. Based on our monitoring activities, we currently believe our banks will be able to perform on their commitments.

Senior Notes

We have three series of senior notes outstanding, which we collectively referred to as the “Senior Notes.” Our 7.125% Senior Notes mature on April 4, 2026, and interest is payable on the 7.125% Senior Notes each April 4 and October 4. Our 7.500% Senior Notes mature on March 1, 2028, and interest is payable on the 7.500% Senior Notes each March 1 and September 1. Our 7.750% Senior Notes mature on May 1, 2027, and interest is payable on the 7.750% Senior Notes each May 1 and November 1.

The Senior Notes are senior, unsecured obligations of Kosmos Energy Ltd. and rank equally in right of payment with all of its existing and future senior indebtedness (including all borrowings under the Corporate Revolver) and rank effectively junior in right of payment to all of its existing and future secured indebtedness (including all borrowings under the Facility). The Senior Notes are jointly and severally guaranteed on a senior, unsecured basis by certain subsidiaries owning the Company's U.S. Gulf of Mexico assets, and on a subordinated, unsecured basis by entities that borrow under, or guarantee, our Facility.

GoM Term Loan

In September 2020, the Company entered into a five-year $200 million senior secured term-loan credit agreement secured against the Company's U.S. Gulf of Mexico assets with net proceeds received of $197.7 million after deducting fees and other expenses. On September 15, 2023, the Company repaid the remaining outstanding principal amount of $137.5 million plus accrued interest using cash on hand, constituting payment in full. The GoM Term Loan was subsequently terminated pursuant to, and subject to the terms of, the GoM Term Loan.

Contractual Obligations

The following table presents maturities by expected debt maturity dates, the weighted-average interest rates expected to be paid on the Facility and Corporate Revolver given current contractual terms and market conditions, and the instrument’s estimated fair value. Weighted-average interest rates are based on implied forward rates in the yield curve at the reporting date. This table does not take into account amortization of deferred financing costs.

	Years Ending December 31,							Asset (Liability) Fair Value at December 31,
	2024	2025	2026	2027	2028	Thereafter	Total	2023
	(In thousands, except percentages)							
Fixed rate debt:								
7.125% Senior Notes	$ —	$ —	$ 650,000	$ —	$ —	$ —	$ 650,000	$ 622,824
7.750% Senior Notes	—	—	—	400,000	—	—	400,000	374,764
7.500% Senior Notes	—	—	—	—	450,000	—	450,000	412,461
Variable rate debt:								
Weighted average interest rate	8.91 %	7.69 %	7.85 %	8.19 %	— %	— %		
Facility(1)	$ —	$ 300,000	$ 416,667	$ 208,333	$ —	$ —	$ 925,000	$ 925,000
Total principal debt repayments (1)	$ —	$ 300,000	$ 1,066,667	$ 608,333	$ 450,000	$ —	$ 2,425,000	
Interest & commitment fees on long-term debt	203,273	173,370	121,070	53,517	16,875	—	568,105	
Operating leases(2)	4,124	4,195	4,266	4,205	3,844	2,808	23,442	
Purchase obligations(3)	55,790	—	—	—	—	—	55,790	

(1) The amounts included in the table represent principal maturities only. The scheduled maturities of debt related to the Facility are based on the level of borrowings and the available borrowing base as of December 31, 2023. Any increases or decreases in the level of borrowings or increases or decreases in the available borrowing base would impact the scheduled maturities of debt during the next five years and thereafter.

(2) Primarily relates to corporate office and foreign office leases.

(3) Represents gross contractual obligations to execute planned future capital projects. Other joint owners in the properties operated by Kosmos will be billed for their working interest share of such costs. Does not include our share of operator's purchase commitments for jointly owned fields and facilities where we are not the operator and excludes commitments for exploration activities, including well commitments and seismic obligations, in our petroleum contracts. The Company's liabilities for asset retirement obligations associated with the dismantlement, abandonment and restoration costs of oil and gas properties are not included. See Note 11—Asset Retirement Obligations of Notes to the Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding these liabilities.

We have a commitment to drill three development wells and one exploration well in Equatorial Guinea. We have a $200.2 million FPSO Contract Liability in Other long-term liabilities related to the deferred sale of the Greater Tortue FPSO.

In February 2019, Kosmos and BP signed Carry Advance Agreements with the national oil companies of Mauritania and Senegal, which obligate us separately to finance the respective national oil companies' share of certain development costs. Kosmos' total share for the two agreements combined originally estimated at approximately $300.0 million, of which $259.2 million has been incurred through December 31, 2023, excluding accrued interest. These amounts are expected to be repaid through the national oil companies' share of future revenues.

Critical Accounting Policies

This discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements, which have been prepared in accordance with generally accepted accounting principles in the United States. The preparation of our financial statements requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities as of the date the financial statements are available to be issued. These estimates could change materially if different information or assumptions were used. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates. Our significant accounting policies are detailed in "Item 8. Financial Statements and Supplementary Data—Note 2—Accounting Policies." We have outlined below certain accounting policies that are of particular importance to the presentation of our financial position and results of operations and require the application of significant judgment or estimates by our management.

Revenue Recognition. We recognize revenues on the volumes of hydrocarbons sold to a purchaser. The volumes sold may be more or less than the volumes to which we are entitled based on our ownership interest in the property. These differences result in a condition known in the industry as a production imbalance. A receivable or liability is recognized only to the extent that we have an imbalance on a specific property greater than the expected remaining proved reserves on such property. As of December 31, 2023 and 2022, we had no oil and gas imbalances recorded in our consolidated financial statements.

Our oil and gas revenues are recognized when hydrocarbons have been sold to a purchaser at a fixed or determinable price, title has transferred and collection is probable. Certain revenues are based on contracts with provisional pricing and quantity optionality which contain a derivative that is required to be separated from the host contract for accounting purposes. The host contract is the receivable from oil sales at the spot price on the date of sale. The derivative, which is not designated as a hedge, is marked to market through oil and gas revenue each period until the final settlement occurs, which generally is limited to the month after the sale.

Exploration and Development Costs. We follow the successful efforts method of accounting for our oil and gas properties. Acquisition costs for proved and unproved properties are capitalized when incurred. Costs of unproved properties are transferred to proved properties when a determination that proved reserves have been found. Exploration costs, including geological and geophysical costs and costs of carrying unproved properties, are expensed as incurred. Exploratory drilling costs are capitalized when incurred. If exploratory wells are determined to be commercially unsuccessful or dry holes, the applicable costs are expensed and recorded in exploration expense on the consolidated statement of operations. Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized. Costs incurred to operate and maintain wells and equipment and to lift oil and natural gas to the surface are expensed as oil and gas production expense.

Income Taxes. We account for income taxes as required by the ASC 740—Income Taxes ("ASC 740"). We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments occur in the calculation of certain tax assets and liabilities that arise from differences in the timing and recognition of revenue and expense for tax and financial reporting purposes. Our federal, state and international tax returns are generally not prepared or filed before the consolidated financial statements are prepared; therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of changes in tax laws or tax rates, tax credits, and net operating loss carryforwards. Adjustments related to these estimates are recorded in our tax provision in the period in which we file our income tax returns. Further, we must assess the likelihood that we will be able to realize or utilize our deferred tax assets. If realization is not more likely than not, we must record a valuation allowance against such deferred tax assets for the amount we would not expect to recover, which would result in no benefit for the deferred tax amounts. As of December 31, 2023 and 2022, we have a valuation allowance to reduce certain deferred tax assets to amounts that are more likely than not to be realized. If our estimates and judgments regarding our ability to realize our deferred tax assets change, the benefits associated with those deferred tax assets may increase or decrease in the period our estimates and judgments change. On a quarterly basis, management evaluates the need for and adequacy of valuation allowances based on the expected realizability of the deferred tax assets and adjusts the amount of such allowances, if necessary.

ASC 740 provides a more-likely-than-not standard in evaluating whether a valuation allowance is necessary after weighing all of the available evidence. When evaluating the need for a valuation allowance, we consider all available positive and negative evidence, including the following:

- the status of our operations in the particular taxing jurisdiction, including whether we have commenced production from a commercial discovery;
- whether a commercial discovery has resulted in significant proved reserves that have been independently verified;
- the amounts and history of taxable income or losses in a particular jurisdiction;
- projections of future income, including the sensitivity of such projections to changes in production volumes and prices;
- the existence, or lack thereof, of statutory limitations on the period that net operating losses may be carried forward in a jurisdiction; and
- the creation and timing of future income associated with the reversal of deferred tax liabilities in excess of deferred tax assets.

Estimates of Proved Oil and Natural Gas Reserves. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion and assessment of impairment of our oil and natural gas properties. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. As additional proved reserves are discovered, reserve quantities and future cash flows will be estimated by independent petroleum consultants and prepared in accordance with guidelines established by the SEC and the FASB. The accuracy of these reserve estimates is a function of:

- the engineering and geological interpretation of available data;
- estimates of the amount and timing of future operating cost, production taxes, development cost and workover cost;
- the accuracy of various mandated economic assumptions; and
- the judgments of the persons preparing the estimates.

Asset Retirement Obligations. We account for asset retirement obligations as required by ASC 410 — Asset Retirement and Environmental Obligations. Under these standards, the fair value of a liability for an asset retirement obligation is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. If a reasonable estimate of fair value cannot be made in the period the asset retirement obligation is incurred, the liability is recognized when a reasonable estimate of fair value can be made. If a tangible long-lived asset with an existing asset retirement obligation is acquired, a liability for that obligation is recognized at the asset's acquisition or in service date. In addition, a liability for the fair value of a conditional asset retirement obligation is recorded if the fair value of the liability can be reasonably estimated. We capitalize the asset retirement costs by increasing the carrying amount of the related long-lived asset by the same amount as the liability. We record increases in the discounted abandonment liability resulting from the passage of time in depletion, depreciation and amortization in the consolidated statement of operations. Estimating the future restoration and removal costs requires management to make estimates and judgments because most of the removal obligations are many years in the future and the regulations in some countries that we operate often have vague descriptions of what constitutes removal. Additionally, asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

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. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligations, a corresponding adjustment is made to the oil and gas property balance.

Impairment of Long-lived Assets. We review our long-lived assets for impairment when changes in circumstances indicate that the carrying amount of an asset may not be recoverable. ASC 360 — Property, Plant and Equipment requires an impairment loss to be recognized if the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. The carrying amount of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. That assessment shall be based on the carrying amount of the asset at the date it is tested for recoverability, whether in use or under development. Assets to be disposed of and assets not expected to provide any future service potential to us are recorded at the lower of carrying amount or fair value. Oil and gas properties are grouped in accordance with ASC 932 — Extractive Activities-Oil and Gas. The basis for grouping is a reasonable aggregation of properties typically by field or by logical grouping of assets with significant shared infrastructure.

For long-lived assets whereby the carrying value exceeds the estimated future undiscounted cash flows, the carrying amount is reduced to fair value. Fair value is generally estimated using the income approach described in the ASC 820 — Fair Value Measurement. If applicable, we utilize prices and other relevant information generated by market transactions involving assets and liabilities that are identical or comparable to the item being measured as the basis for determining fair value. The expected future cash flows used for impairment reviews and related fair value measurements are typically based on judgmental assessments of future production, pricing estimates, capital and operating costs, market-based weighted average cost of capital, and risk adjustment factors applied to reserves. These assumptions are applied to develop future cash flow projections that are then discounted to estimated fair value, using a market-based weighted-average cost of capital. Although we base the fair value estimate of each asset group on assumptions we believe to be reasonable, those assumptions are inherently unpredictable and uncertain, and actual results could differ from the estimate. Negative revisions of estimated reserve quantities, increases in future cost estimates, divestiture of a significant component of the asset group, or sustained decreases in crude oil prices could lead to a reduction in expected future cash flows and possibly an additional impairment of long-lived assets in future periods.

We believe the assumptions used in our analysis to test for impairment are appropriate and result in a reasonable estimate of future cash flows and fair value. Kosmos has consistently used an average of third-party industry forecasts to determine our pricing assumptions. Where unproved reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the evaluation.

Acquisition Accounting. The purchase price in an acquisition (business combination or asset acquisition) is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the deal announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired, and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. The most significant estimates in the allocation typically relate to the value assigned to future recoverable oil and natural gas reserves and unproved properties. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain.

New Accounting Pronouncements

See "Item 8. Financial Statements and Supplementary Data—Note 2—Accounting Policies" for a discussion of recent accounting pronouncements.

Item 7A. Qualitative and Quantitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risks" as it relates to our currently anticipated transactions refers to the risk of loss arising from changes in commodity prices and interest rates. These disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage ongoing market risk exposures. We enter into market-risk sensitive instruments for purposes other than to speculate.

We manage market and counterparty credit risk in accordance with our policies. In accordance with these policies and guidelines, our management determines the appropriate timing and extent of derivative transactions. See "Item 8. Financial Statements and Supplementary Data—Note 2—Accounting Policies, Note 9—Derivative Financial Instruments and Note 10—

Fair Value Measurements" for a description of the accounting procedures we follow relative to our derivative financial instruments.

The following table reconciles the changes that occurred in fair values of our open derivative contracts during the year ended December 31, 2023:

	Derivative Contracts Assets (Liabilities) Commodities
	(In thousands)
Fair value of contracts outstanding as of December 31, 2022	$ 2,688
Changes in contract fair value	(28,349)
Contract maturities	32,426
Fair value of contracts outstanding as of December 31, 2023	$ 6,765

Commodity Price Risk

The Company's revenues, earnings, cash flows, capital investments and, ultimately, future rate of growth are highly dependent on the prices we receive for our crude oil, which have historically been very volatile. Substantially all of our oil sales are indexed against Dated Brent and Heavy Louisiana Sweet. Oil prices during 2023 ranged between $71.71 and $97.92 per Bbl for Dated Brent, with Heavy Louisiana Sweet experiencing similar volatility during 2023.

Commodity Derivative Instruments

We enter into various oil derivative contracts to mitigate our exposure to commodity price risk associated with anticipated future oil production. These contracts currently consist of collars, put options, call options and swaps. In regards to our obligations under our various commodity derivative instruments, if our production does not exceed our existing hedged positions, our exposure to our commodity derivative instruments would increase. In addition, a reduction in our ability to access credit could reduce our ability to implement derivative contracts on commercially reasonable terms.

Commodity Price Sensitivity

The following table provides information about our oil derivative financial instruments that were sensitive to changes in oil prices as of December 31, 2023. Volumes and weighted average prices are net of any offsetting derivatives entered into.

				Weighted Average Price per Bbl				
Term	Type of Contract	Index	MBbl	Net Deferred Premium Payable/(Receivable)	Sold Put	Floor	Ceiling	Asset (Liability) Fair Value at December 31, 2022(1)
2024:								(In thousands)
Jan - Dec	Three-way collars	Dated Brent	4,000	1.31	45.00	70.00	96.25	$ 4,477
Jan - Jun	Two-way collars	Dated Brent	2,000	1.24	—	65.00	85.00	$ (3,103)
Jan - Dec	Two-way collars	Dated Brent	2,000	0.46	—	70.00	100.00	$ 5,463

(1) Fair values are based on the average forward oil prices on December 31, 2023.

In January 2024, we entered into Dated Brent three-way collar contracts for 2.0 MMBbl from July 2024 through December 2024 with a sold put price of $45.00 per barrel, a floor price of $70.00 per barrel and a ceiling price of $90.00 per barrel.

At December 31, 2023, our open commodity derivative instruments were in a net asset position of $6.8 million. As of December 31, 2023, a hypothetical 10% price increase in the commodity futures price curves would decrease future pre-tax earnings by approximately $22.2 million. Similarly, a hypothetical 10% price decrease would increase future pre-tax earnings by approximately $23.4 million.

Interest Rate Sensitivity

Changes in market interest rates affect the amount of interest we pay on certain of our borrowings. Outstanding borrowings under the Facility, which as of December 31, 2023 total approximately $925.0 million and has a weighted average interest rate of 9.2%, are subject to variable interest rates, which expose us to the risk of earnings or cash flow loss due to potential increases in market interest rates. If the floating market rate increased 10% at this level of floating rate debt, we would pay an estimated additional $5.0 million interest expense per year. The commitment fees on the undrawn availability under the Facility and the Corporate Revolver are not subject to changes in interest rates. All of our other long-term indebtedness is fixed rate and does not expose us to the risk of cash flow loss due to changes in market interest rates. Additionally, a change in the market interest rates could impact interest costs associated with future debt issuances or any future borrowings and future lease payments associated with the Tortue FPSO lease arrangement.

Item 8. Financial Statements and Supplementary Data

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of Kosmos Energy Ltd.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Kosmos Energy Ltd. (the Company) as of December 31, 2023 and 2022, the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2023, and the related notes and financial statement schedules listed in the Index at Item 15(a) (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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 26, 2024 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's 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 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 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

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

Depletion of oil and gas properties, net

Description of the Matter

At December 31, 2023, the net book value of the Company's oil and gas properties, net was $4.15 billion, and depletion expense was $411.6 million for the year then ended. As described in Note 2, the Company follows the successful efforts method of accounting for its oil and natural gas properties. Proved properties and support equipment and facilities are depleted using the unit of production method based on estimated proved oil and natural gas reserves. Capitalized exploratory drilling costs that result in a discovery of proved reserves and development costs are depleted using the unit-of-production method based on estimated proved developed oil and natural gas reserves for the related field. The Company's oil and natural gas reserves are estimated by independent reserve engineers. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids that demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. Judgment is required by the Company's independent reserve engineers in estimating proved oil and natural gas reserves. Estimating reserves requires the selection of inputs, including historical production, oil and natural gas price assumptions and future operating and capital cost assumptions, among others. Because of the complexity involved in estimating oil and natural gas reserves, management used independent reserve engineers to prepare the estimate of reserve quantities as of December 31, 2023.

Auditing the Company's depletion calculation is complex because of the use of the work of independent reserve engineers and the evaluation of management's determination of the inputs described above used by the independent reserve engineers in estimating proved oil and natural gas reserves.

How We Addressed the Matter in Our Audit

We obtained an understanding, evaluated the design and tested the operating effectiveness of the controls over the Company's process to calculate depletion, including management's controls over the completeness and accuracy of the inputs provided to the independent reserve engineers for use in estimating the proved oil and natural gas reserves.

Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the independent reserve engineers used to prepare the estimate of proved oil and natural gas reserves. We evaluated the completeness, accuracy, relevance, and reliability, as applicable, of the inputs described above used by the independent reserve engineers in estimating proved oil and natural gas reserves by agreeing them to source documentation or performing analytical procedures. We evaluated management's intent and ability to develop proved undeveloped reserves. We tested the mathematical accuracy of the depletion calculations, including comparing the estimated proved oil and natural gas reserve amounts used to the Company's reserve report.

Asset retirement obligations

Description of the Matter

At December 31, 2023, the Company's asset retirement obligations totaled $346.8 million. As described in Note 2, the fair value of a liability for an asset retirement obligation is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. If a tangible long lived asset with an existing asset retirement obligation is acquired, a liability for that obligation is recognized at the asset's acquisition or in-service date. Because of the complexity involved in estimating the expected cash outflows, management used a specialist to estimate the expected cash outflows for the Company's asset retirement obligations as of December 31, 2023.

Auditing the Company's asset retirement obligations was complex and judgmental due to the estimation required by management to determine the estimated present value of the amount of dismantlement, removal, site reclamation and similar activities associated with the Company's oil and natural gas properties. In particular, the estimate was sensitive to assumptions such as the expected cash outflows for asset retirement obligations and the ultimate productive life of the properties.

How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design and tested the operating effectiveness of the controls over the Company’s process to estimate asset retirement obligations, including controls over management’s review of the assumptions described above. Our audit procedures included, among others, testing the assumptions discussed above and the underlying data used by the Company. For example, we evaluated expected cash outflows for asset retirement obligations by comparing to recent offshore activities and costs. We also compared the ultimate productive life of the properties to forecasts of production based on estimates of oil and natural gas reserves, as estimated by independent reserve engineers. We involved our specialists to assist in our evaluation of the expected cash flows for asset retirement obligations.

/s/ Ernst & Young LLP

We have served as the Company’s auditor since 2004.
Dallas, Texas
February 26, 2024

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of Kosmos Energy Ltd.

Opinion on Internal Control Over Financial Reporting

We have audited Kosmos Energy Ltd.'s internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Kosmos Energy Ltd. (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2023, based on the COSO criteria.

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, 2023 and 2022, the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2023, and the related notes and financial statement schedules listed in the Index at Item 15(a) and our report dated February 26, 2024 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 Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ Ernst & Young LLP

Dallas, Texas
February 26, 2024

KOSMOS ENERGY LTD.

CONSOLIDATED BALANCE SHEETS

(In thousands, except share data)

	December 31, 2023	December 31, 2022
Assets		
Current assets:		
Cash and cash equivalents	$ 95,345	$ 183,405
Receivables	120,733	119,735
Inventories	152,054	133,515
Prepaid expenses and other	46,235	24,722
Derivatives	8,346	7,344
Total current assets	422,713	468,721
Property and equipment, net	4,160,229	3,842,647
Other assets:		
Restricted cash	3,416	3,416
Long-term receivables	325,181	235,696
Deferred tax assets	3,033	—
Derivatives	1,594	1,725
Other	21,968	27,783
Total assets	$ 4,938,134	$ 4,579,988
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable	$ 248,912	$ 212,275
Accrued liabilities	302,815	325,206
Current maturities of long-term debt	—	30,000
Derivatives	3,103	6,773
Total current liabilities	554,830	574,254
Long-term liabilities:		
Long-term debt, net	2,390,914	2,195,911
Derivatives	—	778
Asset retirement obligations	343,979	300,800
Deferred tax liabilities	363,918	468,445
Other long-term liabilities	252,156	251,952
Total long-term liabilities	3,350,967	3,217,886
Stockholders' equity:		
Preference shares, $0.01 par value; 200,000,000 authorized shares; zero issued at December 31, 2023 and December 31, 2022	—	—
Common stock, $0.01 par value; 2,000,000,000 authorized shares; 504,392,980 and 500,161,421 issued at December 31, 2023 and December 31, 2022, respectively	5,044	5,002
Additional paid-in capital	2,536,621	2,505,694
Accumulated deficit	(1,272,321)	(1,485,841)
Treasury stock, at cost, 44,263,269 shares at December 31, 2023 and December 31, 2022, respectively	(237,007)	(237,007)
Total stockholders' equity	1,032,337	787,848
Total liabilities and stockholders' equity	$ 4,938,134	$ 4,579,988

See accompanying notes.

KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)

	Years Ended December 31,		
	2023	2022	2021
Revenues and other income:			
Oil and gas revenue	$ 1,701,608	$ 2,245,355	$ 1,332,013
Gain on sale of assets	—	50,471	1,564
Other income, net	(73)	3,949	262
Total revenues and other income	1,701,535	2,299,775	1,333,839
Costs and expenses:			
Oil and gas production	390,097	403,056	346,006
Facilities insurance modifications, net	—	6,243	(1,586)
Exploration expenses	42,278	134,230	65,382
General and administrative	99,532	100,856	91,529
Depletion, depreciation and amortization	444,927	498,256	467,221
Impairment of long-lived assets	222,278	449,969	—
Interest and other financing costs, net	95,904	118,260	128,371
Derivatives, net	11,128	260,892	270,185
Other expenses, net	23,656	(9,054)	10,111
Total costs and expenses	1,329,800	1,962,708	1,377,219
Income (loss) before income taxes	371,735	337,067	(43,380)
Income tax expense	158,215	110,516	34,456
Net income (loss)	$ 213,520	$ 226,551	$ (77,836)
Net income (loss) per share:			
Basic	$ 0.46	$ 0.50	$ (0.19)
Diluted	$ 0.44	$ 0.48	$ (0.19)
Weighted average number of shares used to compute net income (loss) per share:			
Basic	459,641	455,346	416,943
Diluted	481,070	474,857	416,943

See accompanying notes.

KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(In thousands)

	Common Stock		Additional Paid-in	Accumulated	Treasury	
	Shares	Amount	Capital	Deficit	Stock	Total
Balance as of December 31, 2020	449,718	$ 4,497	$ 2,307,220	$ (1,634,556)	$ (237,007)	$ 440,154
Public offering of common stock	43,125	432	135,574	—	—	136,006
Dividends	—	—	227	—	—	227
Equity-based compensation	—	—	31,786	—	—	31,786
Restricted stock units	3,309	33	(33)	—	—	—
Tax withholdings on restricted stock units	—	—	(1,100)	—	—	(1,100)
Net loss	—	—	—	(77,836)	—	(77,836)
Balance as of December 31, 2021	496,152	4,962	2,473,674	(1,712,392)	(237,007)	529,237
Dividends	—	—	(39)	—	—	(39)
Equity-based compensation	—	—	34,852	—	—	34,852
Restricted stock units	4,009	40	(40)	—	—	—
Tax withholdings on restricted stock units	—	—	(2,753)	—	—	(2,753)
Net income	—	—	—	226,551	—	226,551
Balance as of December 31, 2022	500,161	5,002	2,505,694	(1,485,841)	(237,007)	787,848
Dividends	—	—	(1)	—	—	(1)
Equity-based compensation	—	—	42,780	—	—	42,780
Restricted stock units	4,232	42	(42)	—	—	—
Tax withholdings on restricted stock units	—	—	(11,810)	—	—	(11,810)
Net income	—	—	—	213,520	—	213,520
Balance as of December 31, 2023	504,393	$ 5,044	$ 2,536,621	$ (1,272,321)	$ (237,007)	$ 1,032,337

See accompanying notes.

KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31, 2023	2022	2021
Operating activities			
Net income (loss)	$ 213,520	$ 226,551	$ (77,836)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization (including deferred financing costs)	454,848	508,657	477,801
Deferred income taxes	(107,560)	(197,487)	(69,174)
Unsuccessful well costs and leasehold impairments	2,208	86,941	18,819
Impairment of long-lived assets	222,278	449,969	—
Change in fair value of derivatives	28,349	275,465	277,705
Cash settlements on derivatives, net (including $(16.4) million and $(327.9) million and $(224.4) million on commodity hedges during 2023, 2022, and 2021)	(32,426)	(344,468)	(231,767)
Equity-based compensation	42,693	34,546	31,651
Gain on sale of assets	—	(50,471)	(1,564)
Loss on extinguishment of debt	1,503	192	19,625
Other	5,709	(10,099)	(3,538)
Changes in assets and liabilities:			
(Increase) decrease in receivables	(16,223)	68,829	(34,246)
(Increase) decrease in inventories and prepaid expenses	(45,667)	(704)	637
Increase (decrease) in accounts payable and accrued liabilities	(4,062)	82,555	(33,769)
Net cash provided by operating activities	765,170	1,130,476	374,344
Investing activities			
Oil and gas assets	(932,603)	(787,297)	(472,631)
Acquisition of oil and gas properties	—	(22,078)	(465,367)
Proceeds on sale of assets	—	168,703	6,354
Notes receivable from partners	(62,247)	(63,183)	(41,733)
Net cash used in investing activities	(994,850)	(703,855)	(973,377)
Financing activities			
Borrowings under long-term debt	300,000	—	725,000
Payments on long-term debt	(145,000)	(405,000)	(1,050,000)
Net proceeds from issuance of senior notes	—	—	839,375
Net proceeds from issuance of common stock	—	—	136,006
Dividends	(166)	(655)	(512)
Other financing costs	(13,214)	(9,041)	(25,704)
Net cash provided by (used in) financing activities	141,620	(414,696)	624,165
Net increase (decrease) in cash, cash equivalents and restricted cash	(88,060)	11,925	25,132
Cash, cash equivalents and restricted cash at beginning of period	186,821	174,896	149,764
Cash, cash equivalents and restricted cash at end of period	$ 98,761	$ 186,821	$ 174,896
Supplemental cash flow information			
Cash paid for:			
Interest, net of capitalized interest	$ 74,642	$ 85,791	$ 91,032
Income taxes, net of refund received	$ 281,872	$ 247,889	$ 137,421

See accompanying notes.

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements

1. Organization

Kosmos Energy Ltd. changed our jurisdiction of incorporation from Bermuda to the State of Delaware in December 2018 as a holding company for Kosmos Energy Delaware Holdings, LLC, a Delaware limited liability company. As a holding company, Kosmos Energy Ltd.'s management operations are conducted through a wholly-owned subsidiary, Kosmos Energy, LLC. The terms "Kosmos," the "Company," "we," "us," "our," "ours," and similar terms refer to Kosmos Energy Ltd. and its wholly-owned subsidiaries, unless the context indicates otherwise.

Kosmos is a full-cycle, deepwater, independent oil and gas exploration and production company focused along the offshore Atlantic Margins. Our key assets include production offshore Ghana, Equatorial Guinea and the U.S. Gulf of Mexico, as well as world-class gas projects offshore Mauritania and Senegal. We also pursue a proven basin exploration program in Equatorial Guinea and the U.S. Gulf of Mexico. Kosmos is listed on the NYSE and LSE and is traded under the ticker symbol KOS.

Kosmos is engaged in a single line of business, which is the exploration, development, and production of oil and natural gas. Substantially all of our long-lived assets and all of our product sales are related to operations in four geographic areas: Ghana, Equatorial Guinea, Mauritania/Senegal and the U.S. Gulf of Mexico.

2. Accounting Policies

Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Kosmos Energy Ltd. and its wholly-owned subsidiaries. They also include the Company's share of the undivided interest in certain assets, liabilities, revenues and expenses.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosures of contingent assets and liabilities. These estimates could change materially if different information or assumptions were used. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results could differ from these estimates.

Reclassifications

Certain prior period amounts have been reclassified to conform with the current year presentation. Such reclassifications had no significant impact on our reported net income (loss), current assets, total assets, current liabilities, total liabilities, shareholders' equity or cash flows.

Cash, Cash Equivalents and Restricted Cash

	December 31,		
	2023	2022	2021
		(In thousands)	
Cash and cash equivalents	$ 95,345	$ 183,405	$ 131,620
Restricted cash - current	—	—	42,971
Restricted cash - long-term	3,416	3,416	305
Total cash, cash equivalents and restricted cash shown in the consolidated statements of cash flows	$ 98,761	$ 186,821	$ 174,896

Cash and cash equivalents includes demand deposits and funds invested in highly liquid instruments with original maturities of three months or less at the date of purchase. When our net leverage ratio exceeds 2.50x, we are required under the Facility to maintain a restricted cash balance that is sufficient to meet the payment of interest and fees for the next six-month period on the 7.125% Senior Notes, the 7.750% Senior Notes, and the 7.500% Senior Notes plus the Corporate Revolver or the Facility, whichever is greater. As of December 31, 2021, we exceeded this ratio and restricted approximately $42.9 million in cash to meet our requirements. As of March 31, 2022, our net leverage ratio was below 2.50x, therefore in May 2022, we released $59.1 million from restricted cash upon submission of the net leverage test as of March 31, 2022. As of December 31, 2023 and 2022 our net leverage ratio remained below 2.50x.

Receivables

Our receivables consist of joint interest billings, oil and gas sales, related party and other receivables. Receivables from joint interest owners are stated at amounts due, net of any allowances for doubtful accounts. As required by ASU 2016-13, "Measurement of Credit Losses on Financial Instruments", we determine our allowance based on historical experience, current conditions and reasonable and supportable forecasts by considering the length of time past due, future net revenues of the debtor's ownership interest in oil and natural gas properties we operate, and the owner's ability to pay its obligation, among other things. We had an allowance for doubtful accounts of $9.8 million and $7.0 million in current joint interest billings receivables as of December 31, 2023 and 2022, respectively.

Inventories

Inventories consisted of $143.0 million and $125.3 million of materials and supplies and $9.1 million and $8.2 million of hydrocarbons as of December 31, 2023 and 2022, respectively. The Company's materials and supplies inventory primarily consists of casing and wellheads and is stated at the lower of cost, using the weighted average cost method, or net realizable value. We recorded write downs of $7.4 million, $1.5 million and $1.2 million during the years ended December 31, 2023, 2022 and 2021 for materials and supplies inventories as Other expenses, net in the consolidated statements of operations and other in the consolidated statements of cash flows.

Hydrocarbon inventory is carried at the lower of cost, using the weighted average cost method, or net realizable value. Hydrocarbon inventory costs include expenditures and other charges incurred in bringing the inventory to its existing condition. Selling expenses and general and administrative expenses are reported as period costs and excluded from inventory costs.

Leases

We account for leases in accordance with ASC Topic 842, Leases, ("ASC 842"). We determine if an arrangement is a lease at contract inception. In the normal course of business, the Company enters into various lease agreements for real estate and equipment related to its exploration, development and production activities that are currently accounted for as operating leases. Operating leases are included in Other assets, Accrued liabilities, and Other long-term liabilities on our consolidated balance sheets. The lease liabilities are initially and subsequently measured at the present value of the unpaid lease payments at the lease commencement date. We monitor for events or changes in circumstances that require a reassessment of a lease. When a reassessment results in the re-measurement of a lease liability, a corresponding adjustment is made to the carrying amount of the corresponding ROU asset unless doing so would reduce the carrying amount of the ROU asset to an amount less than zero. In that case, the amount of the adjustment that would result in a negative ROU asset balance is recorded in profit or loss.

Exploration and Development Costs

The Company follows the successful efforts method of accounting for its oil and gas properties. Acquisition costs for proved and unproved properties are capitalized when incurred. Costs of unproved properties are transferred to proved properties when a determination that proved reserves have been found. Exploration costs, including geological and geophysical costs and costs of carrying unproved properties, are expensed as incurred. Exploratory drilling costs are capitalized when incurred. If exploratory wells are determined to be commercially unsuccessful or dry holes, the applicable costs are expensed and recorded in exploration expense on the consolidated statement of operations. Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized. Costs incurred to operate and maintain wells and equipment and to lift oil and natural gas to the surface are expensed as oil and gas production expense.

The Company evaluates unproved property periodically for impairment. The impairment assessment considers results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects. If it is determined that future appraisal drilling or development activities are unlikely to occur, the associated capitalized costs are recorded as exploration expense in the consolidated statement of operations.

Depletion, Depreciation and Amortization

Proved properties and support equipment and facilities are depleted using the unit-of-production method based on estimated proved oil and natural gas reserves. Capitalized exploratory drilling costs that result in a discovery of proved reserves and development costs are depleted using the unit-of-production method based on estimated proved developed oil and natural gas reserves for the related field.

Depreciation and amortization of other property is computed using the straight-line method over the assets' estimated useful lives (not to exceed the lease term for leasehold improvements), ranging from one to eight years.

	Years Depreciated
Leasehold improvements	1 to 8
Office furniture, fixtures and computer equipment	3 to 7

Amortization of deferred financing costs is computed using the straight-line method over the life of the related debt.

Capitalized Interest

Interest costs from external borrowings are capitalized on major projects with an expected construction period of one year or longer. Capitalized interest is added to the cost of the underlying asset and is depleted on the unit-of-production method in the same manner as the underlying assets.

Asset Retirement Obligations

The Company accounts for asset retirement obligations as required by ASC 410—Asset Retirement and Environmental Obligations. Under these standards, the fair value of a liability for an asset retirement obligation is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. If a reasonable estimate of fair value cannot be made in the period the asset retirement obligation is incurred, the liability is recognized when a reasonable estimate of fair value can be made. If a tangible long-lived asset with an existing asset retirement obligation is acquired, a liability for that obligation is recognized at the asset's acquisition or in service date. In addition, a liability for the fair value of a conditional asset retirement obligation is recorded if the fair value of the liability can be reasonably estimated. We capitalize the asset retirement costs by increasing the carrying amount of the related long-lived asset by the same amount as the liability. We record increases in the discounted abandonment liability resulting from the passage of time in depletion, depreciation and amortization in the consolidated statement of operations. Estimating the future restoration and removal costs requires management to make estimates and judgments because most of the removal obligations are many years in the future and the regulations in some countries that we operate often have vague descriptions of what constitutes removal. Additionally, asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

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. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligations, a corresponding adjustment is made to the oil and gas property balance.

Acquisition Accounting

The purchase price in an acquisition (business combination or asset acquisition) is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the deal announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired, and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. The most significant estimates in the allocation typically relate to the value assigned to future recoverable oil and natural gas reserves and unproved properties. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain.

Impairment of Long-lived Assets

We review our long-lived assets for impairment when changes in circumstances indicate that the carrying amount of an asset may not be recoverable. ASC 360 — Property, Plant and Equipment requires an impairment loss to be recognized if the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. The carrying amount of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. That assessment shall be based on the carrying amount of the asset at the date it is tested for recoverability, whether in use or under development. Assets to be disposed of and assets not expected to provide any future service potential to us are recorded at the lower of carrying amount or fair value. Oil and gas properties are grouped in accordance with ASC 932 — Extractive Activities-Oil and Gas. The basis for grouping is a reasonable aggregation of properties typically by field or by logical grouping of assets with significant shared infrastructure.

For long-lived assets whereby the carrying value exceeds the estimated future undiscounted cash flows, the carrying amount is reduced to fair value. Fair value is generally estimated using the income approach described in the ASC 820 — Fair Value Measurement. If applicable, we utilize prices and other relevant information generated by market transactions involving assets and liabilities that are identical or comparable to the item being measured as the basis for determining fair value. The expected future cash flows used for impairment reviews and related fair value measurements are typically based on judgmental assessments of future production, pricing estimates, capital and operating costs, market-based weighted average cost of capital, and risk adjustment factors applied to reserves. These assumptions are applied to develop future cash flow projections that are then discounted to estimated fair value, using a market-based weighted-average cost of capital.

We believe the assumptions used in our analysis to test for impairment are appropriate and result in a reasonable estimate of future cash flows and fair value. Kosmos has consistently used an average of third-party industry forecasts to determine our pricing assumptions. Where unproved reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the evaluation.

Derivative Instruments and Hedging Activities

We utilize oil derivative contracts to mitigate our exposure to commodity price risk associated with our anticipated future oil production. These derivative contracts consist of collars, put options, call options and swaps. Our derivative financial instruments are recorded on the balance sheet as either assets or liabilities and are measured at fair value. We do not apply hedge accounting to our derivative contracts. See Note 9—Derivative Financial Instruments.

Estimates of Proved Oil and Natural Gas Reserves

Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion and assessment of impairment of our oil and natural gas properties. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. As additional proved reserves are discovered, reserve quantities and future cash flows will be estimated by independent petroleum consultants and prepared in accordance with guidelines established by the SEC and the FASB. The accuracy of these reserve estimates is a function of:

- the engineering and geological interpretation of available data;
- estimates of the amount and timing of future operating cost, production taxes, development cost and workover cost;
- the accuracy of various mandated economic assumptions; and
- the judgments of the persons preparing the estimates.

Revenue Recognition

We recognize revenues on the volumes of hydrocarbons sold to a purchaser. The volumes sold may be more or less than the volumes to which we are entitled based on our ownership interest in the property. These differences result in a condition known in the industry as a production imbalance. A receivable or liability is recognized only to the extent that we have an imbalance on a specific property greater than the expected remaining proved reserves on such property. As of December 31, 2023 and 2022, we had no oil and gas imbalances recorded in our consolidated financial statements.

Our oil and gas revenues are recognized when hydrocarbons have been sold to a purchaser at a fixed or determinable price, title has transferred and collection is probable. Certain revenues are based on contracts with provisional pricing and quantity optionality which contain a derivative that is required to be separated from the host contract for accounting purposes. The host contract is the receivable from oil sales at the spot price on the date of sale. The derivative, which is not designated as a hedge, is marked to market through oil and gas revenue each period until the final settlement occurs, which generally is limited to the month of or month after the sale.

Oil and gas revenue is composed of the following:

	Years Ended December 31,		
	2023	2022	2021
	(In thousands)		
Revenues from contracts with customers:			
Equatorial Guinea	$ 273,280	$ 349,443	$ 257,628
Ghana	1,073,917	1,362,875	654,644
U.S. Gulf of Mexico	371,632	547,610	427,261
Total revenues from contracts with customers	1,718,829	2,259,928	1,339,533
Provisional oil sales contracts	(17,221)	(14,573)	(7,520)
Oil and gas revenue	$ 1,701,608	$ 2,245,355	$ 1,332,013

Equity-based Compensation

For equity-based compensation awards, compensation expense is recognized in the Company’s financial statements over the awards’ vesting periods based on their grant date fair value. The Company utilizes (i) the closing stock price on the date of grant to determine the fair value of service vesting restricted stock units and (ii) a Monte Carlo simulation to determine the fair value of restricted stock units with a combination of market and service vesting criteria. Forfeitures are recognized in the period in which they occur.

Income Taxes

The Company accounts for income taxes as required by ASC 740—Income Taxes. Under this method, deferred income taxes are determined based on the difference between the financial statement and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse. Valuation allowances are established when necessary to reduce deferred tax assets to the amounts expected to be realized. On a quarterly basis, management evaluates the need for and adequacy of valuation allowances based on the expected realizability of the deferred tax assets and adjusts the amount of such allowances, if necessary.

We recognize tax benefits from uncertain tax positions only if it is more likely than not that the tax position will be sustained upon examination by the tax authorities, based on the technical merits of the position. Accordingly, we measure tax benefits from such positions based on the most likely outcome to be realized.

Foreign Currency Translation

The U.S. dollar is the functional currency for all of the Company’s material foreign operations. Foreign currency transaction gains and losses and adjustments resulting from translating monetary assets and liabilities denominated in foreign currencies are included in other expenses. Cash balances held in foreign currencies are not significant, and as such, the effect of exchange rate changes is not material to any reporting period.

Concentration of Credit Risk

Our revenue can be materially affected by current economic conditions and the price of oil and natural gas. However, based on the current demand for crude oil and natural gas and the fact that alternative purchasers are readily available, we believe that the loss of our marketing agents and/or any of the purchasers identified by our marketing agents would not have a long-term material adverse effect on our financial position or results of international operations. The continued economic disruption resulting from Russia's war in Ukraine, potential instability in the Middle East, a potential global recession, inflationary pressures and other varying macroeconomic conditions could materially impact the Company's business in future periods. Any potential disruption will depend on the duration and intensity of these events, which are highly uncertain and cannot be predicted at this time.

Recent Accounting Standards

Not Yet Adopted

In December 2023, the FASB issued ASU 2023-09, "Improvements to Income Tax Disclosures (Topic 740)." The amendments focus on income tax disclosures around effective tax rates and cash income taxes paid. The amendments in the ASU are effective for annual periods beginning after December 15, 2024. Early adoption is permitted, however, we do not plan to early adopt ASU 2023-09.

3. Acquisitions and Divestitures

2023 Transactions

In February 2023, Kosmos entered into a petroleum contract covering Block EG-01 offshore Equatorial Guinea with the Republic of Equatorial Guinea. Kosmos holds a 24% non-operated participating interest in the block. Block EG-01 currently comprises approximately 59,400 acres (240 square kilometers), with a first exploration period of three years from the effective date (March 1, 2023).

In November 2023, BP decided not to participate in the future development and exploitation of the Yakaar and Teranga discoveries. In accordance with the provisions of the Contract for Exploration and Production Sharing of Hydrocarbons for the Cayar Offshore Profond Block (the "Contract") and the related Joint Operating Agreement (the "JOA"), BP has waived its rights in respect of the Yakaar and Teranga discoveries. As provided in the JOA, Kosmos has assumed BP's participating interest under the Contract and the JOA and has become operator of the Cayar Offshore Profond Block, with customary government approvals having been received effective January 18, 2024. The participating interests in the Cayar Offshore Profond Block are now: Kosmos 90% and PETROSEN 10%, with PETROSEN having the right to increase its participating interest after issuance of an exploitation authorization to up to 35%.

2022 Transactions

In March 2022, Kosmos completed the acquisition of an additional 5.5% interest in Winterfell area in Green Canyon Blocks 943, 944, 987 and 988, offshore U.S. Gulf of Mexico, and an additional 1.5% interest in Green Canyon blocks 899 and 900 for $9.6 million. Additionally, in September 2022, Kosmos completed the acquisition of an additional 3.2% interest in the Winterfell area in Green Canyon Blocks 943, 944, 987 and 988 and an additional 1.4% interest in Green Canyon Blocks 899 and 900 for $6.6 million. As a result of the two transactions, our participating interests in the Green Canyon Blocks 943, 944, 987 and 988 is now 25.0% and our participating interests in the Green Canyon Blocks 899 and 900 is 37.8%.

In May 2022, Kosmos and its joint venture partners agreed with the Ministry of Mines and Hydrocarbons of Equatorial Guinea to extend the Block G petroleum contract term harmonizing the expiration of the Ceiba Field and Okume Complex production licenses (from 2029 and 2034 respectively) to 2040. As part of the extension, during the second quarter of 2022, Kosmos paid a signature bonus and agreed to undertake a work program including the drilling of three development wells on Block G in either the Ceiba Field or Okume Complex and the drilling of one exploration well in Block S offshore Equatorial Guinea.

In June 2022, Kosmos completed the acquisition of an additional 5.9% interest in the Kodiak oil field from Marubeni by exercising our preferential right to purchase for a total purchase price of approximately $29.0 million. The purchase price was based on an initial purchase price of $38.3 million reduced by certain purchase adjustments totaling approximately $9.3 million. The purchase price allocation was based on the estimated fair value of identifiable assets acquired and liabilities assumed primarily comprised of $27.1 million of oil and gas properties, net. As a result of the transaction, our working interest increased from 29.1% to 35.0%.

In June 2022, at the conclusion of the second exploration period, Block C12 offshore Mauritania was relinquished.

In October 2022, we entered into a farm-out agreement with Panoro Energy ASA (Panoro) to farm-out a 6.0% participating interest in Block S offshore Equatorial Guinea, which reduced our participating interest in Block S to 34.0%, in exchange for cash consideration totaling approximately $1.8 million. In March 2023, the transaction was approved by the Government of Equatorial Guinea and the farm-out agreement was closed.

2021 Transactions

In October 2021, Kosmos completed the acquisition of Anadarko WCTP Company ("Anadarko WCTP"), a subsidiary of Occidental Petroleum Corporation, which owns a participating interest in the WCTP Block and DT Block offshore Ghana, including an 18.0% participating interest in the Jubilee Unit Area and an 11.1% participating interest in the TEN Fields. In consideration for the acquisition, Kosmos paid $455.9 million in cash based on an initial purchase price of $550.6 million reduced by certain purchase price adjustments totaling $94.7 million. Additionally, we incurred $9.5 million of transaction related costs, which were capitalized as part of the purchase price. Following closing of the acquisition, Kosmos' interest in the Jubilee Unit Area increased from 24.1% to 42.1%, and Kosmos' interest in the TEN Fields increased from 17.0% to 28.1%.

Kosmos initially funded the purchase price through the issuance of $400.0 million aggregate principal amount of floating rate senior notes due 2022 ("Bridge Notes") and $75.0 million of borrowings under Kosmos' Facility. Kosmos then refinanced the Bridge Notes in full with the proceeds from the issuance of $400.0 million of 7.750% Senior Notes due 2027 and cash on hand. Kosmos also received $136.6 million in proceeds from a public issuance of 43.1 million shares of Kosmos' common stock with proceeds used to repay a portion of outstanding borrowings under the Facility during the fourth quarter of 2021. The purchase price allocation was based on the estimated fair value of identifiable assets acquired and liabilities assumed.

	Purchase Price Allocation (in thousands)	
Fair value of assets acquired:		
Proved oil and gas properties	$	718,159
Accounts receivable and other		95,847
Total assets acquired	$	814,006
Fair value of liabilities assumed:		
Asset retirement obligations	$	28,342
Accounts payable and accrued liabilities		113,704
Deferred tax liabilities		206,593
Total liabilities assumed	$	348,639
Purchase price:		
Cash consideration paid	$	455,886
Transaction related costs		9,481
Total purchase price	$	465,367

As a result of the acquisition of Anadarko WCTP, $104.4 million of revenues and $10.3 million of direct operating expenses have been included in our consolidated statements of operations for the period from October 13, 2021 to December 31, 2021.

Under the DT Block Joint Operating Agreement, certain joint venture partners have pre-emption rights in the Jubilee Unit Area and the TEN Fields. In November 2021, we received notice from Tullow Oil plc ("Tullow") that they were exercising their pre-emption rights in relation to Kosmos' acquisition of Anadarko WCTP. After execution of definitive transaction documentation and receipt of government approvals, Kosmos concluded the pre-emption transaction with Tullow in

March 2022. Following the completion of the pre-emption process, Kosmos' interest in the Jubilee Unit Area decreased from 42.1% to 38.6% and Kosmos' interest in the TEN Fields decreased from 28.1% to 20.4%. Tullow paid Kosmos $118.2 million in cash consideration after post closing adjustments for the pre-emption. During the first quarter of 2022, our oil and gas properties, net balance was reduced by $175.5 million, which includes the cash proceeds and net liabilities transferred to the purchaser as a result of concluding the Tullow pre-emption transaction. The difference in the net book value of the proved property, net liabilities transferred and adjusted purchase price qualified for treatment as a recovery of cost and normal retirement under ASC 932, which resulted in no gain or loss being recognized.

In 2021, at the conclusion of the second exploration period, Block C13 offshore Mauritania was relinquished.

4. Receivables

Receivables consisted of the following:

	December 31,	
	2023	2022
	(In thousands)	
Joint interest billings, net	35,632	28,851
Oil sales	64,958	67,483
Other current receivables	20,143	23,401
Total receivables	120,733	119,735
Long-term receivables	325,181	235,696

The Company's joint interest billings consist of receivables from partners with interests in common oil and gas properties operated by the Company for shared costs. Joint interest billings are classified as current and long-term receivables based on when collection is expected to occur.

Long-term receivables

In February 2019, Kosmos and BP signed Carry Advance Agreements with the national oil companies of Mauritania and Senegal obligating us to finance a portion of the respective national oil companies' share of certain development costs incurred through first gas production for Greater Tortue Ahmeyim Phase 1. The amount financed by Kosmos is to be repaid with interest through the national oil companies' share of future revenues. As of December 31, 2023 and 2022, the principal balance due from the national oil companies was $259.2 million and $196.9 million, respectively, which is classified as Long-term receivables in our consolidated balance sheets. As of December 31, 2023 and 2022, accrued interest on the balance due from the national oil companies was $37.3 million and $21.5 million, respectively, which is classified as Long-term receivables in our consolidated balance sheets. Interest income on the long-term notes receivable was $15.9 million, $10.1 million and $7.1 million for the years ended December 31, 2023, 2022 and 2021, respectively.

In August 2021, BP, as the operator of the Greater Tortue project ("BP Operator"), with the consent of the Greater Tortue Unit participants and the respective States, agreed to sell the Greater Tortue FPSO (which is currently under construction by Technip Energies) to an affiliate of BP ("BP Buyer"). The Greater Tortue FPSO will be leased back to BP Operator under a long-term lease agreement, for exclusive use in the Greater Tortue project. BP Operator will continue to manage and supervise the construction contract with Technip Energies. Delivery of the Greater Tortue FPSO to BP Buyer will occur after construction is complete and the Greater Tortue FPSO has been commissioned, with the lease to BP Operator becoming effective on the same date, currently targeted to be in the third quarter of 2024.

As a result of the above transactions entered into by BP Operator, Kosmos recognized a Long-term receivable of $200.2 million from BP Operator for our share of the consideration paid from BP Buyer to and held by BP Operator as well as a $200.2 million FPSO Contract Liability in Other long-term liabilities related to the deferred sale of the Greater Tortue FPSO. As of December 31, 2022, this Long-term receivable has been non-cash settled against obligations payable to BP Operator, which included $132.4 million and $67.8 million of non-cash capital expenditures during the fourth quarter of 2021 and the first quarter of 2022, respectively. These non-cash impacts are excluded from the statement of cash flows.

In Ghana, the foreign contractor group funded GNPC’s 5% share of TEN development costs. The foreign contractor group is being reimbursed for such costs plus interest out of a portion of GNPC’s TEN production revenues. As of December 31, 2023 and 2022, the long-term portions of joint interest billing receivables due from GNPC for the TEN Fields’ development costs were $28.7 million and $17.3 million.

5. Property and Equipment

Property and equipment is stated at cost and consisted of the following:

	December 31,	
	2023	2022
	(In thousands)	
Oil and gas properties:		
Proved properties	$ 7,600,252	$ 6,953,435
Unproved properties	423,050	341,334
Total oil and gas properties	8,023,302	7,294,769
Accumulated depletion	(3,868,946)	(3,457,332)
Oil and gas properties, net	4,154,356	3,837,437
Other property	65,095	60,730
Accumulated depreciation	(59,222)	(55,520)
Other property, net	5,873	5,210
Property and equipment, net	$ 4,160,229	$ 3,842,647

We recorded depletion expense of $411.6 million, $471.4 million and $442.3 million and depreciation expense of $3.7 million, $3.6 million and $3.9 million for the years ended December 31, 2023, 2022 and 2021, respectively. In connection with fair value assessments for oil and gas proved properties, we recorded asset impairments of $222.3 million and 450.0 million related to the TEN Fields in Ghana during the years ended December 31, 2023 and 2022, respectively in our consolidated statement of operations. No asset impairment was recorded for the year ended December 31, 2021. During the year ended December 31, 2023, additions to our unproved properties primarily related to the Winterfell development project and the drilling of the Tiberius infrastructure-led exploration prospect. Additions to our proved properties for the year ended December 31, 2023 primarily related to continued infill development in the Jubilee Field in Ghana including the successful startup of the Jubilee Southeast project with the installation of a new subsea production manifold, the Odd Job Field subsea pump installation in the U.S. Gulf of Mexico and continued progress on the development of the Greater Tortue Ahmeyim project in Mauritania/Senegal.

During the year ended December 31, 2022, our oil and gas properties, net balance was reduced by $175.5 million as a result of concluding the Tullow pre-emption transaction in March 2022, $64.2 million as a result of the write-off of previously capitalized costs related to the BirAllah and Orca discoveries incurred under the C8 license to exploration expense, offset by additions of $53.1 million related to the acquisition of an additional working interest in the Kodiak oil field, the extension of the Block G licenses in Equatorial Guinea, and the acquisitions of additional participating interests in the Winterfell area. See Note 3 — Acquisitions and Divestitures and Note 6 — Suspended Well Costs.

6. Suspended Well Costs

The Company capitalizes exploratory well costs as unproved properties within oil and gas properties until a determination is made that the well has either found proved reserves or is impaired. If proved reserves are found, the capitalized exploratory well costs are reclassified to proved properties. Well costs are charged to exploration expense if the exploratory well is determined to be impaired.

The following table reflects the Company’s capitalized exploratory well costs on drilled wells as of and during the years ended December 31, 2023, 2022 and 2021.

	Years Ended December 31,		
	2023	2022	2021
	(In thousands)		
Beginning balance	$ 145,957	$ 218,180	$ 186,289
Additions to capitalized exploratory well costs pending the determination of proved reserves	66,002	25,209	31,891
Reclassification due to determination of proved reserves(1)	—	(34,614)	—
Capitalized exploratory well costs charged to expense(2)	—	(62,818)	—
Ending balance	$ 211,959	$ 145,957	$ 218,180

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(1) Activity for the year ended December 31, 2022 represents the reclassification of exploratory well costs associated with the Winterfell discovery in Green Canyon Block 944 in the U.S. Gulf of Mexico.

(2) Represents the impairment of exploratory well costs associated with the BirAllah and Orca Discoveries as a result of the expiration of the exploration period of Block C8 in June 2022.

The following table provides aging of capitalized exploratory well costs based on the date drilling was completed and the number of projects for which exploratory well costs have been capitalized for more than one year since the completion of drilling:

	Years Ended December 31,		
	2023	2022	2021
	(In thousands, except well counts)		
Exploratory well costs capitalized for a period of one year or less	$ 54,274	$ —	$ 20,903
Exploratory well costs capitalized for a period of one to three years	—	32,770	30,389
Exploratory well costs capitalized for a period of four to seven years	157,685	113,187	166,888
Ending balance	$ 211,959	$ 145,957	$ 218,180
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	2	2	3

As of December 31, 2023, the projects with exploratory well costs capitalized for more than one year since the completion of drilling are related to the Yakaar and Teranga discoveries in the Cayar Offshore Profond block offshore Senegal and the Asam discovery in Block S offshore Equatorial Guinea.

Yakaar and Teranga Discoveries — In May 2016, we drilled the Teranga-1 exploration well in the Cayar Offshore Profond Block offshore Senegal, which encountered hydrocarbon pay. In June 2017, we drilled the Yakaar-1 exploration well in the Cayar Offshore Profond Block offshore Senegal, which encountered hydrocarbon pay. In November 2017, an integrated Yakaar-Teranga appraisal plan was submitted to the Government of Senegal. In September 2019, we drilled the Yakaar-2 appraisal well which encountered hydrocarbon pay. The Yakaar-2 well was drilled approximately nine kilometers from the Yakaar-1 exploration well. In July 2021, the current phase of the Cayar Block exploration license was extended up to an additional three years to 2024. The Yakaar and Teranga discoveries are being analyzed as a joint development. During 2023, we continued progressing appraisal studies and maturing concept design. Following additional evaluation and further concept design development, a decision regarding commerciality is expected to be made.

Asam Discovery - In October 2019, we drilled the S-5 exploration well offshore Equatorial Guinea, which encountered hydrocarbon pay. The discovery was subsequently named Asam. In July 2020, an appraisal work program was approved by the Government of Equatorial Guinea. The well is located within tieback range of the Ceiba FPSO and the appraisal work program is currently ongoing to integrate all available data into models to establish the scale of the discovered resource and evaluate the optimum development solution. During the fourth quarter of 2022, we received approval from the Government of Equatorial Guinea to enter the second sub-period phase of the Block S exploration license with a scheduled expiration in December 2024. Additionally, in December 2022 the Asam Field appraisal report was submitted to the Government of Equatorial Guinea. During 2023, studies and concept design continued to progress. Following additional evaluation, a decision regarding commerciality will be made.

7. Leases

We have commitments under operating leases primarily related to office leases. Our leases have initial lease terms ranging from one year to ten years. Certain lease agreements contain provisions for future rent increases.

The components of lease cost for the years ended December 31, 2023 and 2022 is as follows:

	December 31,	
	2023	2022
	(In thousands)	
Operating lease cost	$ 3,866	$ 3,882
Variable lease cost	1,766	1,825
Short-term lease cost(1)	17,464	13,970
Total lease cost	$ 23,096	$ 19,677

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(1) Includes $16.0 million and $12.5 million during the years ended December 31, 2023 and 2022, respectively, of costs associated with short-term drilling contracts.

Other information related to operating leases at December 31, 2023 and 2022, is as follows:

	December 31	
	2023	2022
	(In thousands, except lease term and discount rate)	
Balance sheet classifications		
Other assets (right-of-use assets)	$ 14,234	$ 16,044
Accrued liabilities (current maturities of leases)	2,492	2,181
Other long-term liabilities (non-current maturities of leases)	15,576	18,007
Weighted average remaining lease term	5.6 years	6.5 years
Weighted average discount rate	9.8 %	9.8 %

The table below presents supplemental cash flow information related to leases during the years ended December 31, 2023 and 2022:

	December 31,	
	2023	2022
	(In thousands)	
Operating cash flows for operating leases	$ 7,256	$ 7,170
Investing cash flows for operating leases(1)	16,029	12,449

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(1) Represents costs associated with short-term drilling contracts.

Future minimum rental commitments under our leases at December 31, 2023, are as follows:

	Operating Leases(1)
	(In thousands)
2024	$ 4,124
2025	4,195
2026	4,266
2027	4,205
2028	3,844
Thereafter	2,808
Total undiscounted lease payments	$ 23,442
Less: Imputed interest	(5,374)
Total lease liabilities	$ 18,068

(1) Does not include purchase commitments for jointly owned fields and facilities where we are not the operator and excludes commitments for exploration activities, including well commitments, in our petroleum contracts.

8. Debt

	December 31,	
	2023	2022
	(In thousands)	
Outstanding debt principal balances:		
Facility	$ 925,000	$ 625,000
Corporate Revolver	—	—
7.125% Senior Notes	650,000	650,000
7.750% Senior Notes	400,000	400,000
7.500% Senior Notes	450,000	450,000
GoM Term Loan	—	145,000
Total long-term debt	2,425,000	2,270,000
Unamortized deferred financing costs and discounts(1)	(34,086)	(44,089)
Total debt, net	2,390,914	2,225,911
Less: Current maturities of long-term debt	—	(30,000)
Long-term debt, net	$ 2,390,914	$ 2,195,911

(1) Includes $20.8 million and $25.2 million of unamortized deferred financing costs related to the Facility and $13.3 million and $16.7 million of unamortized deferred financing costs and discounts related to the Senior Notes as of December 31, 2023 and December 31, 2022, respectively.

Facility

The Facility supports our oil and gas exploration, appraisal and development programs and corporate activities. The amount of funds available to be borrowed under the Facility, also known as the borrowing base amount, is determined every March and September. The borrowing base amount is based on the sum of the net present values of net cash flows and relevant capital expenditures reduced by certain percentages as well as value attributable to certain assets' reserves and/or resources in the Jubilee and TEN Fields in Ghana and the Ceiba Field and Okume Complex in Equatorial Guinea.

In May 2021, the Company entered into an amended and restated facility agreement and certain ancillary documents. As part of this amendment to the Facility in May 2021, the Company incurred $15.2 million for loss on extinguishment of debt during the year ended December 31, 2021. On November 23, 2022, the Company amended the Facility to update the interest rate benchmark from LIBOR to term SOFR, to be effective as of April 19, 2023. On September 29, 2023, the Company amended the Facility to accede Kosmos Energy Ghana Investments and Kosmos Energy Ghana Holdings Limited to the Facility as obligors. As a result, the additional interests in Jubilee and TEN that were acquired in the October 2021 acquisition of Anadarko WCTP are now included when calculating the borrowing base amount for the Facility, effective October 1, 2023. On October 19, 2023, the Company amended the Facility to modify the amortization schedule in order to reduce the number of repayment installments from seven to six equal installments, with the first repayment installment scheduled on October 1, 2024, subject to the outstanding borrowings, rather than March 31, 2024. There was no change to the final maturity date or final repayment date.

In October 2023, during the Fall 2023 redetermination, the Company's lending syndicate approved a borrowing base of $1.25 billion. As of December 31, 2023, the undrawn availability under the facility was $325.0 million.

When our net leverage ratio exceeds 2.50x, we are required under the Facility to maintain a restricted cash balance that is sufficient to meet the payment of interest and fees for the next six-month period on the 7.125% Senior Notes, the 7.750% Senior Notes and the 7.500% Senior Notes plus the Corporate Revolver or the Facility, whichever is greater. As of December 31, 2021, we exceeded this ratio and restricted approximately $42.9 million in cash to meet our requirements. As of March 31, 2022, our net leverage ratio was below 2.50x, and therefore, we released $59.1 million from restricted cash in May 2022 upon submission of the net leverage test as of March 31, 2022. As of December 31, 2023 and 2022 our net leverage ratio remained below 2.50x.

Interest on the Facility is the aggregate of the applicable margin (3.75% to 5.00%, depending on the length of time that has passed from the date the Facility was entered into), plus the term SOFR reference rate administered by CME Group Benchmark Administration Limited for the relevant period published and a credit adjustment spread. Interest is payable on the last day of each interest period (and, if the interest period is longer than six months, on the dates falling at six-month intervals after the first day of the interest period). We pay commitment fees on the undrawn and unavailable portion of the total commitments, if any. Commitment fees are equal to 30% per annum of the then-applicable respective margin when a commitment is available for utilization and, equal to 20% per annum of the then-applicable respective margin when a commitment is not available for utilization. We recognize interest expense in accordance with ASC 835—Interest, which requires interest expense to be recognized using the effective interest method. We determined the effective interest rate based on the estimated level of borrowings under the Facility.

The Facility provides a revolving credit and letter of credit facility. The availability period for the revolving credit facility expires one month prior to the final maturity date. The letter of credit facility expires on the final maturity date. The available facility amount is subject to borrowing base constraints and, beginning on October 1, 2024, outstanding borrowings will be constrained by an amortization schedule. The Facility has a final maturity date of March 31, 2027. As of December 31, 2023, we had no letters of credit issued under the Facility. We have the right to cancel all the undrawn commitments under the amended and restated Facility.

If an event of default exists under the Facility, the lenders can accelerate the maturity and exercise other rights and remedies, including the enforcement of security granted pursuant to the Facility over certain assets held by our subsidiaries. We were in compliance with the financial covenants below contained in the Facility as of September 30, 2023 (the most recent assessment date), which requires the maintenance of:

- the field life cover ratio (as defined in the glossary), not less than 1.30x; and
- the loan life cover ratio (as defined in the glossary), not less than 1.10x through March 31, 2024 and 1.30x after March 31, 2024; and
- the interest cover ratio (as defined in the glossary), not less than 2.25x; and
- the debt cover ratio (as defined in the glossary), not more than 3.50x as amended.

The Facility contains customary cross default provisions.

Corporate Revolver

On March 31, 2022, we refinanced the Corporate Revolver by replacing it with a new revolving credit facility agreement with a total size of $250 million and a maturity date of December 31, 2024. The Company capitalized $6.1 million of deferred financing costs associated with entering into the new revolving credit facility in March 2022, which is being amortized over the term of the new revolving credit facility. On November 23, 2022, the Company amended the Corporate Revolver to update the interest rate benchmark from compounded SOFR to term SOFR, effective April 2023. As amended, interest on the Corporate Revolver is the aggregate of a 7.0% margin, the term SOFR reference rate administered by CME Group Benchmark Administration Limited for the relevant period published and a credit adjustment spread. Interest is payable on the last day of each interest period (and, if the interest period is longer than six months, on the dates falling at six-month intervals after the first day of the interest period). We pay commitment fees on the undrawn portion of the total commitments. Commitment fees for the lenders are equal to 30% per annum of the respective margin when a commitment is available for utilization.

As of December 31, 2023, the undrawn availability was $250.0 million. The Corporate Revolver is available for general corporate purposes and for oil and gas exploration, appraisal and development programs.

The Corporate Revolver expires on December 31, 2024. The available amount is not subject to borrowing base constraints. We have the right to cancel all the undrawn commitments under the Corporate Revolver. We are required to repay certain amounts due under the Corporate Revolver with sales of certain subsidiaries or sales of certain assets. If an event of default exists under the Corporate Revolver, the lenders can accelerate the maturity and exercise other rights and remedies, including the enforcement of security granted pursuant to the Corporate Revolver over certain assets held by us.

We were in compliance with the financial covenants below contained in the Corporate Revolver as of September 30, 2023 (the most recent assessment date), which requires the maintenance of:

- the interest cover ratio (as defined in the glossary), not less than 2.25x; and
- the debt cover ratio (as defined in the glossary), not more than 3.50x as amended.

The Corporate Revolver contains customary cross default provisions.

7.125% Senior Notes due 2026

In April 2019, the Company issued $650.0 million of 7.125% Senior Notes and received net proceeds of approximately $640.0 million after deducting commissions and other expenses. We used the net proceeds to redeem all of the previously issued 7.875% Senior Secured Notes due 2021, repay a portion of the outstanding indebtedness under the Corporate Revolver and pay fees and expenses related to the redemption, repayment and the issuance of the 7.125% Senior Notes.

The 7.125% Senior Notes mature on April 4, 2026. We will pay interest in arrears on the 7.125% Senior Notes each April 4 and October 4, commencing on October 4, 2019. The 7.125% Senior Notes are senior, unsecured obligations of Kosmos Energy Ltd. and rank equal in right of payment with all of its existing and future senior indebtedness (including all borrowings under the Corporate Revolver, the 7.750% Senior Notes and the 7.500% Senior Notes) and rank effectively junior in right of payment to all of its existing and future secured indebtedness (including all borrowings under the Facility). The 7.125% Senior Notes are guaranteed on a senior, unsecured basis by certain subsidiaries owning the Company's U.S. Gulf of Mexico assets, and on a subordinated, unsecured basis by certain subsidiaries that borrow under, or guarantee, the Facility and that guarantee the Corporate Revolver, the 7.750% Senior Notes and the 7.500% Senior Notes. The 7.125% Senior Notes contain customary cross default provisions.

On or after April 4, 2022, the Company may redeem all or a part of the 7.125% Senior Notes at the redemption prices (expressed as percentages of principal amount) set forth below plus accrued and unpaid interest:

Year	Percentage
On or after April 4, 2022	103.563 %
On or after April 4, 2023	101.781 %
On or after April 4, 2024	100.000 %

We may also redeem the 7.125% Senior Notes in whole, but not in part, at any time if changes in tax laws impose certain withholding taxes on amounts payable on the 7.125% Senior Notes at a price equal to the principal amount of the 7.125% Senior Notes plus accrued interest and additional amounts, if any, as may be necessary so that the net amount received by each holder after any withholding or deduction on payments of the 7.125% Senior Notes will not be less than the amount such holder would have received if such taxes had not been withheld or deducted.

Upon the occurrence of a change of control triggering event as defined under the 7.125% Senior Notes indenture, the Company will be required to make an offer to repurchase the 7.125% Senior Notes at a repurchase price equal to 101% of the principal amount, plus accrued and unpaid interest to, but excluding, the date of repurchase.

If we sell assets, under certain circumstances outlined in the 7.125% Senior Notes indenture, we will be required to use the net proceeds to make an offer to purchase the 7.125% Senior Notes at an offer price in cash in an amount equal to 100% of the principal amount of the 7.125% Senior Notes, plus accrued and unpaid interest to, but excluding, the repurchase date.

The 7.125% Senior Notes indenture restricts the ability of the Company and its restricted subsidiaries to, among other things: incur or guarantee additional indebtedness, create liens, pay dividends or make distributions in respect of capital stock, purchase or redeem capital stock, make investments or certain other restricted payments, sell assets, enter into agreements that restrict the ability of the Company's subsidiaries to make dividends or other payments to the Company, enter into transactions with affiliates, or effect certain consolidations, mergers or amalgamations. These covenants are subject to a number of important qualifications and exceptions. Certain of these covenants will be terminated if the 7.125% Senior Notes are assigned an investment grade rating by both Standard & Poor's Rating Services and Fitch Ratings Inc. and no default or event of default has occurred and is continuing. The 7.125% Senior Notes contain customary cross default provisions.

7.750% Senior Notes due 2027

In October 2021, the Company issued $400.0 million of 7.750% Senior Notes and received net proceeds of approximately $395.0 million after deducting fees. We used the net proceeds, together with cash on hand, to refinance the $400.0 million Bridge Notes (which were issued during the fourth quarter of 2021 in connection with the completion of the acquisition of Anadarko WCTP) and to pay expenses related to the issuance of the 7.750% Senior Notes.

The 7.750% Senior Notes mature on May 1, 2027. Interest is payable in arrears each May 1 and November 1, commencing on May 1, 2022. The 7.750% Senior Notes are senior, unsecured obligations of Kosmos Energy Ltd. and rank equal in right of payment with all of its existing and future senior indebtedness (including all borrowings under the Corporate Revolver, the 7.125% Senior Notes and the 7.500% Senior Notes) and rank effectively junior in right of payment to all of its existing and future secured indebtedness (including all borrowings under the Facility). The 7.750% Senior Notes are guaranteed on a senior, unsecured basis by certain subsidiaries owning the Company's U.S. Gulf of Mexico assets, and on a subordinated, unsecured basis by certain subsidiaries that borrow under, or guarantee, the Facility and that guarantee the Corporate Revolver, the 7.125% Senior Notes and the 7.500% Senior Notes. The 7.750% Senior Notes contain customary cross default provisions.

At any time prior to November 1, 2023, and subject to certain conditions, the Company may, on one or more occasions, redeem up to 40% of the original principal amount of the 7.750% Senior Notes with an amount not to exceed the net cash proceeds of certain equity offerings at a redemption price of 107.750% of the outstanding principal amount of the 7.750% Senior Notes, together with accrued and unpaid interest and premium, if any, to, but excluding, the date of redemption. Additionally, at any time prior to November 1, 2023 the Company may, on any one or more occasions, redeem all or a part of the 7.750% Senior Notes at a redemption price equal to 100%, plus any accrued and unpaid interest, and plus a "make-whole" premium. On or after November 1, 2023, the Company may redeem all or a part of the 7.750% Senior Notes at the redemption prices (expressed as percentages of principal amount) set forth below plus accrued and unpaid interest:

Year	Percentage
On or after November 1, 2023	103.875 %
On or after November 1, 2024	101.938 %
On or after November 1, 2025	100.000 %

We may also redeem the 7.750% Senior Notes in whole, but not in part, at any time if changes in tax laws impose certain withholding taxes on amounts payable on the 7.750% Senior Notes at a price equal to the principal amount of the 7.750% Senior Notes plus accrued interest and additional amounts, if any, as may be necessary so that the net amount received by each holder after any withholding or deduction on payments of the 7.750% Senior Notes will not be less than the amount such holder would have received if such taxes had not been withheld or deducted.

Upon the occurrence of a change of control triggering event as defined under the 7.750% Senior Notes indenture, the Company will be required to make an offer to repurchase the 7.750% Senior Notes at a repurchase price equal to 101% of the principal amount, plus accrued and unpaid interest to, but excluding, the date of repurchase.

If we sell assets, under certain circumstances outlined in the 7.750% Senior Notes indenture, we will be required to use the net proceeds to make an offer to purchase the 7.750% Senior Notes at an offer price in cash in an amount equal to 100% of the principal amount of the 7.750% Senior Notes, plus accrued and unpaid interest to, but excluding, the repurchase date.

The 7.750% Senior Notes indenture restricts the ability of the Company and its restricted subsidiaries to, among other things: incur or guarantee additional indebtedness, create liens, pay dividends or make distributions in respect of capital stock, purchase or redeem capital stock, make investments or certain other restricted payments, sell assets, enter into agreements that restrict the ability of the Company's subsidiaries to make dividends or other payments to the Company, enter into transactions with affiliates, or effect certain consolidations, mergers or amalgamations. These covenants are subject to a number of important qualifications and exceptions. Certain of these covenants will be terminated if the 7.750% Senior Notes are assigned an investment grade rating by both Standard & Poor's Rating Services and Fitch Ratings Inc. and no default or event of default has occurred and is continuing. The 7.750% Senior Notes contain customary cross default provisions.

7.500% Senior Notes due 2028

In March 2021, the Company issued $450.0 million of 7.500% Senior Notes and received net proceeds of approximately $444.4 million after deducting fees. We used the net proceeds to repay outstanding indebtedness under the Corporate Revolver and the Facility, to pay expenses related to the issuance of the 7.500% Senior Notes and for general corporate purposes.

The 7.500% Senior Notes mature on March 1, 2028. Interest is payable in arrears each March 1 and September 1, commencing on September 1, 2021. The 7.500% Senior Notes are senior, unsecured obligations of Kosmos Energy Ltd. and rank equal in right of payment with all of its existing and future senior indebtedness (including all borrowings under the Corporate Revolver, the 7.125% Senior Notes and the 7.750% Senior Notes) and rank effectively junior in right of payment to all of its existing and future secured indebtedness (including all borrowings under the Facility). The 7.500% Senior Notes are guaranteed on a senior, unsecured basis by certain subsidiaries owning the Company's U.S. Gulf of Mexico assets, and on a subordinated, unsecured basis by certain subsidiaries that borrow under, or guarantee, the Facility and that guarantee the Corporate Revolver, and the 7.125% Senior Notes and the 7.750% Senior Notes. The 7.500% Senior Notes contain customary cross default provisions.

At any time prior to March 1, 2024, and subject to certain conditions, the Company may, on one or more occasions, redeem up to 40% of the original principal amount of the 7.500% Senior Notes with an amount not to exceed the net cash proceeds of certain equity offerings at a redemption price of 107.500% of the outstanding principal amount of the 7.500% Senior Notes, together with accrued and unpaid interest and premium, if any, to, but excluding, the date of redemption. Additionally, at any time prior to March 1, 2024 the Company may, on any one or more occasions, redeem all or a part of the 7.500% Senior Notes at a redemption price equal to 100%, plus any accrued and unpaid interest, and plus a "make-whole" premium. On or after March 1, 2024, the Company may redeem all or a part of the 7.500% Senior Notes at the redemption prices (expressed as percentages of principal amount) set forth below plus accrued and unpaid interest:

Year	Percentage
On or after March 1, 2024	103.750 %
On or after March 1, 2025	101.875 %
On or after March 1, 2026	100.000 %

We may also redeem the 7.500% Senior Notes in whole, but not in part, at any time if changes in tax laws impose certain withholding taxes on amounts payable on the 7.500% Senior Notes at a price equal to the principal amount of the 7.500% Senior Notes plus accrued interest and additional amounts, if any, as may be necessary so that the net amount received by each holder after any withholding or deduction on payments of the 7.500% Senior Notes will not be less than the amount such holder would have received if such taxes had not been withheld or deducted.

Upon the occurrence of a change of control triggering event as defined under the 7.500% Senior Notes indenture, the Company will be required to make an offer to repurchase the 7.500% Senior Notes at a repurchase price equal to 101% of the principal amount, plus accrued and unpaid interest to, but excluding, the date of repurchase.

If we sell assets, under certain circumstances outlined in the 7.500% Senior Notes indenture, we will be required to use the net proceeds to make an offer to purchase the 7.500% Senior Notes at an offer price in cash in an amount equal to 100% of the principal amount of the 7.500% Senior Notes, plus accrued and unpaid interest to, but excluding, the repurchase date.

The 7.500% Senior Notes indenture restricts the ability of the Company and its restricted subsidiaries to, among other things: incur or guarantee additional indebtedness, create liens, pay dividends or make distributions in respect of capital stock, purchase or redeem capital stock, make investments or certain other restricted payments, sell assets, enter into agreements that restrict the ability of the Company's subsidiaries to make dividends or other payments to the Company, enter into transactions with affiliates, or effect certain consolidations, mergers or amalgamations. These covenants are subject to a number of important qualifications and exceptions. Certain of these covenants will be terminated if the 7.500% Senior Notes are assigned an investment grade rating by both Standard & Poor's Rating Services and Fitch Ratings Inc. and no default or event of default has occurred and is continuing. The 7.500% Senior Notes contain customary cross default provisions.

GoM Term Loan

In September 2020, the Company entered into a five-year $200 million senior secured term-loan credit agreement secured against the Company's U.S. Gulf of Mexico assets with net proceeds received of $197.7 million after deducting fees and other expenses. On September 15, 2023, the Company repaid the remaining outstanding principal amount of $137.5 million plus accrued interest using cash on hand, constituting payment in full. The GoM Term Loan was subsequently terminated pursuant to, and subject to the terms of, the GoM Term Loan.

At December 31, 2023, the estimated repayments of debt during the five fiscal year periods and thereafter are as follows:

	Payments Due by Year						
	Total	2024	2025	2026	2027	2028	Thereafter
	(In thousands)						
Principal debt repayments(1)	$ 2,425,000	$ —	$ 300,000	$ 1,066,667	$ 608,333	$ 450,000	$ —

(1) Includes the scheduled maturities for outstanding principal debt balances. The scheduled maturities of debt related to the Facility as of December 31, 2023 are based on our level of borrowings and our estimated future available borrowing base commitment levels in future periods. Any increases or decreases in the level of borrowings or increases or decreases in the available borrowing base would impact the scheduled maturities of debt during the next five years and thereafter.

Interest and other financing costs, net

Interest and other financing costs, net incurred during the period comprised of the following:

	Years Ended December 31,		
	2023	2022	2021
	(In thousands)		
Interest expense	$ 207,629	$ 180,046	$ 146,706
Amortization—deferred financing costs	9,921	10,401	10,580
Loss on extinguishment of debt	1,503	192	19,625
Capitalized interest	(138,738)	(84,342)	(46,098)
Deferred interest	3,183	(3,318)	(3,401)
Interest income	(19,456)	(12,139)	(10,257)
Other, net	31,862	27,420	11,216
Interest and other financing costs, net	$ 95,904	$ 118,260	$ 128,371

Capitalized interest for the years ended December 31, 2023, 2022 and 2021 was $138.7 million, $84.3 million and $46.1 million, respectively, primarily relates to spend on the Greater Tortue Ahmeyim Phase 1 project. After first gas production on the Greater Tortue Ahmeyim Phase 1 project, which is targeted in the third quarter of 2024, we will no longer capitalize interest on the project.

9. Derivative Financial Instruments

We use financial derivative contracts to manage exposures to commodity price and interest rate fluctuations. We do not hold or issue derivative financial instruments for trading purposes.

We manage market and counterparty credit risk in accordance with our policies and guidelines. In accordance with these policies and guidelines, our management determines the appropriate timing and extent of derivative transactions. We have included an estimate of non-performance risk in the fair value measurement of our derivative contracts as required by ASC 820—Fair Value Measurements and Disclosures.

Oil Derivative Contracts

The following table sets forth the volumes in barrels underlying the Company’s outstanding oil derivative contracts and the weighted average prices per Bbl for those contracts as of December 31, 2023. Volumes and weighted average prices are net of any offsetting derivative contracts entered into.

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Term	Type of Contract	Index	MBbl	Weighted Average Price per Bbl: Net Deferred Premium Payable/(Receivable)	Sold Put	Floor	Ceiling
2024:							
Jan - Dec	Three-way collars	Dated Brent	4,000	1.31	45.00	70.00	96.25
Jan - Jun	Two-way collars	Dated Brent	2,000	1.24	—	65.00	85.00
Jan - Dec	Two-way collars	Dated Brent	2,000	0.46	—	70.00	100.00

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In January 2024, we entered into Dated Brent three-way collar contracts for 2.0 MMBbl from July 2024 through December 2024 with a sold put price of $45.00 per barrel, a floor price of $70.00 per barrel and a ceiling price of $90.00 per barrel.

See Note 10—Fair Value Measurements for additional information regarding the Company's derivative instruments.

The following tables disclose the Company's derivative instruments as of December 31, 2023 and 2022 and gain/(loss) from derivatives during the years ended December 31, 2023, 2022 and 2021.

Type of Contract	Balance Sheet Location	Estimated Fair Value Asset (Liability) December 31, 2023	2022
		(In thousands)	
Derivatives not designated as hedging instruments:			
Derivative assets:			
Commodity	Derivatives assets—current	$ 8,346	$ 7,344
Provisional oil sales	Receivables: Oil sales	(72)	1,170
Commodity	Derivatives assets—long-term	1,594	1,725
Derivative liabilities:			
Commodity	Derivatives liabilities—current	(3,103)	(6,773)
Commodity	Derivatives liabilities—long-term	—	(778)
Total derivatives not designated as hedging instruments		$ 6,765	$ 2,688

Type of Contract	Location of Gain/(Loss)	Amount of Gain/(Loss) Years Ended December 31, 2023	2022	2021
		(In thousands)		
Derivatives not designated as hedging instruments:				
Provisional oil sales	Oil and gas revenue	$ (17,221)	$ (14,573)	$ (7,520)
Commodity	Derivatives, net	(11,128)	(260,892)	(270,185)
Total derivatives not designated as hedging instruments		$ (28,349)	$ (275,465)	$ (277,705)

Offsetting of Derivative Assets and Derivative Liabilities

Our derivative instruments which are subject to master netting arrangements with our counterparties only have the right of offset when there is an event of default. As of December 31, 2023 and 2022, there was not an event of default and, therefore, the associated gross asset or gross liability amounts related to these arrangements are presented on the consolidated balance sheets.

10. Fair Value Measurements

In accordance with ASC 820—Fair Value Measurements, fair value measurements are based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources, whereas unobservable inputs reflect a company's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. We prioritize the inputs used in measuring fair value into the following fair value hierarchy:

- Level 1 — quoted prices for identical assets or liabilities in active markets.
- Level 2 — quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs derived principally from or corroborated by observable market data by correlation or other means.
- Level 3 — unobservable inputs for the asset or liability. The fair value input hierarchy level to which an asset or liability measurement in its entirety falls is determined based on the lowest level input that is significant to the measurement in its entirety.

The following tables present the Company's assets and liabilities that are measured at fair value on a recurring basis as of December 31, 2023 and 2022, for each fair value hierarchy level:

	Fair Value Measurements Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(In thousands)			
December 31, 2023				
Assets:				
Commodity derivatives	$ —	$ 9,940	$ —	$ 9,940
Provisional oil sales	—	(72)	—	(72)
Liabilities:				
Commodity derivatives	—	(3,103)	—	(3,103)
Total	$ —	$ 6,765	$ —	$ 6,765
December 31, 2022				
Assets:				
Commodity derivatives	$ —	$ 9,069	$ —	$ 9,069
Provisional oil sales	—	1,170	—	1,170
Liabilities:				
Commodity derivatives	—	(7,551)	—	(7,551)
Total	$ —	$ 2,688	$ —	$ 2,688

The book values of cash and cash equivalents and restricted cash approximate fair value based on Level 1 inputs. Joint interest billings, oil sales and other receivables, and accounts payable and accrued liabilities approximate fair value due to the short-term nature of these instruments. Our long-term receivables, after any allowances for credit losses, and other long-term assets approximate fair value. The estimates of fair value of these items are based on Level 2 inputs.

Commodity Derivatives

Our commodity derivatives represent crude oil collars, put options and call options for notional barrels of oil at fixed Dated Brent or NYMEX WTI oil prices. The values attributable to our oil derivatives are based on (i) the contracted notional volumes, (ii) independent active futures price quotes for the respective index, (iii) a credit-adjusted yield curve applicable to each counterparty by reference to the credit default swap ("CDS") market and (iv) an independently sourced estimate of volatility for the respective index. The volatility estimate was provided by certain independent brokers who are active in buying and selling oil options and was corroborated by market-quoted volatility factors. The deferred premium is included in the fair market value of the commodity derivatives. See Note 9—Derivative Financial Instruments for additional information regarding the Company's derivative instruments.

Provisional Oil Sales

The value attributable to provisional oil sales derivative is based on (i) the sales volumes and (ii) the difference in the independent active futures price quotes for the respective index over the term of the pricing period designated in the sales contract and the spot price on the lifting date.

Debt

The following table presents the carrying values and fair values at December 31, 2023 and 2022:

	December 31, 2023		December 31, 2022	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In thousands)			
7.125% Senior Notes	$ 646,912	$ 622,824	$ 645,699	$ 558,201
7.750% Senior Notes	396,718	374,764	395,893	335,592
7.500% Senior Notes	446,291	412,461	445,564	361,958
GoM Term Loan	—	—	145,000	145,000
Facility	925,000	925,000	625,000	625,000
Total	$ 2,414,921	$ 2,335,049	$ 2,257,156	$ 2,025,751

The carrying values of our 7.125% Senior Notes, 7.750% Senior Notes and 7.500% Senior Notes represent the principal amounts outstanding less unamortized discounts. The fair values of our 7.125% Senior Notes, 7.750% Senior Notes and 7.500% Senior Notes are based on quoted market prices, which results in a Level 1 fair value measurement. The carrying values of the GoM Term Loan and Facility approximate fair value since they are subject to short-term floating interest rates that approximate the rates available to us for those periods.

Nonrecurring Fair Value Measurements - Long-lived assets

Certain long-lived assets are reported at fair value on a non-recurring basis on the Company's consolidated balance sheet. These long-lived assets are not measured at fair value on an ongoing basis but are subject to fair value adjustments in certain circumstances. Our long-lived assets are reviewed for impairment when changes in circumstances indicate that the carrying amount of an asset may not be recoverable.

The Company calculates the estimated fair values of its long-lived assets using the income approach described in the ASC 820 — Fair Value Measurements. Significant inputs associated with the calculation of estimated discounted future net cash flows include anticipated future production, pricing estimates, capital and operating costs, market-based weighted average cost of capital, and risk adjustment factors applied to reserves. These are classified as Level 3 fair value assumptions. The Company utilizes an average of third-party industry forecasts of Dated Brent, adjusted for location and quality differentials, to determine our pricing assumptions. In order to evaluate the sensitivity of the assumptions, we analyze sensitivities to prices, production, and risk adjustment factors.

As a result of negative proved oil and natural gas reserve revisions at TEN, primarily driven by a change in the partnership's development work scope for the TEN Fields and well performance, we reviewed our TEN long-lived assets for impairment at December 31, 2023, which resulted impairment charges of $222.3 million for the year ended December 31, 2023. The impairment charges resulted in a full impairment of the remaining book value of TEN reducing the carrying value of the TEN Fields to zero. As part of our impairment analysis, the average per barrel Dated Brent price of third-party industry forecasts used for purposes of determining discounted future cash flows was in the low-$80s adjusted for inflation. The expected future cash flows were discounted using a rate of approximately 10 percent which the Company believes is a market-based weighted average cost of capital for industry peers determined appropriate at the time of the valuation.

As a result of a negative proved oil and natural gas reserve revision at TEN, primarily driven by well performance, we reviewed our TEN long-lived assets for impairment at December 31, 2022, which resulted in impairment charges of 450.0 million for the year ended December 31, 2022, reducing the carrying value of the TEN Fields to the estimated fair value of $235.7 million as of December 31, 2022. As part of our impairment analysis, the average per barrel Dated Brent price of third-party industry forecasts used for purposes of determining discounted future cash flows was in the low-$80s adjusted for inflation. We also took account of the delayed future investment in the field. The expected future cash flows were discounted using a rate of approximately 10 percent which the Company believes is a market-based weighted average cost of capital for industry peers determined appropriate at the time of the valuation.

No impairment of proved oil and gas properties was recognized for the year December 31, 2021 as no impairment indicators were identified.

These impairment charges are included in Impairments of long-lived assets on the consolidated statement of operations. If we experience material declines in oil pricing expectations, increases in our estimated future expenditures or a decrease in our estimated production profile, our long-lived assets could be at risk of additional impairment.

11. Asset Retirement Obligations

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

	December 31,	
	2023	2022
	(In thousands)	
Asset retirement obligations:		
Beginning asset retirement obligations	$ 302,534	$ 325,459
Liabilities incurred during period	16,196	13,696
Liabilities settled during period	(13,082)	(9,277)
Revisions in estimated retirement obligations	11,527	(50,600)
Accretion expense	29,611	23,256
Ending asset retirement obligations	$ 346,786	$ 302,534

The asset retirement obligations reflect the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with our oil and gas properties. The Company utilizes current cost experience to estimate the expected cash outflows for retirement obligations. The Company estimates the ultimate productive life of the properties, a risk-adjusted discount rate, and an inflation factor in order to determine the current present value of this obligation. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation, a corresponding adjustment is made to the oil and gas property balance. The revisions in estimated retirement obligations during 2023 and 2022 are related to changes in the estimated timing, scopes of work and costs. During the year ended December 31, 2022, our asset retirement obligations were reduced by approximately $10.0 million as a result of concluding the Tullow pre-emption transaction in March 2022 and approximately $66.2 million as a result of the extension of the Block G licenses in Equatorial Guinea in May 2022.

12. Equity-based Compensation

Restricted Stock Awards and Restricted Stock Units

Our Long-Term Incentive Plan (“LTIP”) provides for the granting of incentive awards in the form of stock options, stock appreciation rights, restricted stock awards, restricted stock units, among other award types. In June 2023, the Company’s stockholders approved the Amended and Restated Kosmos Energy Ltd. LTIP, which authorized an additional 17.0 million shares of common stock available for issuance under the LTIP. The LTIP as amended provides for the issuance of 78.5 million shares pursuant to awards under the LTIP. As of December 31, 2023, the Company had approximately 18.6 million shares that remain available for issuance under the LTIP.

The Company granted restricted stock units with service vesting criteria and with a combination of market and service vesting criteria under the LTIP. Substantially, all of these awards vest over a three year period. Upon vesting, restricted stock units become issued and outstanding stock.

The following table reflects the outstanding restricted stock units as of December 31, 2023:

	Service Vesting Restricted Stock Units (In thousands)	Weighted- Average Grant-Date Fair Value	Market / Service Vesting Restricted Stock Units (In thousands)	Weighted-Average Grant-Date Fair Value
Outstanding at December 31, 2020:	4,840	$ 5.34	7,859	$ 8.11
Granted(1)	2,905	2.57	6,744	3.91
Forfeited(1)	(649)	4.05	(1,998)	5.50
Vested	(2,400)	5.19	(1,372)	9.95
Outstanding at December 31, 2021:	4,696	3.88	11,233	5.28
Granted(1)	2,820	4.70	3,388	6.98
Forfeited(1)	(147)	3.92	(389)	6.21
Vested	(2,453)	4.21	(2,191)	5.98
Outstanding at December 31, 2022:	4,916	4.18	12,041	5.61
Granted(1)	2,809	7.61	3,482	12.26
Forfeited(1)	(240)	5.65	(203)	8.17
Vested	(2,775)	3.86	(2,950)	8.22
Outstanding at December 31, 2023:	4,710	5.77	12,370	6.59

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(1) The restricted stock units with a combination of market and service vesting criteria may vest between 0% and 200% of the originally granted units depending upon market performance conditions. Awards vesting over or under target shares of 100% results in additional shares granted or forfeited, respectively, in the period the market vesting criteria is determined.

As of December 31, 2023, total equity-based compensation to be recognized on unvested restricted stock units is $27.8 million over a weighted average period of 1.8 years.

For restricted stock units with a combination of market and service vesting criteria, the number of common shares to be issued is determined by comparing the Company’s total shareholder return with the total shareholder return of a predetermined group of peer companies over the performance period and can vest in up to 200% of the awards granted. The grant date fair value ranged from $1.06 to $13.06 per award. The Monte Carlo simulation model utilizes multiple input variables that determined the probability of satisfying the market condition stipulated in the award grant and calculates the fair value of the award. The expected volatility utilized in the model was estimated using our historical volatility and the historical volatilities of our peer companies and ranged from 50.0% to 105.0%. The risk-free interest rate was based on the U.S. treasury rate for a term commensurate with the expected life of the grant ranged from 0.2% to 3.7%. The expected quarterly dividends ranged from $0.000 to $0.050 commensurate with our current dividend experience.

In January 2024, we granted 2.4 million service vesting restricted stock units and 3.0 million market and service vesting restricted stock units to our employees under our long-term incentive plan. We expect to recognize approximately $41.4 million of non-cash compensation expense related to these grants over the next three years.

We record equity-based compensation expense in General and administrative expenses in our consolidated statement of operations equal to the grant date fair value of share-based payments over the vesting periods of the LTIP awards. The following table summarizes certain information related to our share-based payments:

	Years Ended December 31,		
	2023	2022	2021
	(In thousands)		
Share-based compensation expense	$ 42,693	$ 34,546	$ 31,651
Total tax benefit	7,482	5,933	5,786
Net tax shortfall (windfall)	(3,201)	673	6,307
Fair value of awards vested	45,098	22,205	9,435

13. Income Taxes

We provide for income taxes based on the laws and rates in effect in the countries in which our operations are conducted. The relationship between our pre-tax income or loss from continuing operations and our income tax expense or benefit varies from period to period as a result of various factors which include changes in total pre-tax income or loss, the jurisdictions in which our income (loss) is earned and the tax laws in those jurisdictions.

During the year ended December 31, 2023, our net deferred tax liability decreased by approximately $107.6 million primarily as a result of a $222.3 million impairment related to the TEN Field, which resulted in a reduction in our deferred tax liability of $77.8 million, with the remaining $29.8 million decrease in our deferred tax liability primarily related to the timing of the reversal of temporary differences. During the year ended December 31, 2022, our net deferred tax liability decreased by approximately $242.7 million, primarily as a result of a $450.0 million impairment related to the TEN Field, which resulted in a reduction in our deferred tax liability of approximately $157.6 million, and a $44.6 million of the decrease related to closing the Tullow pre-emption transaction in March 2022 (See Note 3 - Acquisitions and Divestitures), and the remaining $40.5 million decrease in our deferred tax liability primarily related to the timing of the reversal of temporary differences.

Income (loss) before income taxes is composed of the following:

	Years Ended December 31,		
	2023	2022	2021
	(In thousands)		
United States	$ (88,458)	$ 73,529	$ (75,948)
Foreign	460,193	263,538	32,568
Income (loss) before income taxes	$ 371,735	$ 337,067	$ (43,380)

The components of the provision for income taxes attributable to our income (loss) before income taxes consist of the following:

	Years Ended December 31,		
	2023	2022	2021
	(In thousands)		
Current:			
United States	$ 865	$ 7,174	$ 282
Foreign	264,910	300,829	103,348
Total current	265,775	308,003	103,630
Deferred:			
United States	551	84	1,202
Foreign	(108,111)	(197,571)	(70,376)
Total deferred	(107,560)	(197,487)	(69,174)
Income tax expense	$ 158,215	$ 110,516	$ 34,456

Our reconciliation of income tax expense (benefit) computed by applying our statutory rate and the reported effective tax rate on income or (loss) from continuing operations is as follows:

	Years Ended December 31,		
	2023	2022	2021
	(In thousands)		
Tax at statutory rate	$ 78,064	$ 70,784	$ (9,110)
Foreign income (loss) taxed at different rates	48,768	20,663	17,344
Non-deductible compensation	5,915	3,012	2,775
Non-deductible and other items	2,243	3,993	1,719
Tax shortfall (windfall) on equity-based compensation, net	(3,201)	673	6,307
Change in valuation allowance	26,426	11,391	15,421
Total tax expense (benefit)	$ 158,215	$ 110,516	$ 34,456
Effective tax rate	43 %	33 %	79 %

(1) The effective tax rate during the years ended December 31, 2023, 2022 and 2021, were impacted by (gains) and losses of $(4.0) million, $21.0 million and $61.6 million, respectively, incurred in jurisdictions in which we are not subject to taxes and therefore do not generate any income tax benefits or where there are valuation allowances offsetting the corresponding deferred tax assets.

The effective tax rate for the United States is approximately (2%), 10% and 2% for the years ended December 31, 2023, 2022 and 2021, respectively. The effective tax rate in the United States is impacted by the effect of non-deductible expenditures and equity-based compensation tax shortfalls and tax windfalls equal to the difference between the income tax benefit recognized for financial statement reporting purposes compared to the income tax benefit realized for tax return purposes. For the years ended December 31, 2023, 2022 and 2021, our effective tax rate in the United States is impacted by changes in valuation allowances on a portion of our deferred tax assets totaling $12.1 million, $(12.3) million and $6.6 million, respectively.

The effective tax rate for Ghana is approximately 36%, 35% and 35% for the years ended December 31, 2023, 2022 and 2021, respectively. The effective tax rate in Ghana is impacted by non-deductible expenditures.

The effective tax rate for Equatorial Guinea is approximately 35%, 36% and 35% for the years ended December 31, 2023, 2022 and 2021, respectively, and is impacted by non-deductible expenditures.

Our operations in other foreign jurisdictions have a 0% effective tax rate because they reside in countries with a 0% statutory rate or we have incurred losses in those countries and have full valuation allowances against the corresponding net deferred tax assets.

Deferred tax assets and liabilities, which are computed on the estimated income tax effect of temporary differences between financial and tax bases in assets and liabilities, are determined using the tax rates expected to be in effect when taxes are actually paid or recovered. In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. The tax effects of significant temporary differences giving rise to deferred tax assets and liabilities are as follows:

	December 31,	
	2023	2022
	(In thousands)	
Deferred tax assets:		
Foreign capitalized operating expenses	$ 209,453	$ 196,018
Foreign net operating losses	14,458	19,297
United States net operating losses	78,706	81,040
United States deferred interest expense	43,411	17,421
Equity compensation	10,867	7,916
Asset retirement obligation and other	78,024	67,083
Total deferred tax assets	434,919	388,775
Valuation allowance	(333,651)	(312,968)
Total deferred tax assets, net	101,268	75,807
Deferred tax liabilities:		
Depletion, depreciation and amortization related to property and equipment	(420,066)	(512,019)
Other deferred tax liabilities	(42,087)	(32,233)
Total deferred tax liabilities	(462,153)	(544,252)
Net deferred tax liability	$ (360,885)	$ (468,445)

The Company has foreign net operating loss carryforwards of $48.2 million, that will not expire. Additionally, the Company has $374.8 million of United States net operating loss that will not expire. All of these losses currently have offsetting valuation allowances.

The Company is open to tax examinations in the United States for federal income tax return years 2020 through 2022, in Ghana for income tax return years 2019 through 2022, and in Equatorial Guinea for income tax return years 2019 through 2022.

As of December 31, 2023, the Company had no material uncertain tax positions. The Company's policy is to recognize potential interest and penalties related to income tax matters in income tax expense.

14. Net Income (Loss) Per Share

In the calculation of basic net income per share, participating securities are allocated earnings based on actual dividend distributions received plus a proportionate share of undistributed net income, if any. We calculate basic net income per share under the two-class method. Diluted net income (loss) per share is calculated under both the two-class method and the treasury stock method and the more dilutive of the two calculations is presented. The computation of diluted net income (loss) per share reflects the potential dilution that could occur if all outstanding awards under our LTIP were converted into shares of common stock or resulted in the issuance of shares of common stock that would then share in the earnings of the Company. During periods in which the Company realizes a loss from continuing operations securities would not be dilutive to net loss per share and conversion into shares of common stock is assumed not to occur.

Basic net income (loss) per share is computed as (i) net income (loss), (ii) less income allocable to participating securities (iii) divided by weighted average basic shares outstanding. The Company's diluted net income (loss) per share is computed as (i) basic net income (loss), (ii) plus diluted adjustments to income allocable to participating securities (iii) divided by weighted average diluted shares outstanding.

	Years Ended December 31,		
	2023	2022	2021
	(In thousands, except per share data)		
Numerator:			
Net income (loss) allocable to common stockholders	$ 213,520	$ 226,551	$ (77,836)
Denominator:			
Weighted average number of shares outstanding:			
Basic	459,641	455,346	416,943
Restricted stock units(1)	21,429	19,511	—
Diluted	481,070	474,857	416,943
Net income (loss) per share:			
Basic	$ 0.46	$ 0.50	$ (0.19)
Diluted	$ 0.44	$ 0.48	$ (0.19)

(1) Our restricted stock units are not considered to be participating securities and, therefore, are excluded from the basic net income (loss) per share calculation.

(2) For the years ended December 31, 2023, 2022 and 2021, we excluded 0.0, 0.1 million and 19.0 million outstanding restricted stock units, respectively, from the computations of diluted net income per share because the effect would have been anti-dilutive.

15. Commitments and Contingencies

From time to time, we are involved in litigation, regulatory examinations and administrative proceedings primarily arising in the ordinary course of our business in jurisdictions in which we do business. Although the outcome of these matters cannot be predicted with certainty, management believes none of these matters, either individually or in the aggregate, would have a material effect upon the Company's financial position; however, an unfavorable outcome could have a material adverse effect on our results from operations for a specific interim period or year.

We have a commitment to drill three development wells and one exploration well in Equatorial Guinea. We have a $200.2 million FPSO Contract Liability in Other long-term liabilities related to the deferred sale of the Greater Tortue FPSO.

In February 2019, Kosmos and BP signed Carry Advance Agreements with the national oil companies of Mauritania and Senegal, which obligate us separately to finance the respective national oil companies' share of certain development costs. Kosmos' total share for the two agreements combined is currently estimated at approximately $300.0 million, of which $259.2 million has been incurred through December 31, 2023, excluding accrued interest.

Performance Obligations

As of December 31, 2023 and 2022, the Company had performance bonds and supplemental bonds totaling $194.1 million and $205.2 million, respectively, related to bonding requirements stipulated by the BOEM and other third parties for anticipated plugging and abandonment costs of certain wells and the removal of certain facilities in our U.S. Gulf of Mexico fields.

16. Additional Financial Information

Accrued Liabilities

Accrued liabilities consisted of the following:

	December 31,			
	2023		2022	
	(In thousands)			
Accrued liabilities:				
Exploration, development and production	$	90,054	$	80,598
Revenue payable		20,506		26,087
Current asset retirement obligations		2,808		1,732
General and administrative expenses		29,766		32,069
Interest		36,410		44,740
Income taxes		111,212		127,183
Taxes other than income		1,029		1,524
Derivatives		1,372		6,440
Other		9,658		4,833
	$	302,815	$	325,206

Gain on sale of assets

During the fourth quarter of 2022, we received formal notice from Shell that an appraisal plan for one well had been submitted under the terms of Shell's Petroleum Agreement with Namibia. As a result, we recognized a $50.0 million gain related to the proceeds of $50.0 million received in the fourth quarter of 2022 related to the 2020 farm-out agreement with Shell.

Other Expenses, net

Other expenses, net incurred during the period is comprised of the following:

	Years Ended December 31,					
	2023		2022		2021	
	(In thousands)					
Loss on disposal of inventory	$	7,372	$	1,521	$	1,239
Gain on insurance settlements		—		(7,000)		—
(Gain) loss on asset retirement obligations liability settlements		6,034		(3,278)		6,351
Other, net		10,250		(297)		2,521
Other expenses, net	$	23,656	$	(9,054)	$	10,111

17. Business Segment Information

Kosmos is engaged in a single line of business, which is the exploration, development and production of oil and gas. At December 31, 2023, the Company had operations in four geographic reporting segments: Ghana, Equatorial Guinea, Mauritania/Senegal and the U.S. Gulf of Mexico. To assess performance of the reporting segments, the Chief Operating Decision Maker reviews capital expenditures. Capital expenditures, as defined by the Company, may not be comparable to similarly titled measures used by other companies and should be considered in conjunction with our consolidated financial statements and notes thereto. Financial information for each area is presented below:

	Ghana	Equatorial Guinea	Mauritania / Senegal	U.S. Gulf of Mexico	Corporate & Other	Eliminations	Total
				(in thousands)			
Years ended December 31, 2023							
Revenues and other income:							
Oil and gas revenue	$ 1,062,482	$ 267,494	$ —	$ 371,632	$ —	$ —	$ 1,701,608
Other income, net	(403)	10	—	3,327	157,770	(160,777)	(73)
Total revenues and other income	1,062,079	267,504	—	374,959	157,770	(160,777)	1,701,535
Costs and expenses:							
Oil and gas production	175,265	114,411	—	100,421	—	—	390,097
Exploration expenses	872	7,915	15,784	11,950	5,757	—	42,278
General and administrative	12,913	5,555	9,354	22,076	199,283	(149,649)	99,532
Depletion, depreciation and amortization	240,998	51,750	917	149,482	1,780	—	444,927
Impairment of long-lived assets	222,278	—	—	—	—	—	222,278
Interest and other financing costs, net(1)	56,988	(2,942)	(119,697)	6,236	155,319	—	95,904
Derivatives, net	—	—	—	—	11,128	—	11,128
Other expenses, net	7,963	3,208	7,997	10,506	5,110	(11,128)	23,656
Total costs and expenses	717,277	179,897	(85,645)	300,671	378,377	(160,777)	1,329,800
Income (loss) before income taxes	344,802	87,607	85,645	74,288	(220,607)	—	371,735
Income tax expense	122,704	35,666	—	13,643	(13,798)	—	158,215
Net income (loss)	$ 222,098	$ 51,941	$ 85,645	$ 60,645	$ (206,809)	$ —	$ 213,520
Consolidated capital expenditures	$ 276,849	$ 74,573	$ 276,484	$ 212,431	$ 9,662	$ —	$ 849,999
As of December 31, 2023							
Property and equipment, net	$ 1,036,651	$ 424,030	$ 1,788,214	$ 893,293	$ 18,041	$ —	$ 4,160,229
Total assets	$ 3,252,235	$ 1,918,131	$ 2,642,098	$ 3,988,805	$ 21,599,662	$ (28,462,797)	$ 4,938,134

(1) Interest expense is recorded based on actual third-party and intercompany debt agreements. Capitalized interest is recorded on the business unit where the assets reside.

	Ghana (2)	Equatorial Guinea	Mauritania / Senegal	U.S. Gulf of Mexico (3)	Corporate & Other	Eliminations	Total
				(in thousands)			
Year ended December 31, 2022							
Revenues and other income:							
Oil and gas revenue	$ 1,350,962	$ 346,783	$ —	$ 547,610	$ —	$ —	$ 2,245,355
Gain on sale of assets	—	—	—	471	50,000	—	50,471
Other income, net	428	3,350	—	2,405	386,002	(388,236)	3,949
Total revenues and other income	1,351,390	350,133	—	550,486	436,002	(388,236)	2,299,775
Costs and expenses:							
Oil and gas production	206,486	90,602	—	105,968	—	—	403,056
Facilities insurance modifications, net	6,243	—	—	—	—	—	6,243
Exploration expenses	14,987	7,378	82,526	22,763	6,576	—	134,230
General and administrative	15,310	6,703	9,798	15,794	180,594	(127,343)	100,856
Depletion, depreciation and amortization	289,058	53,765	412	153,407	1,614	—	498,256
Impairment of long-lived assets	450,357	—	—	(388)	—		449,969
Interest and other financing costs, net(1)	64,620	(2,494)	(69,644)	11,180	114,598	—	118,260
Derivatives, net	—	—	—	—	260,892	—	260,892
Other expenses, net	233,785	8,397	(1,178)	10,339	496	(260,893)	(9,054)
Total costs and expenses	1,280,846	164,351	21,914	319,063	564,770	(388,236)	1,962,708
Income (loss) before income taxes	70,544	185,782	(21,914)	231,423	(128,768)	—	337,067
Income tax expense (benefit)	28,091	72,814	—	(1,010)	10,621	—	110,516
Net income (loss)	$ 42,453	$ 112,968	$ (21,914)	$ 232,433	$ (139,389)	$ —	$ 226,551
Consolidated capital expenditures	$ 98,540	$ 36,036	$ 407,982	$ 111,016	$ (41,986)	$ —	$ 611,588
As of December 31, 2022							
Property and equipment, net	$ 1,202,937	$ 396,737	$ 1,396,884	$ 829,242	$ 16,847	$ —	$ 3,842,647
Total assets	$ 2,886,242	$ 1,463,211	$ 2,026,776	$ 3,695,641	$ 19,554,236	$ (25,046,118)	$ 4,579,988

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(1) Interest expense is recorded based on actual third-party and intercompany debt agreements. Capitalized interest is recorded on the business unit where the assets reside.

(2) Includes activity related to the interest pre-empted by Tullow prior to the March 17, 2022 closing date of the Tullow pre-emption transaction. Additionally, cash consideration of $118.2 million is included as a reduction in Consolidated capital expenditures for the year ended December 31, 2022.

(3) Includes activity related to our acquisition of an additional interest in the Kodiak oil field commencing June 9, 2022, the acquisition date. Additionally, cash consideration paid of $29.0 million is included in the Consolidated capital expenditures for the year ended December 31, 2022.

	Ghana (2)	Equatorial Guinea	Mauritania / Senegal	U.S. Gulf of Mexico	Corporate & Other	Eliminations	Total
				(in thousands)			
Year ended December 31, 2021							
Revenues and other income:							
Oil and gas revenue	$ 644,232	$ 260,520	$ —	$ 427,261	$ —	$ —	$ 1,332,013
Gain on sale of assets	—	—	—	—	1,564	—	1,564
Other income, net	6	—	—	1,279	395,073	(396,096)	262
Total revenues and other income	644,238	260,520	—	428,540	396,637	(396,096)	1,333,839
Costs and expenses:							
Oil and gas production	151,079	93,032	—	101,895	—	—	346,006
Facilities insurance modifications, net	(1,586)	—	—	—	—	—	(1,586)
Exploration expenses	1,527	5,700	10,639	41,230	6,286	—	65,382
General and administrative	12,179	4,343	8,601	17,665	172,869	(124,128)	91,529
Depletion, depreciation and amortization	240,901	56,468	61	168,142	1,649	—	467,221
Interest and other financing costs, net(1)	51,279	(1,661)	(44,831)	15,875	109,493	(1,784)	128,371
Derivatives, net	—	—	—	—	270,185	—	270,185
Other expenses, net	206,466	41,891	(2,189)	30,118	4,010	(270,185)	10,111
Total costs and expenses	661,845	199,773	(27,719)	374,925	564,492	(396,097)	1,377,219
Income (loss) before income taxes	(17,607)	60,747	27,719	53,615	(167,855)	1	(43,380)
Income tax expense (benefit)	(4,290)	37,487	—	(4,958)	6,217	—	34,456
Net income (loss)	$ (13,317)	$ 23,260	$ 27,719	$ 58,573	$ (174,072)	$ 1	$ (77,836)
Consolidated capital expenditures	$ 575,472	$ 77,364	$ 170,690	$ 96,897	$ 3,791	$ —	$ 924,214
As of December 31, 2021							
Property and equipment, net	$ 1,885,116	$ 460,975	$ 918,683	$ 901,392	$ 17,821	$ —	$ 4,183,987
Total assets	$ 3,125,835	$ 911,159	$ 1,346,622	$ 3,258,264	$ 17,108,138	$ (20,809,367)	$ 4,940,651

(1) Interest expense is recorded based on actual third-party and intercompany debt agreements. Capitalized interest is recorded on the business unit where the assets reside.

(2) Includes activity related to our acquisition of additional interests in Ghana commencing October 13, 2021, the acquisition date. Additionally, the acquisition purchase price of $465.4 million is included in Consolidated capital expenditures.

	Years Ended December 31,		
	2023	2022	2021
	(In thousands)		
Consolidated capital expenditures:			
Consolidated Statements of Cash Flows - Investing activities:			
Oil and gas assets	$ 932,603	$ 787,297	$ 472,631
Acquisition of oil and gas properties	—	22,078	465,367
Proceeds on sale of assets	—	(168,703)	(6,354)
Adjustments:			
Changes in capital accruals	6,732	396	(18,534)
Exploration expense, excluding unsuccessful well costs and leasehold impairments(1)	40,070	47,289	46,563
Capitalized interest	(138,738)	(84,343)	(46,098)
Other	9,332	7,574	10,639
Total consolidated capital expenditures	$ 849,999	$ 611,588	$ 924,214

(1) Unsuccessful well costs are included in oil and gas assets when incurred.

KOSMOS ENERGY LTD.
Supplemental Oil and Gas Data (Unaudited)

Net proved oil and gas reserve estimates presented were prepared by Ryder Scott Company, L.P. ("RSC") for the years ended December 31, 2023, 2022 and 2021. RSC are independent petroleum engineers located in Houston, Texas. RSC has prepared the reserve estimates presented herein and meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to independent reserve engineers for their reserves estimation process.

Net Proved Developed and Undeveloped Reserves

The following table is a summary of net proved developed and undeveloped oil and gas reserves to Kosmos' interests in Ghana, Equatorial Guinea, Mauritania, Senegal and the U.S. Gulf of Mexico.

	Ghana	Equatorial Guinea	Mauritania / Senegal	U.S. Gulf of Mexico	Total Oil	Ghana	Equatorial Guinea	Mauritania / Senegal	U.S. Gulf of Mexico	Total Gas	Kosmos Total
	Oil, Condensate, NGLs (MMBbls)(4)					Natural Gas (Bcf)					(MMBoe)
Net proved developed and undeveloped reserves at December 31, 2020(1)	68	24	—	34	127	31	11	—	27	69	139
Extensions and discoveries	—	—	—	—	—	—	—	—	—	—	—
Production	(10)	(4)	—	(6)	(20)	—	—	—	(5)	(5)	(21)
Revision in estimate(2)	10	4	8	4	26	10	—	590	5	605	127
Purchases of minerals-in-place(3)	52	—	—	—	52	27	—	—	—	27	57
Net proved developed and undeveloped reserves at December 31, 2021(1)	120	24	8	32	185	68	11	590	27	695	301
Extensions and discoveries	—	—	—	3	3	—	—	28	1	29	8
Production	(13)	(4)	—	(6)	(23)	—	—	—	(4)	(4)	(24)
Revision in estimate(2)	7	4	(1)	(2)	7	(5)	5	(1)	—	—	7
Purchases of minerals-in-place	—	—	—	1	1	—	—	—	—	—	1
Sales of minerals-in-place	(14)	—	—		(14)	(14)	—	—	—	(14)	(16)
Net proved developed and undeveloped reserves at December 31, 2022(1)	99	25	7	27	158	49	16	618	24	707	276
Extensions and discoveries	3	—	—	—	3	5	—	—	—	5	4
Production	(13)	(3)	—	(5)	(21)	(10)	(1)	—	(4)	(15)	(24)
Revision in estimate(2)	4	2	—	(1)	5	91	1	10	(2)	100	22
Purchase of minerals-in-place	—	—	—	—	—	—	—	—	—	—	—
Sales of minerals-in-place	—	—	—	—	—	—	—	—	—	—	—
Net proved developed and undeveloped reserves at December 31, 2023(1)	93	24	7	21	145	135	16	628	18	797	278
Proved developed reserves(1)											
December 31, 2020	26	21	—	32	79	23	11	—	25	59	89
December 31, 2021	52	20	—	28	100	56	11	—	20	87	115
December 31, 2022	43	20	—	21	84	40	16	—	17	73	96
December 31, 2023	46	19	—	15	81	79	16	—	12	106	99
Proved undeveloped reserves(1)(5)											
December 31, 2020	42	4	—	2	48	8	—	—	2	10	50
December 31, 2021	68	5	8	4	85	12	—	590	6	608	186
December 31, 2022	56	5	7	6	74	9	—	618	7	634	180
December 31, 2023	47	5	7	6	64	56	—	628	6	690	179

(1) The sum of proved developed reserves and proved undeveloped reserves may not add to net proved developed and undeveloped reserves as a result of rounding.

(2) The revisions in estimates in 2023 are related to:

- In Ghana, Jubilee had a positive revision of 14.3 MMBbl and 125.1 Bcf primarily due to positive field performance, the addition of gas sales recognition and positive drilling results, offset by Jubilee net production of 11.2 MMBbl and 9.7 Bcf. TEN had a negative revision of 7.8 MMBbl and 28.4 Bcf primarily driven by a change in the partnership's development work scope for the TEN Fields and well performance as well as net TEN production of 1.3 MMBbl. Overall, for the year ended December 31, 2023, Jubilee had an increase in reserves of 3.1 MMBbl and 115.3 Bcf and TEN had a decrease in reserves of 9.1 MMBbl and 28.4 Bcf. We note that the decrease in commodity prices did not result in revisions of estimates.
- In Equatorial Guinea, we had a commodity price-related reserves decrease of 0.3 MMBbl and 0.6 Bcf in Ceiba and 0.2 MMBbl and 0.3 Bcf in Okume, with an additional decrease from net production of 0.9 MMBbl and 0.5 Bcf in Ceiba and 2.3 MMBbl and 0.9 Bcf in Okume. Production performance and topsides optimization resulted in an increase of 1.5 MMBbl and 1.6 Bcf in Ceiba and an increase of 1.6 MMBbl and 0.3 Bcf in Okume. Removal of one of the wells from the development plan in Okume resulted in reserves decrease of 0.3 MMBbl. Overall, Equatorial Guinea had a decrease in reserves of 1.0 MMBbl and 0.4 Bcf.
- In Mauritania and Senegal, we had a positive revision of 9.7 Bcf due to the optimization of the timing of the Greater Tortue Ahmeyim Phase 1 project. We also had a negative revision of 0.4 MMBbl of condensate based on the incorporation of well test results. We note that the decrease in commodity prices did not result in revisions of estimates.
- In the U.S. Gulf of Mexico, we had a negative reserves revision of 1.8 MMBbl and 2.1 Bcf due to increased watercut at Tornado, production performance at Odd Job and the results of the new well in Marmalard, in addition to commodity price effect of 0.1 MMBbl and 0.1 Bcf, and the net production of 4.9 MMBbl and 4.0 Bcf. Overall, for the year ended December 31, 2023, the U.S. Gulf of Mexico had a reserves decrease of 6.8 MMBbl and 6.2 Bcf.

The revisions in estimates in 2022 are related to:

- In Ghana, we had negative revisions of 14.3 MMBbl of oil and 14.2 Bcf of gas resulting from the conclusion of the Tullow pre-emption transaction in March 2022 in the Jubilee and TEN Fields. Jubilee had a positive revision of 11.0 MMBbl due to positive drilling results and field performance and a negative revision of 3.0 Bcf related to changes in remaining field life, in addition to Jubilee net production of 11.3 MMBbl. TEN had a negative revision of 6.1 MMBbl and 9.6 Bcf due to recent well performance and updated reservoir model forecast, in addition to the net TEN production of 2.0 MMBbl. In Ghana, the increase in commodity prices resulted in a positive revision of 2.2 MMBbl and 7.1 Bcf. The overall decreases in reserves for the year ended December 31, 2022 were 6.6 MMBbl and 2.8 Bcf for Jubilee and 13.9 MMBbl and 16.7 Bcf for TEN.
- In Equatorial Guinea, we had a positive revision of 0.9 MMBbl of oil based on production performance and topsides optimization in Ceiba, offset by net production of 3.7 MMBbl. The increase in commodity prices along with the license extension in Ceiba from 2029 to 2040 and in Okume from 2034 to 2040 resulted in a positive revision of 3.2 MMBbl and 5.2 Bcf. Overall, Equatorial Guinea had an increase in reserves of 0.4 MMBbl and 5.2 Bcf.
- In Mauritania/Senegal, we had additions of 28.1 Bcf due to a field extension that resulted from drilling of production wells. We also had a 0.7 MMBbl negative revision in condensate reserves based on an updated yield estimate. We note that the increase in commodity prices did not result in revisions of estimates.
- In the U.S. Gulf of Mexico, we had a negative revision of 2.1 MMBbl and positive revision of 0.3 Bcf of gas based on recent water breakthrough in Odd Job and Tornado, Kodiak production performance, in addition to the net production of 5.7 MMBbl and 4.0 Bcf. The Winterfell discovery added 2.9 MMBbl and 1.0 Bcf of gas. The purchase of additional interest in the Kodiak field resulted in a positive revision of 0.8 MMBbl. We note the changes in commodity prices in the U.S. Gulf of Mexico were not material. The overall decrease in reserves for the U.S. Gulf of Mexico were 4.1 MMBbl and 2.7 Bcf.

The revisions in estimates in 2021 are related to:

- In Ghana, we had 5.5 MMBbl of positive revisions in estimates (primarily related to the Jubilee Field) related to overall field performance, including positive drilling results on our proved undeveloped well locations and optimized future well locations. We had 8.0 Bcf of positive revisions in estimates in the TEN Field related to the updated reservoir model forecast. The increase in commodity prices resulted in positive revisions in estimates of 4.1 MMBbl of oil reserves and 1.7 Bcf of gas reserves.

- In Equatorial Guinea, we had 3.0 MMBbl of positive revisions in estimates due to overall field performance and positive drilling results and 0.7 MMBbl of positive revisions in estimates due to the increase in commodity prices. We note changes in Equatorial Guinea gas reserves was not material.
- In Mauritania/Senegal, we had 8.2 MMBbl and 590.0 Bcf of positive revisions in proved undeveloped reserve estimates related to the economic status of Phase 1 of the Greater Tortue project due to the project progress and improved commodity prices.
- In the U.S. Gulf of Mexico, we had positive revisions of 0.6 MMBbl and 3.2 Bcf of gas reserves related to strong performance of certain fields across our portfolio. The increase in commodity prices resulted in positive revisions of 3.0 MMBbl and 1.3 Bcf, respectively.

(3) The purchases of minerals-in-place during 2021 is related to our acquisition of additional interests in the Jubilee field and TEN fields offshore Ghana, resulting in total proved oil reserve additions of 38.7 MMBbl and 12.8 MMBbl and total proved gas reserve additions of 7.2 Bcf and 20.1 Bcf, respectively.

(4) Natural gas liquids proved reserves represent an immaterial amount of our total proved reserves. Therefore, we have aggregated natural gas liquids and crude oil/condensate reserves information.

(5) The changes in proved undeveloped reserves in 2023 are related to:

- In Ghana, we converted 21.5 MMbbl of proved undeveloped reserves to proved developed reserves during the year by the drilling of five wells in Greater Jubilee at a cost of approximately $98.0 million as well as approximately $91.3 million in subsea costs. In addition, we spent $40.5 million in drilling costs towards wells that we expect to report as converted proved undeveloped reserves in 2024. Positive drilling results during the year ended December 31, 2023 resulted in an increase in proved undeveloped reserves of 0.6 MMbbl and 0.4 Bcf. In Jubilee, the recognition of gas sales resulted in a proved undeveloped reserves increase of 56.0 Bcf and positive revision of future well forecasts based on improved performance of existing wells resulted in a proved undeveloped reserves increase of 16.7 MMbbl. Changes to the partnership's development work scope and forecasts of planned wells in TEN resulted in proved undeveloped reserves decrease of 4.9 MMbbl and 8.7 Bcf.
- In Equatorial Guinea, during the year ended December 31, 2023, we had a proved developed reserves decrease of 0.3 MMbbl due to removal of one of the planned wells from the Okume drilling plan.
- In Mauritania/ Senegal, we had a proved undeveloped reserves increase of 9.7 Bcf due to optimization of the timing of the Greater Tortue Ahmeyim Phase 1 project. We also had a negative revision of 0.4 MMbbl of condensate based on the testing results of the drilled wells. We spent approximately $259.8 million progressing the Greater Tortue Phase 1 development with first gas for the project targeted in the third quarter of 2024.
- In the U.S. Gulf of Mexico, we had a proved undeveloped reserves decrease of 0.9 MMbbl and 0.9 Bcf. We converted 0.6 MMbbl and 0.8 Bcf with the drilling of one well in Marmalard at a cost of $16.5 million, in addition to a negative revision of 0.2 MMbbl and 0.1 Bcf due to slight changes to the recovery of several fields. In addition, we spent approximately $49.0 million on the Odd Job subsea pump installation and approximately $67.5 million towards the development of the Winterfell Field.

The changes in proved undeveloped reserves in 2022 are related to:

- In Ghana, we converted 4.6 MMBbl of oil in Jubilee of proved undeveloped reserves to proved developed reserves during the year by drilling three wells at a cost of approximately $75.1 million. In TEN, we converted 5.1 MMBbl and 4.1 Bcf of gas of proved undeveloped reserves to proved developed reserves during the year by drilling one well at a cost of approximately $13.6 million. We had a decrease in proved undeveloped reserves of 4.3 MMBbl in Jubilee and 3.0 MMBbl and 3.3 Bcf in TEN related to the sale of minerals-in-place during 2022. The Jubilee Field had an increase in proved undeveloped reserves of 4.0 MMBbl related to optimization of future drilling. The TEN Field had a proved undeveloped reserves increase of 1.4 MMBbl and 4.1 Bcf related to an updated plan of development. The overall proved undeveloped reserves decreased by 5.0 MMBbl in Jubilee and by 6.7 MMBbl and 3.3 Bcf in TEN.
- In Equatorial Guinea, during the year ended December 31, 2022, Equatorial Guinea had no material changes in proved undeveloped reserves.
- In Mauritania/Senegal, we had a proved undeveloped reserves increase of 28.1 Bcf due to a field extension that resulted from drilling of production wells. We also had a 0.7 MMBbl negative revision in condensate reserves based on an updated yield estimate.
- In the U.S. Gulf of Mexico, we had a proved undeveloped reserves increase of 1.0 MMBbl and 1.8 Bcf due based on an updated plans of development in the Odd Job, Marmalard, and Big Bend fields. We converted 1.6 MMBbl and 2.2 Bcf from proved undeveloped by drilling one well in Kodiak at a cost of $13.6 million. The Winterfell discovery added 2.9 MMBbl and 1.0 Bcf of gas of proved undeveloped reserves. We added 0.2 MMBbl of proved undeveloped

reserves related to our purchase of minerals-in-place during 2022 in the Kodiak field. The overall proved undeveloped reserves in the U.S. Gulf of Mexico increased by 2.4 MMBbl and 0.6 Bcf.

The changes in proved undeveloped reserves in 2021 are related to:

- In Ghana, Jubilee had a proved undeveloped reserves increase of 17.8 MMBbl related to optimization of future drilling. Related to our purchases of minerals-in-place during 2021, we added 28.5 MMBbl and 4.7 Bcf of proved undeveloped reserves. We converted 20.7 MMBbl of proved undeveloped reserves to proved developed reserves during the year by drilling three wells at a cost of $34.1 million.
- In Equatorial Guinea, during the year ended December 31, 2021, Equatorial Guinea had a PUD increase of 2.9 MMBbl related to adding a future development well and optimizing future development plans in Equatorial Guinea. We converted 1.8 MMBbl of proved undeveloped reserves to proved developed reserves during the year by drilling two wells and replacing certain subsea infrastructure at a cost of $35.6 million.
- In the U.S. Gulf of Mexico, we had a proved undeveloped reserves increase of 3.5 MMBbl of oil reserves and 6.3 Bcf of gas reserves related to adding a future development well and optimizing future development plans. We converted 1.8 MMBbl and 1.8 Bcf of gas proved undeveloped reserves to proved developed reserves through drilling of one well in Tornado at a cost of $19.0 million.

Net proved reserves were calculated utilizing the twelve month unweighted arithmetic average of the first-day-of-the-month oil price for each month based on the respective benchmark price in the period January through December 2023. The average price is adjusted for crude handling, transportation fees, quality, and a regional price differential.

Proved oil and gas reserves are defined by the SEC Rule 4.10(a) of Regulation S-X as those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recovered under current economic conditions, operating methods, and government regulations. Inherent uncertainties exist in estimating proved reserve quantities, projecting future production rates and timing of development expenditures.

Capitalized Costs Related to Oil and Gas Activities

The following table presents aggregate capitalized costs related to oil and gas activities:

	Ghana	Equatorial Guinea	Mauritania / Senegal	U.S. Gulf of Mexico	Other	Kosmos Total
			(In millions)			
As of December 31, 2023						
Unproved properties	$ —	$ 92	$ 125	$ 192	$ 14	$ 423
Proved properties	3,769	588	1,663	1,580	$ —	7,600
	3,769	680	1,788	1,772	14	8,023
Accumulated depletion	(2,733)	(256)	—	(880)	—	(3,869)
Net capitalized costs	$ 1,036	$ 424	$ 1,788	$ 892	$ 14	$ 4,154
As of December 31, 2022						
Unproved properties	$ —	$ 85	$ 114	$ 130	$ 13	$ 342
Proved properties	3,705	526	1,282	1,440	—	6,953
	3,705	611	1,396	1,570	13	7,295
Accumulated depletion	(2,502)	(214)	—	(741)	—	(3,457)
Net capitalized costs	$ 1,203	$ 397	$ 1,396	$ 829	$ 13	$ 3,838

Costs Incurred in Oil and Gas Activities

The following tables reflects total costs incurred, both capitalized and expensed, for oil and gas property acquisition, exploration, and development activities for the year.

	Ghana	Equatorial Guinea	Mauritania / Senegal	U.S. Gulf of Mexico	Other(1)	Kosmos Total
			(In millions)			
Year ended December 31, 2023						
Property acquisition:						
Unproved	$ —	$ 1	$ —	$ 2	$ —	$ 3
Proved	—	—	—	—	—	—
Exploration	1	10	3	67	6	87
Development	287	68	404	146	—	905
Total costs incurred	$ 288	$ 79	$ 407	$ 215	$ 6	$ 995
Year ended December 31, 2022						
Property acquisition:						
Unproved	$ —	$ 2	$ —	$ 19	$ —	$ 21
Proved	—	7	—	27	—	34
Exploration	15	9	74	31	5	134
Development(3)(5)	226	37	486	17	—	766
Total costs incurred	$ 241	$ 55	$ 560	$ 94	$ 5	$ 955
Year ended December 31, 2021						
Property acquisition:						
Unproved	$ —	$ 1	$ —	$ (2)	$ (1)	$ (2)
Proved(2)	718	1	—	—	—	719
Exploration	—	8	16	60	6	90
Development(4)	112	79	333	46	—	570
Total costs incurred	$ 830	$ 89	$ 349	$ 104	$ 5	$ 1,377

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(1) Includes Africa (excluding Ghana, Equatorial Guinea, Mauritania and Senegal), Europe and South America.

(2) Includes $718.2 million of oil and gas properties acquired as a result of the purchase price allocation of the estimated fair value of identifiable assets acquired and liabilities assumed in the acquisition of additional interests in Ghana discussed in “Note 3—Acquisitions and Divestitures.”

(3) Includes $132.4 million of capitalized oil and gas properties settled against our Long-term receivable from BP Operator in Mauritania and Senegal discussed in “Note 4—Joint Interest Billings and Long-term Receivables.”

(4) Includes $67.8 million of capitalized oil and gas properties settled against our Long-term receivable from BP Operator in Mauritania and Senegal discussed in “Note 4—Joint Interest Billings and Long-term Receivables.”

(5) Excludes $66.2 million reduction of capitalized asset retirement costs resulting from the extension of the Block G licenses in Equatorial Guinea in May 2022.

Standardized Measure for Discounted Future Net Cash Flows

The following table provides projected future net cash flows based on the twelve month unweighted arithmetic average of the first-day-of-the-month oil price for Brent crude in the period January through December 2023. The average price is adjusted for crude handling, transportation fees, quality, and a regional price differential.

Because prices used in the calculation are average prices for that year, the standardized measure could vary significantly from year to year based on market conditions that occur.

The projection should not be interpreted as representing the current value to Kosmos. Material revisions to estimates of proved reserves may occur in the future; development and production of the reserves may not occur in the periods assumed; actual prices realized are expected to vary significantly from those used; and actual costs may vary. Kosmos' investment and operating decisions are not based on the information presented, but on a wide range of reserve estimates that include probable as well as proved reserves and on a wide range of different price and cost assumptions.

The standardized measure is intended to provide a better means to compare the value of Kosmos' proved reserves at a given time with those of other oil producing companies than is provided by comparing raw proved reserve quantities.

	Ghana	Equatorial Guinea	Mauritania / Senegal	U.S. Gulf of Mexico	Total
			(In millions)		
At December 31, 2023					
Future cash inflows	$ 8,200	$ 1,928	$ 5,363	$ 1,538	$ 17,029
Future production costs	(1,586)	(869)	(2,725)	(297)	(5,477)
Future development and abandonment costs	(1,176)	(561)	(679)	(376)	(2,792)
Future tax expenses	(1,780)	(284)	(6)	(47)	(2,117)
Future net cash flows	3,658	214	1,953	818	6,643
10% annual discount for estimated timing of cash flows	(885)	138	(1,172)	(104)	(2,023)
Standardized measure of discounted future net cash flows	$ 2,773	$ 352	$ 781	$ 714	$ 4,620
At December 31, 2022					
Future cash inflows	$ 10,076	$ 2,507	$ 6,419	$ 2,532	$ 21,534
Future production costs	(1,586)	(877)	(2,696)	(359)	(5,518)
Future development and abandonment costs	(1,395)	(610)	(753)	(489)	(3,247)
Future tax expenses	(2,399)	(465)	(340)	(190)	(3,394)
Future net cash flows	4,696	555	2,630	1,494	9,375
10% annual discount for estimated timing of cash flows	(1,394)	43	(1,498)	(365)	(3,214)
Standardized measure of discounted future net cash flows	$ 3,302	$ 598	$ 1,132	$ 1,129	$ 6,161
At December 31, 2021					
Future cash inflows	$ 8,308	$ 1,661	$ 4,314	$ 1,981	$ 16,264
Future production costs	(2,079)	(621)	(2,853)	(334)	(5,887)
Future development and abandonment costs	(1,640)	(478)	(822)	(284)	(3,224)
Future tax expenses	(1,546)	(307)	(43)	(117)	(2,013)
Future net cash flows	3,043	255	596	1,246	5,140
10% annual discount for estimated timing of cash flows	(983)	37	(671)	(262)	(1,879)
Standardized measure of discounted future net cash flows	$ 2,060	$ 292	$ (75)	$ 984	$ 3,261

Changes in the Standardized Measure for Discounted Cash Flows

	Ghana	Equatorial Guinea	Mauritania / Senegal	U.S. Gulf of Mexico	Total
			(In millions)		
Balance at December 31, 2020	$ 364	$ 27	$ —	$ 573	$ 964
Purchase of minerals in place	981	—	—	—	981
Sales and transfers 2021	(493)	(167)	—	(325)	(985)
Extensions and discoveries	—	—	—	—	—
Net changes in prices and costs	1,232	479	(75)	602	2,238
Previously estimated development costs incurred during the period	91	73	—	42	206
Net changes in development costs	(187)	(124)	—	(38)	(349)
Revisions of previous quantity estimates	367	128	—	153	648
Net changes in tax expenses	(421)	(146)	—	(74)	(641)
Accretion of discount	53	12	—	58	123
Changes in timing and other	73	10	—	(7)	76
Balance at December 31, 2021	$ 2,060	$ 292	$ (75)	$ 984	$ 3,261
Purchase of minerals in place	—	—	—	47	47
Sales of minerals in place	(243)	—	—	—	(243)
Sales and transfers 2022	(1,144)	(256)	—	(442)	(1,842)
Extensions and discoveries	—	—	171	46	217
Net changes in prices and costs	2,340	422	868	673	4,303
Previously estimated development costs incurred during the period	207	28	387	59	681
Net changes in development costs	(119)	(8)	(150)	(94)	(371)
Revisions of previous quantity estimates	645	192	(9)	(117)	711
Net changes in tax expenses	(882)	(143)	(77)	(87)	(1,189)
Accretion of discount	271	52	—	106	429
Changes in timing and other	167	19	17	(46)	157
Balance at December 31, 2022	$ 3,302	$ 598	$ 1,132	$ 1,129	$ 6,161
Purchase of minerals in place	—	—	—	—	—
Sales of minerals in place	—	—	—	—	—
Sales and transfers 2023	(866)	(153)	—	(271)	(1,290)
Extensions and discoveries	248	—	—	—	248
Net changes in prices and costs	(1,582)	(379)	(444)	(464)	(2,869)
Previously estimated development costs incurred during the period	277	62	260	138	737
Net changes in development costs	(25)	(19)	(178)	(44)	(266)
Revisions of previous quantity estimates	734	74	10	(112)	706
Net changes in tax expenses	179	77	95	142	493
Accretion of discount	504	93	—	130	727
Changes in timing and other	2	(1)	(94)	66	(27)
Balance at December 31, 2023	$ 2,773	$ 352	$ 781	$ 714	$ 4,620

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) was performed under the supervision and with the participation of the Company's management, including our Chief Executive Officer and Chief Financial Officer. This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the SEC reports we file or submit under the Exchange Act is accurate, complete and timely. However, 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. The design of a control system must reflect the fact that there are resource constraints, and the benefit of controls must be considered relative to their costs. Consequently, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. Based upon this evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2023, in ensuring that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, including that such information is accumulated and communicated to the Company's management, including our Chief Executive Officer and our Chief Financial Officer, to allow timely decisions regarding required disclosure.

Evaluation of Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during our most recent fiscal quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control has been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external purposes in accordance with U.S. generally accepted accounting principles. All internal control systems have inherent limitations, including the possibility of human error and the possible circumvention of or overriding of controls. The design of an internal control system is also based in part upon assumptions and judgments made by management. As a result, even an effective system of internal controls can provide no more than reasonable assurance with respect to the fair presentation of financial statements and the processes under which they were prepared. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that internal control may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, we assessed the effectiveness of our internal control over financial reporting as of the end of the period covered by this report based on the framework in "Internal Control—Integrated Framework (2013)" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, our Chief Executive Officer and our Chief Financial Officer concluded that our internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of our financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

Ernst & Young LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this annual report on Form 10-K, has issued an attestation report on the effectiveness of internal control over financial reporting as of December 31, 2023 which is included in "Item 8. Financial Statements and Supplementary Data."

Item 9B. Other Information

Disclosures Required Pursuant to Section 13(r) of the Securities Exchange Act of 1934

Not applicable.

Other

None.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated herein by reference to the 2024 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2023.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2024 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2023.

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

The information required by this item is incorporated herein by reference to the 2024 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2023.

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

The information required by this item is incorporated herein by reference to the 2024 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2023.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the 2024 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2023.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) The following documents are filed as part of this report:

(1) Financial statements

The financial statements filed as part of the Annual Report on Form 10-K are listed in the accompanying index to consolidated financial statements in Item 8. Financial Statements and Supplementary Data.

(2) Financial statement schedules

Schedule I—Condensed Parent Company Financial Statements

Under the terms of agreements governing the indebtedness of subsidiaries of Kosmos Energy Ltd. for 2023, 2022 and 2021 (collectively “KEL,” the “Parent Company”), such subsidiaries may be restricted from making dividend payments, loans or advances to KEL. Schedule I of Article 5-04 of Regulation S-X requires the condensed financial information of the Parent Company to be filed when the restricted net assets of consolidated subsidiaries exceed 25 percent of consolidated net assets as of the end of the most recently completed fiscal year.

The following condensed parent-only financial statements of KEL have been prepared in accordance with Rule 12-04, Schedule I of Regulation S-X and included herein. The Parent Company’s 100% investment in its subsidiaries has been recorded using the equity basis of accounting in the accompanying condensed parent-only financial statements. The condensed financial statements should be read in conjunction with the consolidated financial statements of Kosmos Energy Ltd. and subsidiaries and notes thereto.

The terms “Kosmos,” the “Company,” and similar terms refer to Kosmos Energy Ltd. and its wholly-owned subsidiaries, unless the context indicates otherwise. Certain prior period amounts have been reclassified to conform with the current year presentation. Such reclassifications had no impact on our reported net income, current assets, total assets, current liabilities, total liabilities or shareholders equity.

KOSMOS ENERGY LTD.

CONDENSED PARENT COMPANY BALANCE SHEETS

(In thousands, except share data)

	December 31,	
	2023	2022
Assets		
Current assets:		
Cash and cash equivalents	$ 275	$ 2,286
Derivatives receivable - related party	—	413
Prepaid expenses and other	752	1,051
Total current assets	1,027	3,750
Investment in subsidiaries at equity	2,683,656	2,403,785
Deferred financing costs, net of accumulated amortization of $15,583 and $13,263 at December 31, 2023 and December 31, 2022, respectively	2,320	4,640
Restricted cash	305	305
Long-term deferred tax asset	12,050	461
Total assets	$ 2,699,358	$ 2,412,941
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable	$ 12	$ 14
Accounts payable to subsidiaries	152,679	114,312
Accrued liabilities	27,650	27,500
Total current liabilities	180,341	141,826
Long-term debt, net	1,486,680	1,483,267
Shareholders' equity:		
Preference shares, $0.01 par value; 200,000,000 authorized shares; zero issued at December 31, 2023 and December 31, 2022	—	—
Common stock, $0.01 par value; 2,000,000,000 authorized shares; 504,392,980 and 500,161,421 issued at December 31, 2023 and December 31, 2022, respectively	5,044	5,002
Additional paid-in capital	2,536,621	2,505,694
Accumulated deficit	(1,272,321)	(1,485,841)
Treasury stock, at cost, 44,263,269 shares at December 31, 2023 and 2022, respectively	(237,007)	(237,007)
Total shareholders' equity	1,032,337	787,848
Total liabilities and shareholders' equity	$ 2,699,358	$ 2,412,941

KOSMOS ENERGY LTD.

CONDENSED PARENT COMPANY STATEMENTS OF OPERATIONS

(In thousands)

	Years Ended December 31,		
	2023	2022	2021
Revenues and other income:			
Oil and gas revenue	$ —	$ —	$ —
Other income—related party	—	75,740	20,307
Total revenues and other income	—	75,740	20,307
Costs and expenses:			
General and administrative	52,279	44,180	38,810
General and administrative recoveries—related party	(6,048)	(3,772)	79
Interest and other financing costs, net	122,773	123,247	98,649
Interest and other financing costs, net—related party	—	—	(2,446)
Derivatives, net	—	75,740	20,307
Other expenses, net	131	17	(61)
Equity in (earnings) losses of subsidiaries	(370,729)	(415,546)	(57,195)
Total costs and expenses	(201,594)	(176,134)	98,143
Income (loss) before income taxes	201,594	251,874	(77,836)
Income tax expense (benefit)	(11,926)	25,323	—
Net income (loss)	$ 213,520	$ 226,551	$ (77,836)

KOSMOS ENERGY LTD.

CONDENSED PARENT COMPANY STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31,		
	2023	2022	2021
Operating activities			
Net income (loss)	$ 213,520	$ 226,551	$ (77,836)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Equity in (earnings) losses of subsidiaries	(370,729)	(415,546)	(57,195)
Equity-based compensation	42,693	34,546	31,651
Depreciation and amortization	6,588	6,359	5,638
Deferred income taxes	(11,589)	18,034	—
Other income—related party	413	(4,353)	6,582
Change in fair value on derivatives	—	75,741	20,307
Cash settlements on derivatives	—	(70,327)	(28,363)
Loss on extinguishment of debt	—	192	4,403
Changes in assets and liabilities:			
Decrease in receivables	87	306	134
(Increase) decrease in prepaid expenses and other	299	(94)	(49)
Decrease due to/from related party	37,765	33,214	218,008
Increase (decrease) in accounts payable and accrued liabilities	60	(4,159)	18,003
Net cash provided by (used in) operating activities	(80,893)	(99,536)	141,283
Investing activities			
Investment in subsidiaries	90,858	104,676	(1,001,494)
Net cash provided by (used in) investing activities	90,858	104,676	(1,001,494)
Financing activities			
Borrowings under long-term debt	—	—	100,000
Payments on long-term debt	—	—	(200,000)
Net proceeds from issuance of senior notes	—	—	839,375
Net proceeds from issuance of common stock	—	—	136,006
Dividends	(166)	(655)	(512)
Other financing costs	(11,810)	(8,892)	(9,131)
Net cash provided by (used in) financing activities	(11,976)	(9,547)	865,738
Net increase (decrease) in cash and cash equivalents	(2,011)	(4,407)	5,527
Cash, cash equivalents and restricted cash at beginning of period	2,591	6,998	1,471
Cash, cash equivalents and restricted cash at end of period	$ 580	$ 2,591	$ 6,998

Schedule II

Kosmos Energy Ltd.

Valuation and Qualifying Accounts

For the Years Ended December 31, 2023, 2022 and 2021

Description	Balance January 1,	Additions: Charged to Costs and Expenses	Additions: Charged To Other Accounts	Deductions From Reserves	Balance December 31,
2023					
Allowance for credit losses	$ 7,011	$ 2,842	$ (6)	$ —	$ 9,847
Allowance for deferred tax assets	$ 312,727	$ 20,924	$ —	$ —	$ 333,651
2022					
Allowance for credit losses	$ 5,189	$ 2,509	$ (687)	$ —	$ 7,011
Allowance for deferred tax assets	$ 318,343	$ (5,616)	$ —	$ —	$ 312,727
2021					
Allowance for credit losses	$ 5,675	$ 1,019	$ (1,505)	$ —	$ 5,189
Allowance for deferred tax assets	$ 288,288	$ 30,055	$ —	$ —	$ 318,343

Schedules other than Schedule I and Schedule II have been omitted because they are not applicable or the required information is presented in the consolidated financial statements or the notes to consolidated financial statements.

(3) Exhibits

See “Index to Exhibits” on page 139 for a description of the exhibits filed as part of this report.

Item 16. Form 10-K Summary

None

SIGNATURES

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

KOSMOS ENERGY LTD.

Date: February 26, 2024	By:	/s/ NEAL D. SHAH
		Neal D. Shah *Senior Vice President and Chief Financial Officer*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ ANDREW G. INGLIS Andrew G. Inglis	Chairman of the Board of Directors and Chief Executive Officer (Principal Executive Officer)	February 26, 2024
/s/ NEAL D. SHAH Neal D. Shah	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2024
/s/ RONALD W. GLASS Ronald W. Glass	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 26, 2024
/s/ ROY A. FRANKLIN Roy A. Franklin	Director	February 26, 2024
/s/ DEANNA L. GOODWIN Deanna L. Goodwin	Director	February 26, 2024
/s/ ADEBAYO O. OGUNLESI Adebayo O. Ogunlesi	Director	February 26, 2024
/s/ STEVEN M. STERIN Steven M. Sterin	Director	February 26, 2024
/s/ MARIA M HANSSEN Maria M. Hanssen	Director	February 26, 2024
/s/ SIR JOHN GRANT Sir John Grant	Director	February 26, 2024
/s/ J. MIKE STICE J. Mike Stice	Director	February 26, 2024

INDEX OF EXHIBITS

Exhibit Number	Description of Document
	Governing Documents
3.1	Certificate of Incorporation of the Company (filed as Exhibit 3.1 to the Company’s Form 8-K12g-3 filed December 28, 2018 (File No. 000-56014), and incorporated herein by reference).
3.2	Amended and Restated Bylaws of the Company (filed as Exhibit 3.1 to the Company’s Form 8-K filed March 15, 2022 (File No. 001-35167), and incorporated herein by reference).
4.1	Form of Common Stock Certificate (filed as Exhibit 4.1 to the Company’s Form 8-K12g-3 filed December 28, 2018 (File No. 000-56014), and incorporated herein by reference).
4.2	Description of the Company's Capital Stock (filed as Exhibit 4.2 to the Company's Annual Report on Form 10-K for the year ended December 31, 2019, and incorporated herein by reference.)
	Operating Agreements
	Certain of the agreements listed below have been filed pursuant to the Company’s voluntary compliance with international transparency standards and are not material contracts as such term is used in Item 601(b)(10) of Regulation S-K.
	Ghana
10.1	Petroleum Agreement in respect of West Cape Three Points Block Offshore Ghana dated July 22, 2004 among the GNPC, Kosmos Ghana and the E.O. Group (filed as Exhibit 10.1 to the Company’s Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.2	Joint Operating Agreement in respect of West Cape Three Points Block Offshore Ghana dated July 27, 2004 between Kosmos Ghana and E.O. Group (filed as Exhibit 10.2 to the Company’s Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.3	Petroleum Agreement in respect of the Deepwater Tano Contract Area dated March 10, 2006 among GNPC, Tullow Ghana, Sabre and Kosmos Ghana (filed as Exhibit 10.3 to the Company’s Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.4	Joint Operating Agreement in respect of the Deepwater Tano Contract Area, Offshore Ghana dated August 14, 2006, among Tullow Ghana, Sabre Oil and Gas Limited, and Kosmos Ghana (filed as Exhibit 10.4 to the Company’s Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.5	Unitization and Unit Operating Agreement covering the Jubilee Field Unit located offshore the Republic of Ghana dated July 13, 2009, among GNPC, Tullow, Kosmos Ghana, Anadarko WCTP, Sabre and E.O. Group (filed as Exhibit 10.6 to the Company’s Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.6	Settlement Agreement, dated December 18, 2010 among Kosmos Ghana, Ghana National Petroleum Corporation and the Government of the Republic of Ghana (filed as Exhibit 10.32 to the Company’s Registration Statement on Form S-1/A filed April 14, 2011 (File No. 333-171700), and incorporated herein by reference).
	Sao Tome and Principe
10.7	Production Sharing Contract relating to Block 5 Offshore Sao Tome between the Democratic Republic of Sao Tome and Principe and Equator Exploration STP Block 5 Limited dated April 18, 2012 (filed as Exhibit 10.1 to the Company’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, and incorporated herein by reference).
10.8	Amendment No. 1, dated November 24, 2014, to the Production Sharing Contract relating to Block 5 Offshore Sao Tome between the Democratic Republic of Sao Tome and Principe and Equator Exploration STP Block 5 Limited dated April 18, 2012 (filed as Exhibit 10.2 to the Company’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, and incorporated herein by reference).
10.9	Amendment No. 2, dated September 15, 2015, to the Production Sharing Contract relating to Block 5 Offshore Sao Tome between the Democratic Republic of Sao Tome and Principe and Equator Exploration STP Block 5 Limited dated April 18, 2012 (filed as Exhibit 10.3 to the Company’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, and incorporated herein by reference).
10.10	Amendment No. 3, dated February 19, 2016, to the Production Sharing Contract relating to Block 5 Offshore Sao Tome between the Democratic Republic of Sao Tome and Principe, Equator Exploration STP Block 5 Limited and Kosmos Energy Sao Tome and Principe dated April 18, 2012 (filed as Exhibit 10.5 to the Company’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, and incorporated herein by reference).
	Senegal

Exhibit Number	Description of Document
10.11	Hydrocarbon Exploration and Production Sharing Contract for the Cayar Offshore Profond between the Republic of Senegal and Petro-Tim Limited and Societe des Petroles du Senegal dated January 17, 2012 (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2014, and incorporated herein by reference).
10.12	Hydrocarbon Exploration and Production Sharing Contract for the Saint Louis Offshore Profond between the Republic of Senegal and Petro-Tim Limited and Societe des Petroles du Senegal dated January 17, 2012 (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2014, and incorporated herein by reference).
10.13	Sale and Purchase Agreement relating to the sale and purchase of shares in Kosmos BP Senegal Limited (formerly Normandy Ventures Limited) between BP Indonesia Oil Terminal Investment Limited and Kosmos Energy Senegal dated December 15, 2016 (filed as Exhibit 10.31 to the Company's Annual Report on Form 10-K of the year ended December 31, 2016, and incorporated herein by reference).
	Mauritania
10.14	Exploration and Production Contract between The Islamic Republic of Mauritania and Kosmos Energy Mauritania (Bloc C8) dated April 5, 2012 (filed as Exhibit 10.17 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.15	Exploration and Production Contract between The Islamic Republic of Mauritania and BP Mauritania Investments Limited, Kosmos Energy Mauritania, and Societe Mauritanienne Des Hydrocarbures (BirAllah) dated November 7, 2022 (filed as Exhibit 10.16 to the Company's Annual Report on Form 10-K for the year ended December 31, 2022, and incorporated herein by reference).
	Equatorial Guinea
10.16	Share Sale and Purchase Agreement relating to the sale and purchase of shares in Hess International Petroleum, Inc. between Hess Equatorial Guinea Investments Limited, Hess Corporation, Kosmos Energy Equatorial Guinea, Kosmos Energy Operating and Trident Energy E.G. Operations, Ltd. dated October 23, 2017 (filed as Exhibit 10.43 to the Company's Annual Report on Form 10-K of the year ended December 31, 2017, and incorporated herein by reference).
10.17	Production Sharing Contract relating to Block G Offshore Republic of Equatorial Guinea between the Republic of Equatorial Guinea and Triton Equatorial Guinea, Inc. dated March 26, 1997 (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, and incorporated herein by reference).
10.18	Amendment No. 1, dated January 1, 2000, to the Production Sharing Contract relating to Block G Offshore Republic of Equatorial Guinea between Triton Equatorial Guinea, Inc., Energy Africa Equatorial Guinea Limited, and the Republic of Equatorial Guinea represented by the Ministry of Mines and Energy (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, and incorporated herein by reference).
10.19	Amendment No. 2, dated December 15, 2005, to the Production Sharing Contract relating to Block G Offshore Republic of Equatorial Guinea between Amerada Hess Equatorial Guinea, Energy Africa Equatorial Guinea Limited, and the Republic of Equatorial Guinea represented by the Ministry of Mines, Industry and Energy (filed as Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, and incorporated herein by reference).
10.20	Amendment No. 3, dated October 22, 2017, to the Production Sharing Contract relating to Block G Offshore Republic of Equatorial Guinea between Hess Equatorial Guinea, Tullow Equatorial Guinea Limited, and the Republic of Equatorial Guinea represented by the Ministry of Mines and Hydrocarbons (filed as Exhibit10.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, and incorporated herein by reference).
10.21*	Amendment No. 4, dated February 1, 2019, to the Production Sharing Contract relating to Block G Offshore Republic of Equatorial Guinea between Kosmos-Trident Equatorial Guinea, Inc., Kosmos Equatorial Guinea, Inc., Tullow Equatorial Guinea Limited, and the Republic of Equatorial Guinea represented by the Ministry of Mines and Hydrocarbons.
10.22*	Amendment No. 5, dated May 5, 2022, to the Production Sharing Contract relating to Block G Offshore Republic of Equatorial Guinea between Trident Equatorial Guinea, Inc., Kosmos Equatorial Guinea, Inc., Panoro Equatorial Guinea Limited, Guinea Ecuatorial de Petroleos and the Republic of Equatorial Guinea represented by the Ministry of Mines and Hydrocarbons.
10.23	Production Sharing Contract relating to Block EG-21 Offshore Republic of Equatorial Guinea between the Republic of Equatorial Guinea, Guinea Ecuatorial de Petroleos and Kosmos Energy Equatorial Guinea dated October 10, 2017 (filed as Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, and incorporated herein by reference).

Exhibit Number	Description of Document
10.24	Production Sharing Contract relating to Block S Offshore Republic of Equatorial Guinea between the Republic of Equatorial Guinea, Guinea Ecuatorial de Petroleos and Kosmos Energy Equatorial Guinea dated October 10, 2017 (filed as Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, and incorporated herein by reference).
10.25	Production Sharing Contract relating to Block EG-24 Offshore Equatorial Guinea between the Republic of Equatorial Guinea, Guinea Ecuatorial de Petroleos and Ophir Equatorial Guinea (EG-24) Limited dated October 2017 (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018, and incorporated herein by reference).
10.26	Production Sharing Contract relating to Block EG-01 Offshore Republic of Equatorial Guinea between the Republic of Equatorial Guinea, Guinea Ecuatorial de Petroleos, Panoro EG Exploration Limited and Kosmos Energy Equatorial Guinea dated February 17, 2023 (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2023, and incorporated herein by reference).
	Greater Tortue Ahmeyim
10.27††	Agreement for a Long Term Sale and Purchase of LNG, dated February 11, 2020, between LA Societe Mauritanienne des Hydrocarbures et de Patrimoine Minier, BP Mauritania Investments Limited, Kosmos Energy Investments Limited, La Societe des Petroles du Senegal, BP Senegal Investments Limited, Kosmos Energy Investments Senegal Limited and BP Gas Marketing Limited (filed as Exhibit 10.46 to the Company's Annual Report on Form 10-K for the year ended December 31, 2019, and incorporated herein by reference).
	Financing Agreements
10.28	Indenture, dated as of April 4, 2019, among the Company, the guarantors names therein, Wilmington Trust, National Association, as trustee, transfer agent, registrar and paying agent and Banque Internationale à Luxembourg S.A., as Luxembourg listing agent, transfer agent and paying agent (including the Form of Notes) (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K filed April 4, 2019 (File No. 001-35167), and incorporated herein by reference).
10.29	Deed of Amendment and Restatement relating to the Facility Agreement, dated February 5, 2018 among Kosmos Energy Finance International, Kosmos Energy Operating, Kosmos Energy International, Kosmos Energy Development, Kosmos Energy Ghana HC, Kosmos Energy Senegal, Kosmos Energy Mauritania, Kosmos Energy Equatorial Guinea, Kosmos Energy Investments Senegal Limited, BNP Paribas and Standard Chartered Bank (filed as Exhibit 10.10 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, and incorporated herein by reference).
10.30	Amended and Restated Revolving Credit Facility Agreement, dated August 6, 2018, among Kosmos Energy Ltd., as Original Borrower, certain of its subsidiaries listed therein, as Guarantors, ING Bank N.V., as Facility Agent, Crédit Agricole Corporate and Investment Bank, as Security and Intercreditor Agent, and the financial institutions listed therein, as Lenders (filed as Exhibit 1.1 to the Company's Current Report on Form 8-K filed August 7, 2018 (File No. 001-35167), and incorporated herein by reference).
10.31††	Senior Secured Term Loan Credit Agreement, dated September 30, 2020, among Kosmos Energy Ltd., Kosmos Energy GoM Holdings, LLC, Kosmos Energy Gulf of Mexico Operations, LLC, the Other Guarantors named therein, the Initial Lenders named therein and CLMG CORP, as Term Loan Collateral Agent and Administrative Agent (filed as Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2020, and incorporated herein by reference).
10.32	Indenture dated March 4, 2021 among the Company, the guarantors named therein, Wilmington Trust, National Association, as trustee, paying agent, transfer agent and registrar, and Banque Internationale à Luxembourg S.A., as Luxembourg listing agent, Luxembourg paying agent and Luxembourg transfer agent. (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K filed March 4, 2021 (File No. 001-35167), and incorporated herein by reference).
10.33	Amended and Restated Facility Agreement, effective May 12, 2021 among Kosmos Energy Finance International, Kosmos Energy Operating, Kosmos Energy International, Kosmos Energy Development, Kosmos Energy Ghana HC, Kosmos Energy Equatorial Guinea, ABSA Bank Limited, Credit Agricole Corporate and Investment Bank, ING Belgium SA/NV, Natixis, N.B.S.A Limited, Societe Generale, London Branch, The Standard Bank of South Africa Limited, Isle of Man Branch, Standard Chartered Bank, and SMBC Bank International PLC (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2021, and incorporated herein by reference).
10.34	Indenture dated October 13, 2021 among Kosmos Energy Ltd., the guarantors named therein and Wilmington Trust, National Association, as trustee, paying agent, transfer agent and registrar (filed as Exhibit 1.1 to the Company's Current Report on Form 8-K filed October 13, 2021 (File No. 001-35167), and incorporated herein by reference).
10.35	Indenture dated October 26, 2021 among Kosmos Energy Ltd., the guarantors named therein, Wilmington Trust, National Association, as trustee, paying agent, transfer agent and registrar, and Banque Internationale à Luxembourg S.A., as Luxembourg listing agent, Luxembourg paying agent and Luxembourg transfer agent (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K filed October 26, 2021 (File No. 001-35167), and incorporated herein by reference).

Exhibit Number	Description of Document
10.36	Supplemental Indenture dated February 25, 2022 among Kosmos Energy Ltd., the guarantors named therein and, Wilmington Trust, National Association, as trustee, paying agent, transfer agent and registrar (filed as Exhibit 10.56 to the Company's Annual Report on Form 10-K for the year ended December 31, 2021, and incorporated herein by reference).
10.37	Revolving Credit Facility Agreement, dated March 31, 2022, among Kosmos Energy Ltd., as Original Borrower, certain of its subsidiaries listed therein, as Guarantors, ING Bank N.V., as Facility Agent, Crédit Agricole Corporate and Investment Bank, as Security and Intercreditor Agent, and the financial institutions listed therein, as Lenders (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2022, and incorporated herein by reference).
10.38	Amended and Restated Facility Agreement, amended as of November 23, 2022, among Kosmos Energy Finance International, Kosmos Energy Operating, Kosmos Energy International, Kosmos Energy Development, Kosmos Energy Ghana HC, Kosmos Energy Equatorial Guinea, Kosmos Equatorial Guinea, Inc., Kosmos International Petroleum, Inc., ABSA Bank Limited, Credit Agricole Corporate and Investment Bank, ING Belgium SA/NV, Natixis, N.B.S.A Limited, Societe Generale, London Branch, The Standard Bank of South Africa Limited, Isle of Man Branch, Standard Chartered Bank, and SMBC Bank International PLC (filed as Exhibit 10.37 to the Company's Annual Report on Form 10-K for the year ended December 31, 2022, and incorporated herein by reference).
10.39	Revolving Credit Facility Agreement, amended as of November 23, 2022, among Kosmos Energy Ltd., as Original Borrower, certain of its subsidiaries listed therein, as Guarantors, The Standard Bank of South Africa Limited, as Facility Agent, Crédit Agricole Corporate and Investment Bank, as Security and Intercreditor Agent, and the financial institutions listed therein, as Lenders (filed as Exhibit 10.38 to the Company's Annual Report on Form 10-K for the year ended December 31, 2022, and incorporated herein by reference).
10.40	Amended and Restated Facility Agreement, amended as of October 19, 2023, among Kosmos Energy Finance International, Kosmos Energy Operating, Kosmos Energy International, Kosmos Energy Development, Kosmos Energy Ghana HC, Kosmos Energy Equatorial Guinea, Kosmos Energy Ghana Investments, Kosmos Energy Ghana Holdings Limited, Kosmos Equatorial Guinea, Inc., Kosmos International Petroleum, Inc., ABSA Bank Limited, Credit Agricole Corporate and Investment Bank, ING Belgium SA/NV, Natixis, N.B.S.A Limited, Societe Generale, London Branch, The Standard Bank of South Africa Limited, Isle of Man Branch, Standard Chartered Bank, and SMBC Bank International PLC (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2023, and incorporated herin by reference).
	Agreements with Shareholders and Directors
10.41	Form of Director Indemnification Agreement (filed as Exhibit 10.27 to the Company's Registration Statement on Form S-1/A filed April 14, 2011 (File No. 333-171700), and incorporated herein by reference).
10.42	Shareholders Agreement, dated as of May 10, 2011, among Kosmos Energy Ltd. and the other parties signatory thereto (filed as Exhibit 9.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2012, and incorporated herein by reference) (the "Shareholders Agreement").
10.43	Amended and Restated Registration Rights Agreement, dated as of October 7, 2009, among Kosmos Energy Holdings and the other parties signatory thereto (filed as Exhibit 10.32 to the Company's Annual Report on Form 10-K for the year ended December 31, 2012, and incorporated herein by reference).
10.44	Joinder Agreement to the Registration Rights Agreement, dated as of May 10, 2011, among Kosmos Energy Ltd. and the other parties signatory thereto (filed as Exhibit 10.33 to the Company's Annual Report on Form 10-K for the year ended December 31, 2012, and incorporated herein by reference).
10.45	Amendment No. 1 to the Registration Rights Agreement, dated as of February 8, 2013, among Kosmos Energy Ltd. and the other parties signatory thereto (filed as Exhibit 10.34 to the Company's Annual Report on Form 10-K for the year ended December 31, 2012, and incorporated herein by reference).
	Management Contracts/Compensatory Plans or Arrangements
10.46†	Long Term Incentive Plan (filed as Exhibit 99.1 to the Company's Registration Statement on Form S-8 filed May 16, 2011 (File No. 333-174234), and incorporated herein by reference).
10.47†	Long Term Incentive Plan (amended and restated as of January 23, 2015) (filed as Exhibit 99 to the Company's Registration Statement on Form S-8 filed October 2, 2015 (File No. 333-207259), and incorporated herein by reference).
10.48†	Long Term Incentive Plan (amended and restated as of January 23, 2017) (filed as Exhibit 10.64 to the Company's Annual Report on Form 10-K for the year ended December 31, 2016, and incorporated herein by reference).
10.49†	Long Term Incentive Plan (amended and restated as of March 27, 2018) (filed as Exhibit 99 to the Company's Registration Statement on Form S-8 filed November 15, 2018 (File No. 333-207259), and incorporated herein by reference).

Exhibit Number	Description of Document
10.50†	Long Term Incentive Plan (amended and restated as of April 20, 2021) (filed as Exhibit 99 to the Company's Registration Statement on Form S-8 filed June 9, 2021 (File No. 333-256933), and incorporated herein by reference).
10.51†	Long Term Incentive Plan (amended and restated as of April 25, 2023) (filed as Exhibit 99 to the Company's Registration Statement on Form S-8 filed June 9, 2023 (File No. 333-272562), and incorporated herein by reference).
10.52†	Annual Incentive Plan (filed as Exhibit 10.22 to the Company's Registration Statement on Form S-1/A filed March 30, 2011 (File No. 333-171700), and incorporated herein by reference).
10.53†	Form of Restricted Stock Award Agreement (Service-Vesting) (filed as Exhibit 10.50 to the Company's Annual Report on Form 10-K for the year ended December 31, 2014, and incorporated herein by reference).
10.54†	Form of Restricted Stock Award Agreement (Performance-Vesting) (filed as Exhibit 10.51 to the Company's Annual Report on Form 10-K for the year ended December 31, 2014, and incorporated herein by reference).
10.55†	Form of RSU Award Agreement (Service-Vesting) (filed as Exhibit 10.52 to the Company's Annual Report on Form 10-K for the year ended December 31, 2014, and incorporated herein by reference).
10.56†	Form of RSU Award Agreement (Performance-Vesting) (filed as Exhibit 10.13 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2015, and incorporated herein by reference).
10.57†	Form of Directors RSU Award Agreement (Service-Vesting) (filed as Exhibit 10.54 to the Company's Annual Report on Form 10-K for the year ended December 31, 2014, and incorporated herein by reference).
10.58†	Form of Directors Award Agreement (Elective Shares) (filed as Exhibit 10.73 to the Company's Annual Report on Form 10-K for the year ended December 31, 2021, and incorporated herein by reference).
10.59†	Offer Letter, dated September 1, 2011, between Kosmos Energy, LLC and Jason Doughty (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2014, and incorporated herein by reference).
10.60†	Offer Letter, dated May 22, 2013, between Kosmos Energy, LLC and Christopher Ball (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2014, and incorporated herein by reference).
10.61†	Offer Letter, dated January 10, 2014, between Kosmos Energy, LLC and Andrew Inglis (filed as Exhibit 10.58 to the Company's Annual Report on Form 10-K for the year ended December 31, 2013, and incorporated herein by reference).
10.62†	Offer Letter between Kosmos Energy Gulf of Mexico, LLC and Richard R. Clark dated August 3, 2018 (filed as Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2019, and incorporated herein by reference).
10.63†	Kosmos Energy Ltd. Change in Control Severance Policy for U.S. Employees (amended and restated as of January 19, 2022) (filed as Exhibit 10.81 to the Company's Annual Report on Form 10-K for the year ended December 31, 2021, and incorporated herein by reference).
10.64†	Offer Letter, dated November 12, 2019, between Kosmos Energy, LLC and Ronald Glass (filed as Exhibit 10.73 to the Company's Annual Report on Form 10-K for the year ended December 31, 2019, and incorporated herein by reference).
10.65†	Offer Letter, dated November 12, 2019, between Kosmos Energy, LLC and Neal D. Shah (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2020, and incorporated herein by reference).
10.66†	Kosmos Energy Deferred Compensation Plan (effective February 1, 2017) (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017, and incorporated herein by reference).
	Deep Gulf Energy Acquisition
10.67	Securities Purchase Agreement by and among DGE Group Series Holdco, LLC, and each of its three designated series, DGE Group Series Holdco, LLC, Series I, DGE Group Series Holdco, LLC, Series, II, DGE Group Series Holdco, LLC, Series III, and Kosmos Energy Gulf of Mexico, LLC dated August 3, 2018 (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed November 5, 2018 (File No. 001-35167), and incorporated herein by reference).
	Anadarko WCTP Acquisition
10.68	Share Purchase Agreement dated October 13, 2021 between Kosmos Energy Ghana Holdings Limited and Anadarko Offshore Holding Company, LLC (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K filed October 13, 2021 (File No. 001-35167), and incorporated herein by reference).
	Other Exhibits

Exhibit Number	Description of Document
10.69††	Asset Sale Agreement related to Blocks 3013 and 3113 (North Cape Ultra Deep) offshore South Africa, dated September 8, 2020, between Shell Offshore Upstream South Africa B.V. and Kosmos Energy South Africa Limited (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2020, and incorporated herein by reference).
10.70††	Share Sale and Purchase Agreement related to the sale and purchase of shares of KE Namibia Company, KE STP Company, and KE Suriname Company, dated September 8, 2020, between Kosmos Energy Operating, Kosmos Energy Holdings and B.V. Dordtsche Petroleum Maatschappij (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2020, and incorporated herein by reference).
10.71††	Portfolio Agreement, dated September 8, 2020, between Kosmos Energy Operating and B.V. Dordtsche Petroleum Maatschappij (filed as Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2020, and incorporated herein by reference).
10.72	Parent Guarantee Agreement, dated September 30, 2020, between Kosmos Energy Ltd. and CLMG CORP. related to the Senior Secured Term Loan Credit Agreement, dated September 30, 2020, among Kosmos Energy Ltd., Kosmos Energy GoM Holdings, LLC, Kosmos Energy Gulf of Mexico Operations, LLC and CLMG CORP (filed as Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2020, and incorporated herein by reference).
14.1	Code of Business Conduct and Ethics (filed as Exhibit 14.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2011, and incorporated herein by reference).
21.1*	List of Subsidiaries.
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of Ryder Scott Company, L.P.
31.1*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
97.1†*	Kosmos Energy Ltd. Financial Restatement Compensation Recoupment Policy (effective October 2, 2023).
99.1*	Report of Ryder Scott Company, L.P.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.

* Filed herewith.

** Furnished herewith.

† Management contract or compensatory plan or arrangement.

† † Certain confidential portions of this Exhibit have been omitted pursuant to Item 601(b) of Regulation S-K because the identified confidential portions (i) are not material and (ii) would be competitively harmful if publicly disclosed.

FOURTH AMENDMENT TO THE PRODUCTION SHARING CONTRACT FOR BLOCK G, OFFSHORE REPUBLIC OF EQUATORIAL GUINEA

This Fourth Amendment to the Production Sharing Contract for Block G, offshore Republic of Equatorial Guinea (this "Amendment") is entered into in Malabo, Republic of Equatorial Guinea on the 1st day of February, 2019 (the "Fourth Amendment Date"), between Kosmos-Trident Equatorial Guinea, Inc., a Cayman Islands company ("KTEGI"), Kosmos Equatorial Guinea, Inc., a Cayman Islands company ("KEGI"), Tullow Equatorial Guinea Limited, an Isle of Man company ("Tullow"), and the Republic of Equatorial Guinea (the "STATE") as represented by the Ministry of Mines and Hydrocarbons (the "MINISTRY"). KTEGI, KEGI and Tullow are hereinafter collectively referred to as the ("CONTRACTOR") and the CONTRACTOR and the STATE are sometimes, depending on the context, hereinafter individually referred to as a "Party" and collectively as the "Parties."

WHEREAS, the STATE represented by the Ministry of Mines and Hydrocarbons, KTEGI and Tullow are parties to the Production Sharing Contract for Block "G", offshore Republic of Equatorial Guinea, signed on 26 March 1997, with an effective date of 14 April 1997, as amended on 1 January 2000, 15 December 2005 and 22 October 2017 (the "Contract");

WHEREAS, pursuant to Article 6.l(e) of the Contract and with prior notification to the Ministry of Mines and Hydrocarbons, the following assignment has been made to take effect as of 1 January 2019 (the "Effective Date"): the assignment by KTEGI of a forty decimal three seven five percent (40.375%) equity participating interest, which is burdened by a forty two decimal five percent (42.50%) paying interest, in the rights and obligations in the Contract to KEGI, its Affiliated Company(the "Assignment") The remaining interest will be retained by KTEGI, which shall be renamed Trident Equatorial Guinea, Inc. ("TEGI") after the Effective Date;

WHEREAS, following the Assignment:

(A) Kosmos-Trident International Petroleum, Inc. ("KTIPI”) (KEGI's and TEGI's parent company) will transfer its interest in KEGI to Kosmos Energy Equatorial Guinea ("Kosmos EG") via its parent company; and

(B) Kosmos EG will return its ownership (50% of the issued shares) in KTIPI back to KTIPI, following which KTEGI will be a wholly owned subsidiary of Trident Energy EG Operations, Ltd. (together the "Reorganisation"),

(together the Assignment and the Reorganisation being the "Unwind"); and

WHEREAS, the Parties agreed to modify the Contract to reflect the Assignment as well as other various related matters.

NOW THEREFORE, in consideration of the terms and conditions set forth herein, the Parties hereby agree as follows:

<u>Article</u> <u>1</u> Scope

Except as modified herein, the terms of the Contract shall remain valid and in full force and effect.

<u>Article</u> <u>2</u> Participating Interests

The equity percentage interest and paying interest held by the Parties as of the Effective Date are as follows:

PARTY	EQUITY PARTICIPATING INTEREST	PAYING INTEREST
STATE	Five percent (5%)	Zero percent (0%)
KTEGI (TEGI)	Forty decimal three seven five percent (40.375%)	Forty-two decimal five percent (42.5%)
KEGI	Forty decimal three seven five percent (40.375%)	Forty-two decimal five percent (42.5%)
TULLOW	Fourteen decimal two five percent (14.25%)	Fifteen percent (15%)

The Parties agree that KTEGI shall remain as Operator under the Contract.

As from the Effective Date all references in the Contract to KTEGI shall be amended to TEGI, and all references to Kosmos-Trident Equatorial Guinea, Inc. shall be amended to TEGI.

<u>Article</u> <u>3</u> Notices

As from the Effective Date, the Notice provisions of the Contract in Article 15.1 are amended to add KEGI as a Party, KEGI's contact details being hereby added as follows:

Kosmos Equatorial Guinea, Inc.
c/o Walkers Corporate Limited Cayman Corporate Centre
27 Hospital Road
George Town, Grand Cayman KYI-9008 Cayman Islands
Attn: General Counsel

<u>Article</u> <u>4</u> Tax

4.1 The Parties agree that the Unwind is not subject to any form of taxation, levies or fees which would be required to be paid by CONTRACTOR and that no taxable gain or taxable loss arises from the Unwind.

4.2 KEGI and TEGI will each have 50% of KTEGI's pre-Unwind tax basis of the assets and Contract rights and obligations transferred.

4.3 The Unwind will not result in any loss of rights or change in position for the CONTRACTOR under any agreement with the Republic of Equatorial Guinea, including under the Settlement Agreement between the Republic of Equatorial Guinea, Kosmos Trident Equatorial Guinea, Inc. and Tullow Equatorial Guinea Limited dated 22 October 2017.

KTEGI shall be fully responsible for all fiscal obligations and any other such obligations which occurred prior to the Unwind Effective Date. After the Effective Date TEGI and KEGI will each be audited separately, each shall receive its own separate notifications, separate subsequent audit reports and each shall file its own separate audit responses.

<u>Article</u> <u>5</u>
Transfer to Affiliated Company

5.1 The Parties agree that the Unwind constitutes transfers between Affiliated Companies (as defined in the Contract) pursuant to Article 6.1(e) of the Contract.

5.2 Furthermore, the Parties agree that the Unwind is not subject to the provisions of Articles 102-105 of the Hydrocarbons Law No.8/2006 of 3 November of the Republic of Equatorial Guinea.

<u>Article</u> <u>6</u> Miscellaneous

6.1 Each of the Parties shall carry out all acts and measures as shall be necessary to fully perform and carry out this Amendment.

6.2 This Amendment constitutes the entire agreement among the Parties and may not be amended or modified except by a written document signed by the Parties. In the event of any conflict between the provisions of this Amendment and the Contract with respect to the subject matter hereof, the provisions of this Amendment shall prevail.

6.3 This Amendment shall inure to the benefit of and be binding upon the successors and assignees of the Parties.

6.4 This Amendment shall become effective and shall have the force of law with effect as of the Effective Date.

6.5 This Amendment is written and signed in eight (8) copies, four (4) in Spanish and four (4) in English that shall constitute a single signed original. In the event of a conflict over the interpretation or implementation of the contents of this Amendment, the Spanish text shall prevail.

6.6 In the event of a dispute arising out of or related to the interpretation or meaning of this Amendment, the Consultation and Arbitration provisions of Article XIII of the Contract and the applicable law under Article XVI of the Contract shall apply.

IN WITNESS WHEREOF, the Parties hereto execute this Amendment on the day and year indicated below.

FOR THE REPUBLIC OF EQUATORIAL GUINEA:

THE MINISTRY OF MINESAND HYDROCARBONS OF THE REPUBLIC OF EQUATORIAL GUINEA

	/s/ Gabriel M. Obiang Lima
Name:	Gabriel M. Obiang Lima
Title:	Minister of Mines and Hydrocarbons
Date:	February 1, 2019

THE MINISTRY OF FINANCE, ECONOMY AND PLANNING OF THE REPUBLIC OF EQUATORIAL GUINEA

IN RELATION TO ARTICLE 4 HEREIN FOR PURPOSES OF ARTICLE 29 OF THE GENERAL TAX LAW

	/s/ Lucas Abaga Nchama
Name:	Lucas Abaga Nchama
Title:	Minister of Finance, Economy and Planning
Date:	February 1, 2019

FOR THE CONTRACTOR:

KOSMOS-TRIDENT EQUATORIAL GUINEA, INC.

	/s/ Franck Poli
Name:	Franck Poli
Title:	Director
Date:	February 1, 2019

KOSMOS EQUATORIAL GUINEA, INC.

	/s/ Neal Shah
Name:	Neal Shah
Title:	Director
Date:	February 1, 2019

TULLOW EQUATORIAL GUINEA LIMITED

	/s/ Adam Holland
Name:	Adam Holland
Title:	Director
Date:	February 1, 2019

Exhibit 10.21

FIFTH AMENDMENT TO THE PRODUCTION SHARING CONTRACT FOR BLOCK G, OFFSHORE REPUBLIC OF EQUATORIAL GUINEA

This Fifth Amendment to the Production Sharing Contract for Block G, offshore Republic of Equatorial Guinea (this "Amendment") is entered into in Malabo, Republic of Equatorial Guinea on the 5th day of May, 2022 (the "Fifth Amendment Date"), between Trident Equatorial Guinea, Inc., a Cayman Islands company ("TEGI"), Kosmos Equatorial Guinea, Inc., a Cayman Islands company ("KEGI"), Panoro Equatorial Guinea Limited ("PEGL"), an Isle of Man company and Guinea Ecuatorial de Petroleos ("GEPetrol") and the Republic of Equatorial Guinea (the "STATE") as represented by the Ministry of Mines and Hydrocarbons (the "MINISTRY").

TEGI, KEGI, PEGL and GEPetrol are hereinafter collectively referred to as the ("CONTRACTOR") and the CONTRACTOR and the STATE are sometimes, depending on the context, hereinafter individually referred to as a "Party" and collectively as the "Parties."

WHEREAS, the STATE represented by the Ministry of Mines and Hydrocarbons, TEGI, KEGI and PEGL are parties to the Production Sharing Contract for Block "G", offshore Republic of Equatorial Guinea, signed on 26 March 1997, with an effective date of 14 April 1997, as amended on 1 January 2000, 15 December 2005, 22 October 2017 and 1 February 2019 (the "Contract").

WHEREAS, pursuant to the Assignment of State Participating Interest, in the PSC for Block G dated January 01, 2000, the Contractor assigned to the STATE 5% Carried Interest.

WHEREAS, pursuant to Decrees 9/2001 dated February 7th 2001; 75/2001 dated August 27th 2001; 84/2002 dated October 15th 2002, the STATE transferred its participating interests in all the PSCs signed prior to the creation of GEPetrol to GEPetrol and this amendment is intended to give effect to said mandate.

WHEREAS, the STATE through the MINISTRY, by means of a letter of assignment dated 12.04.22 transferred its Participation Interest in Block G to GEPetrol.

WHEREAS at the request of the CONTRACTOR on January 28th, 2022, the Parties, agreed to amend the CONTRACT for the purposes of extending the Contract term until December 31st, 2040, both for the CEIBA Field and the OKUME COMPLEX Field, as defined in Annex "A" of the CONTRACT.

NOW THEREFORE it is hereby agreed as follows.

<u>Article 1</u> SCOPE

Except as modified herein the terms of the Contract as amended shall remain valid and in full force and effect.

Article 2 DEFINITIONS

The terms and phrases defined in the Contract and used herein shall have the same meaning as in the Contract unless the context herein otherwise provides.

Article 3
TERM, TERMINATION AND CANCELLATION

A new paragraph shall be added to Article 2.7 namely (article 2.7A) as follows:

"2.7*A Notwithstanding the provisions of Article* 2. 7 *above, this Contract will continue in existence with respect to the Ceiba Field and the Okume Complex Field, as defined in Annex "A" and Annex "B" of the Contract, until the 31st of December 2040".*

Article 4 PARTICIPATING NTERESTS

Article (2) of the Fourth Amendment to the Block G CONTRACT dated February 01, 2019, is amended to reflect that references made to the STATE shall be read as GEPetrol.

PARTY	PARTICIPATING INTEREST	PAYING INTEREST
GEPETROL	5%	0%
TEGI	40.375%	42.5%
KEGI	40.375%	42.5%
PEGL	14.25%	15%

Article 5

SOCIAL PROJECTS

A new Article 6.6 will be added to the Contract as follows:

"Article 6.6 - Social projects: *Contractor shall commit Seven Hundred and Fifty Thousand United States Dollars (US$750,000) each Calendar Year to cooperate with non-governmental organisations in charitable works to develop society, sports activities and health programs to fight and prevent disease, as well as other non-profit related activities. The sums paid by CONTRACTOR* *pursuant to this Article 6.6 will be tax deductible and cost recoverable as Petroleum Operations Expenditures in accordance with the provisions of the Contract."*

Article 6 MISCELLANEOUS

6.1 Each of the Parties shall carry out all acts and measures as shall be necessary to fully perform and carry out this Amendment.

6.2 This Amendment may not be amended or modified except by a written document signed by the Parties. In the event of any conflict between the provisions of this Amendment and the Contract (as previously amended) with respect to the subject matter hereof, the provisions of this Amendment shall prevail.

6.3 This Amendment shall inure to the benefit of and be binding upon the successors and assignees of the Parties.

6.4 This Amendment shall become effective and shall have the force of law on and from the Effective Date.

6.5 This Amendment is written and signed in eight (8) copies, four (4) in Spanish and four (4) in English that shall constitute a single signed original. In the event of a conflict over the interpretation or implementation of the contents of this Amendment, the Spanish text shall prevail.

6.6 In the event of a dispute arising out of or related to the interpretation or meaning of this Amendment, the Consultation and Arbitration provisions of Article XIII of the Contract and the applicable law under Article XVI of the Contract shall apply.

IN WITNESS WHEREOF, the Parties hereto execute this Amendment on the day and year indicated below.

FOR THE REPUBLIC OF EQUATORIAL GUINEA:

THE MINISTRY OF MINES AND HYDROCARBONS OF THE REPUBLIC OF EQUATORIAL GUINEA

	/s/ Gabriel M. Obiang Lima
Name:	Gabriel M. Obiang Lima
Title:	Minister of Mines and Hydrocarbons
Date:	May 6, 2022

FOR THE CONTRACTOR:

TRIDENT EQUATORIAL GUINEA, INC.

	/s/ Arthur de Fautereau
Name:	Arthur de Fautereau
Title:	General Manager
Date:	May 4, 2022

KOSMOS EQUATORIAL GUINEA, INC.

	/s/ Fidel Envo
Name:	Fidel Envo
Title:	VP – Country Manager
Date:	May 4, 2022

PANORO EQUATORIAL GUINEA LIMITED

	/s/ Antonino Edjang Ondo
Name:	Antonino Edjang Ondo
Title:	Country Manager - EG
Date:	May 4, 2022

GUINEA EQUATORIAL DE PETROLEOS

	/s/ Antonio Oburu Ondo
Name:	Antonio Oburu Ondo
Title:	General Manager
Date:	May 4, 2022

List of Subsidiaries

Subsidiary	Jurisdiction of Incorporation
Kosmos Energy Ltd.	Delaware
Kosmos Energy Delaware Holdings, LLC	Delaware
Kosmos Energy Holdings	Cayman Islands
Kosmos Energy LLC	Texas
Kosmos Energy Operating	Cayman Islands
Kosmos Energy Ventures	Cayman Islands
Kosmos Energy Finance International	Cayman Islands
Kosmos Energy International	Cayman Islands
Kosmos Energy Development	Cayman Islands
Kosmos Energy Ghana HC	Cayman Islands
Kosmos Energy Suriname	Cayman Islands
Kosmos Energy Mauritania	Cayman Islands
Kosmos Energy Equatorial Guinea	Cayman Islands
Kosmos Energy Senegal	Cayman Islands
Kosmos Energy Global Supply	Cayman Islands
Kosmos Energy Sao Tome and Principe	Cayman Islands
Kosmos Energy Sao Tome and Principe Block 4	Cayman Islands
Kosmos Energy GOM Holdings, LLC	Delaware
Kosmos Energy Gulf of Mexico, LLC	Delaware
Kosmos Energy Gulf of Mexico Management, LLC	Delaware
Kosmos Energy Gulf of Mexico Operations, LLC	Delaware
Houston Energy Deepwater Ventures V, LLC	Texas
Kosmos Energy Investments Senegal Limited	United Kingdom
Kosmos International Petroleum, Inc.	Cayman Islands
Kosmos Equatorial Guinea, Inc.	Cayman Islands
Kosmos Energy Tortue Finance	Cayman Islands
Kosmos Energy Ghana Holdings Limited	United Kingdom
Kosmos Energy Ghana Investments	Cayman Islands
Kosmos Energy LNG Marketing Ltd.	United Kingdom

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statements (Form S-8, No. 333-272562, Form S-8, No. 333-256933, Form S-8, No. 333-228397, Form S-8, No. 333-207259, and Form S-8, No. 333-174234) pertaining to the Kosmos Energy Ltd. Long Term Incentive Plan and the Registration Statements (Form S-3, No. 333-257246, Form S-3, No. 333-230284 and Form S-3, No. 333-227084) of Kosmos Energy Ltd. and in the related Prospectus of our reports dated February 26, 2024, with respect to the consolidated financial statements and schedules of Kosmos Energy Ltd. and the effectiveness of internal control over financial reporting of Kosmos Energy Ltd., included in this Annual Report (Form 10-K) of Kosmos Energy Ltd. for the year ended December 31, 2023.

/s/ Ernst & Young LLP

Dallas, Texas
February 26, 2024

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

EXHIBIT 23.2

February 26, 2024

Mr. Tim Nicholson
Kosmos Energy, LLC
8176 Park Lane, Suite 500
Dallas, Texas 75231

We hereby consent to (1) the reference of our firm and to the use of our reports of the Greater Jubilee, TEN, Ceiba, Okume, U.S. Gulf of Mexico, and Greater Tortue Project Areas effective December 31, 2023 and dated January 15, 2024, in the Kosmos Energy Ltd. Annual Report on Form 10-K for the year ended December 31, 2023, to be filed with the U.S. Securities Exchange Commission on or about February 26, 2024; and (2) the incorporation by reference of our reports of the Greater Jubilee, TEN, Ceiba, Okume, U.S. Gulf of Mexico, and Greater Tortue Project Areas effective December 31, 2023 and dated January 15, 2024 in the Kosmos Energy Ltd. Registration Statements pertaining to the Kosmos Energy Ltd. Long Term Incentive Plan (Form S-8, No. 333-174234, Form S-8, No. 333-207259, Form S-8, No. 333-228397, Form S-8, No. 333-256933, and Form S-8, No. 333-272562) and the Kosmos Energy Ltd. Registration Statements (Form S-3, No. 333-227084, Form S-3, No. 333-230284, and Form S-3, No. 333-257246,) and in any related prospectus, including any reference to our firm under the heading “Experts” in such prospectus.

/s/ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

SUITE 2800, 350 7TH AVENUE, S.W. CALGARY, ALBERTA T2P 3N9 TEL (403) 262-2799
633 17TH STREET, SUITE 1700 DENVER, COLORADO 80202 TEL (303) 339-8110

Exhibit 31.1

Certification of Chief Executive Officer

I, Andrew G. Inglis, certify that:

1. I have reviewed this annual report on Form 10-K of Kosmos Energy Ltd.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2024

/s/ ANDREW G. INGLIS

Andrew G. Inglis
Chairman of the Board of Directors and
Chief Executive Officer (Principal Executive Officer)

Exhibit 31.2

Certification of Chief Financial Officer

I, Neal D. Shah, certify that:

1. I have reviewed this annual report on Form 10-K of Kosmos Energy Ltd.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2024

/s/ NEAL D. SHAH

Neal D. Shah
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32.1

Certification of Chief Executive Officer
Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the accompanying annual report of Kosmos Energy Ltd. (the "Company") on Form 10-K for the period ended December 31, 2023, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Andrew G. Inglis, Chairman of the Board of Directors and Chief Executive Officer of the Company, hereby certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 26, 2024

/s/ ANDREW G. INGLIS

Andrew G. Inglis
Chairman of the Board of Directors and Chief Executive Officer
(Principal Executive Officer)

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

Certification of Chief Financial Officer
Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the annual report of Kosmos Energy Ltd. (the “Company”) on Form 10-K for the period ended December 31, 2023, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Neal D. Shah, Senior Vice President and Chief Financial Officer of the Company, hereby certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 26, 2024

/s/ NEAL D. SHAH

Neal D. Shah
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

KOSMOS ENERGY LTD.
FINANCIAL RESTATEMENT COMPENSATION RECOUPMENT POLICY

This Kosmos Energy Ltd. Financial Restatement Compensation Recoupment Policy (this "**Policy**") has been adopted by the Compensation Committee (the "**Committee**") of the Board of Directors (the "**Board**") of Kosmos Energy Ltd. (the "**Company**") on November 16, 2023. This Policy provides for the recoupment of certain executive compensation in the event of an accounting restatement resulting from material noncompliance with financial reporting requirements under U.S. federal securities laws in accordance with the terms and conditions set forth herein. This Policy is intended to comply with the requirements of Section 10D of the Securities Exchange Act of 1934, as amended ("**Exchange Act**") and Section 303A.14 of the NYSE Listed Company Manual (the "**Listing Rule**").

1. <u>Definitions</u>. For the purposes of this Policy, the following terms shall have the meanings set forth below. Capitalized terms used but not defined in this Policy have the meanings set forth in the Kosmos Energy Ltd. Long Term Incentive Plan (as may be amended from time to time, the "**LTIP**").

(a) "**Covered Compensation**" means any Incentive-based Compensation "received" by a Covered Executive during the applicable Recoupment Period; *provided* that:

(i) such Incentive-based Compensation was received by such Covered Executive (A) on or after the Effective Date, (B) after he or she commenced service as an Executive Officer and (C) while the Company had a class of securities publicly listed on a United States national securities exchange; and

(ii) such Covered Executive served as an Executive Officer at any time during the performance period applicable to such Incentive-based Compensation.

For purposes of this Policy, Incentive-based Compensation is "**received**" by a Covered Executive during the fiscal period in which the Financial Reporting Measure applicable to such Incentive-based Compensation (or portion thereof) is attained, even if the payment or grant of such Incentive-based Compensation is made thereafter.

(b) "**Covered Executive**" means any current or former Executive Officer.

(c) "**Effective Date**" means October 2, 2023.

(d) "**Exchange Act**" means the U.S. Securities Exchange Act of 1934, as amended.

(e) "**Executive Officer**" means, with respect to the Company, (i) its president, (ii) its principal financial officer, (iii) its principal accounting officer (or if there is no such accounting officer, its controller), (iv) any vice-president in charge of a principal business unit, division or function (such as sales, administration or finance), (v) any other officer who performs a policy-making function for the Company (including any officer of the Company's parent(s) or subsidiaries if they perform policy-making functions for the Company), and (vi) any other person who performs similar policy-making functions for the Company. Policy-making function is not intended to include policy-making functions that are not significant. The determination as to an individual's status as an Executive Officer shall be made by the Committee and such determination shall be final, conclusive and binding on such individual and all other interested persons.

(f) "**Financial Reporting Measure**" means any (i) measure that is determined and presented in accordance with the accounting principles used in preparing the Company's financial statements, (ii) stock price measure or (iii) total shareholder return measure (and any measures that are derived wholly or in part from any measure referenced in clause (i), (ii) or (iii) above). For the avoidance of doubt, any such measure does not need to be presented within the Company's financial statements or included in a filing with the U.S. Securities and Exchange Commission to constitute a Financial Reporting Measure.

(g) "**Financial Restatement**" means a restatement of the Company's financial statements due to the Company's material noncompliance with any financial reporting requirement under U.S. federal securities laws that is required in order to correct:

(i) an error in previously issued financial statements that is material to the previously issued financial statements; or

(ii) an error that would result in a material misstatement if the error were (A) corrected in the current period or (B) left uncorrected in the current period.

For purposes of this Policy, a Financial Restatement shall not be deemed to occur in the event of a restatement of the Company's financial statements due to an out-of-period adjustment (i.e., when the error is immaterial to the previously issued financial statements and the correction of the error is also immaterial to the current period) or a retrospective (1) application of a change in accounting principles; (2) revision to reportable segment information due to a change in the structure of the Company's internal organization; (3) reclassification due to a discontinued operation; (4) application of a change in reporting entity, such as from a reorganization of entities under common control; or (5) revision for stock splits, reverse stock splits, stock dividends or other changes in capital structure.

(h) "**Incentive-based Compensation"** means any compensation (including, for the avoidance of doubt, any cash or equity or equity-based compensation, whether deferred or current) that is granted, earned and/or vested based wholly or in part upon the achievement of a Financial Reporting Measure. For purposes of this Policy, "Incentive-based Compensation" shall also be deemed to include any amounts which were determined based on (or were otherwise calculated by reference to) Incentive-based Compensation (including, without limitation, any amounts under any long-term disability, life insurance or supplemental retirement or severance plan or agreement or any notional account that is based on Incentive-based Compensation, as well as any earnings accrued thereon).

(i) "**NYSE**" means the New York Stock Exchange, or any successor thereof.

(j) "**Recoupment Period**" means the three fiscal years completed immediately preceding the date of any applicable Recoupment Trigger Date. Notwithstanding the foregoing, the Recoupment Period additionally includes any transition period (that results from a change in the Company's fiscal year) within or immediately following those three completed fiscal years, provided that a transition period between the last day of the Company's previous fiscal year end and the first day of its new fiscal year that comprises a period of nine (9) to twelve (12) months would be deemed a completed fiscal year.

(k) "**Recoupment Trigger Date**" means the earlier of (i) the date that the Board (or a committee thereof or the officer(s) of the Company authorized to take such action if Board action is not required) concludes, or reasonably should have concluded, that the Company is required to prepare a Financial Restatement, and (ii) the date on which a court, regulator or other legally authorized body directs the Company to prepare a Financial Restatement.

2. Recoupment of Erroneously Awarded Compensation.

(a) In the event of a Financial Restatement, if the amount of any Covered Compensation received by a Covered Executive (the "**Awarded Compensation**") exceeds the amount of such Covered Compensation that would have otherwise been received by such Covered Executive if calculated based on the Financial Restatement (the "**Adjusted Compensation**"), the Company shall reasonably promptly recover from such Covered Executive an amount equal to the excess of the Awarded Compensation over the Adjusted Compensation, each calculated on a pre-tax basis (such excess amount, the "**Erroneously Awarded Compensation**").

(b) If (i) the Financial Reporting Measure applicable to the relevant Covered Compensation is stock price or total shareholder return (or any measure derived wholly or in part from either of such measures) and (ii) the amount of Erroneously Awarded Compensation is not subject to mathematical recalculation directly from the information in the Financial Restatement, then the amount of Erroneously Awarded Compensation shall be determined (on a pre-tax basis) based solely on the Company's reasonable estimate of the effect of the Financial Restatement on the Company's stock price or total shareholder return (or the derivative measure thereof) upon which such Covered Compensation was received.

(c) For the avoidance of doubt, the Company's obligation to recover Erroneously Awarded Compensation is not dependent on (i) if or when the restated financial statements are filed or (ii) any fault of any Covered Executive for the accounting errors or other actions leading to a Financial Restatement.

(d) Notwithstanding anything to the contrary in Sections 2(a) through (c) hereof, the Company shall not be required to recover any Erroneously Awarded Compensation if both (x) the conditions set forth in either of the following clauses (i) or (ii) are satisfied and (y) the Committee (or a majority of the independent directors serving on the Board) has determined that recovery of the Erroneously Awarded Compensation would be impracticable:

(i) the direct expense paid to a third party to assist in enforcing the recovery of the Erroneously Awarded Compensation under this Policy would exceed the amount of such Erroneously Awarded Compensation to be recovered; *provided* that, before concluding that it would be impracticable to recover any amount of Erroneously Awarded Compensation pursuant to this Section 2(d), the Company shall have first made a reasonable attempt to recover such Erroneously Awarded Compensation, document such reasonable attempt(s) to make such recovery and provide that documentation to the NYSE; or

(ii) recovery of the Erroneously Awarded Compensation would likely cause an otherwise tax-qualified retirement plan, under which benefits are broadly available to employees of the Company, to fail to meet the requirements of Sections 401(a)(13) or 411(a) of the U.S. Internal Revenue Code of 1986, as amended (the "**Code**").

(e) The Company shall not indemnify any Covered Executive, directly or indirectly, for any losses that such Covered Executive may incur in connection with the recovery of Erroneously Awarded Compensation pursuant to this Policy, including through the payment of insurance premiums or gross-up payments.

(f) The Committee shall determine, in its sole discretion, the manner and timing in which any Erroneously Awarded Compensation shall be recovered from a Covered Executive in accordance with applicable law, including, without limitation, by (i) requiring reimbursement of Covered Compensation previously paid in cash; (ii) seeking recovery of any gain realized on the vesting, exercise, settlement, sale, transfer or other disposition of any equity or equity-based awards; (iii) offsetting the Erroneously Awarded Compensation amount from any compensation otherwise owed by the Company or any of its affiliates to the Covered Executive; (iv) cancelling outstanding vested or unvested equity or equity-based awards; and/or (v) taking any other remedial and recovery action permitted by applicable law. For the avoidance of doubt, except as set forth in Section 2(d), in no event may the Company accept an amount that is less than the amount of Erroneously Awarded Compensation; *provided* that, to the extent necessary to avoid any adverse tax consequences to the Covered Executive pursuant to Section 409A of the Code, any offsets against amounts under any nonqualified deferred compensation plans (as defined under Section 409A of the Code) shall be made in compliance with Section 409A of the Code.

3. Administration. This Policy shall be administered by the Committee. All decisions of the Committee shall be final, conclusive and binding upon the Company and the Covered Executives, their beneficiaries, executors, administrators and any other legal representative. The Committee shall have full power and authority to (i) administer and interpret this Policy; (ii) correct any defect, supply any omission and reconcile any inconsistency in this Policy; and (iii) make any other determination and take any other action that the Committee deems necessary or desirable for the administration of this Policy and to comply with applicable law (including Section 10D of the Exchange Act) and applicable stock market or exchange rules and regulations. Notwithstanding anything to the contrary contained herein, to the extent permitted by Section 10D of the Exchange Act and the Listing Rule, the Board may, in its sole discretion, at any time and from time to time, administer this Policy in the same manner as the Committee.

4. Amendment/Termination. Subject to Section 10D of the Exchange Act and the Listing Rule, this Policy may be amended or terminated by the Committee at any time. To the extent that any applicable law, or stock market or exchange rules or regulations require recovery of Erroneously Awarded Compensation in circumstances in addition to those specified herein, nothing in this Policy shall be deemed to limit or restrict the right or obligation of the Company to recover Erroneously Awarded Compensation to the fullest extent required by such applicable law, stock market or exchange rules and regulations. Unless otherwise required by applicable law, this Policy shall no longer be effective from and after the date that the Company no longer has a class of securities publicly listed on a United States national securities exchange.

5. Interpretation. Notwithstanding anything to the contrary herein, this Policy is intended to comply with the requirements of Section 10D of the Exchange Act and the Listing Rule (and any applicable regulations, administrative interpretations or stock market or exchange rules and regulations adopted in connection therewith). The provisions of this Policy shall be interpreted in a manner that satisfies such requirements and this Policy shall be operated accordingly. If any provision of this Policy would otherwise frustrate or conflict with this intent, the provision shall be interpreted and deemed amended so as to avoid such conflict.

6. Other Compensation Clawback/Recoupment Rights. Any right of recoupment under this Policy is in addition to, and not in lieu of, any other remedies, rights or requirements with respect to the clawback or recoupment of any compensation that may be available to the Company pursuant to the terms of any other recoupment or clawback policy of the Company (or any of its affiliates) that may be in effect from time to time (including, without limitation the Kosmos Energy Ltd. Detrimental Conduct Compensation Recoupment Policy), any provisions in any employment agreement, offer letter, equity plan, equity award agreement or similar plan or agreement, and any other legal remedies available to the Company, as well as applicable law, stock market or exchange rules, listing standards or regulations; *provided*, *however*, that any amounts recouped or clawed back under any other policy that would be recoupable under this Policy shall count toward any required clawback or recoupment under this Policy and vice versa.

7. Exempt Compensation. Notwithstanding anything to the contrary herein, the Company has no obligation under this Policy to seek recoupment of amounts paid to a Covered Executive

which are granted, vested or earned based solely upon the occurrence or non-occurrence of nonfinancial events. Such exempt compensation includes, without limitation, base salary, time-vesting awards, compensation awarded on the basis of the achievement of metrics that are not Financial Reporting Measures or compensation awarded solely at the discretion of the Committee or the Board, *provided* that such amounts are in no way contingent on, and were not in any way granted on the basis of, the achievement of any Financial Reporting Measure performance goal.

8. Miscellaneous.

(a) Any applicable award agreement or other document setting forth the terms and conditions of any compensation covered by this Policy shall be deemed to include the restrictions imposed herein and incorporate this Policy by reference and, in the event of any inconsistency, the terms of this Policy will govern. For the avoidance of doubt, this Policy applies to all compensation that is received on or after the Effective Date, regardless of the date on which the award agreement or other document setting forth the terms and conditions of the Covered Executive's compensation became effective, including, without limitation, compensation received under the LTIP or the Company's Annual Incentive Program (and any successor plan thereto).

(b) This Policy shall be binding and enforceable against all Covered Executives and their beneficiaries, heirs, executors, administrators or other legal representatives.

(c) All issues concerning the construction, validity, enforcement and interpretation of this Policy and all related documents, including, without limitation, any employment agreement, offer letter, equity award agreement or similar agreement, shall be governed by, and construed in accordance with, the laws of the State of Delaware, without giving effect to any choice of law or conflict of law rules or provisions (whether of the State of Delaware or any other jurisdiction) that would cause the application of the laws of any jurisdiction other than the State of Delaware.

(d) The Company and any executive covered by this Policy hereto shall initially attempt to resolve all claims, disputes or controversies arising under, out of or in connection with this Policy by conducting good faith negotiations amongst themselves. To ensure the timely and economical resolution of disputes that arise in connection with this Policy, any and all disputes, claims, or causes of action arising from or relating to the enforcement, performance or interpretation of this Policy shall be resolved to the fullest extent permitted by law by final, binding, non-appealable and confidential arbitration, by a single arbitrator, in Dallas, Texas, conducted by the American Arbitration Association under its Commercial Mediation Rules. All parties, including the applicable executives, their beneficiaries, executors, administrators, or any other legal representative, and the Company, hereby waive (x) the right to resolve any such dispute through a trial by jury or judge or administrative proceeding and (y) any objection to arbitration taking place in Dallas, Texas. The arbitrator shall: (i) have the authority to compel adequate discovery for the resolution of the dispute and to award such relief as would otherwise be permitted by law; and (ii) issue a written arbitration decision, to include the arbitrator's essential findings and conclusions and a statement of the award. The arbitrator shall be authorized to award any or all remedies that any party would be entitled to seek in a court of law. All parties, including covered executives, their beneficiaries, executors, administrators, or any other legal representative, and the Company, hereby waive the right to resolve any such dispute through a trial by jury.

(e) If any provision of this Policy is determined to be unenforceable or invalid under any applicable law, such provision will be applied to the maximum extent permitted by applicable law and shall automatically be deemed amended in a manner consistent with its objectives to the extent necessary to conform to any limitations required under applicable law.

Exhibit 99.1

KOSMOS ENERGY LIMITED

Estimated

Future Reserves and Income

Attributable to Certain Interests

and

Derived Through Certain Production Sharing Contracts

SEC Parameters

As of

December 31, 2023

/s/ Tosin Famurewa	/s/ Amara N. Okafor
Tosin Famurewa, P.E., S.P.E.C.	Amara N. Okafor, P.E.
TBPELS License No. 100569	TBPELS License No. 113166
Executive Vice President / Director	Senior Vice President

[SEAL] **[SEAL]**

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

January 15, 2024

Kosmos Energy Limited
8176 Park Lane, Suite 500
Dallas, Texas 75231

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain interests and derived through certain production sharing contracts of Kosmos Energy Limited (Kosmos) as of December 31, 2023. The subject properties are located in Ghana, offshore West Africa, in the West Cape Three Points (WCTP) and Deep Water Tano (DWT) blocks, hereafter referred to as the "Greater Jubilee and TEN Project Areas," Equatorial Guinea, offshore Central Africa, in the G and F blocks, hereafter referred to as the "Ceiba and Okume Project Areas" Mauritania and Senegal, offshore Northwest Africa, in the C-8 and St. Louis Offshore Profond blocks, hereafter referred to as the "Greater Tortue Project Area" and United States of America, federal waters offshore Louisiana and Texas, hereafter referred to as the "Gulf of Mexico Project Area." The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third-party study, completed on January 11, 2024 and presented herein, was prepared for public disclosure by Kosmos in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott in this report represent 100 percent of Kosmos' total net proved liquid hydrocarbon and gas reserves as of December 31, 2023.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2023, are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. At Kosmos' request, we have included estimated gross (100%) reserves, along with the estimated net reserves and income data. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Gross Reserves[1] Data
Derived Through Certain Interests of
Kosmos Energy Limited
As of December 31, 2023

	Proved			
	Developed			
	Producing	Non-Producing	Undeveloped	Total
Gulf of Mexico Project Area				
Gross Reserves				
Oil/Condensate – Mbbl	56,288	7,376	24,804	88,468
Plant Products – Mbbl	4,702	1,663	1,584	7,949
Sales Gas[2] – MMcf	51,642	17,610	23,668	92,920
LNG – MMcf	0	0	0	0
Fuel Gas – MMcf	0	0	2,046	2,046
Greater Jubilee and TEN Project Areas				
Gross Reserves				
Oil/Condensate – Mbbl	141,094	856	135,541	277,491
Plant Products – Mbbl	0	0	0	0
Sales Gas[3] – MMcf	154,333	5,491	153,041	312,865
LNG – MMcf	0	0	0	0
Fuel Gas – MMcf	65,190	0	0	65,190
Ceiba and Okume Project Areas				
Gross Reserves				
Oil/Condensate – Mbbl	43,248	14,491	13,632	71,371
Plant Products – Mbbl	0	0	0	0
Sales Gas – MMcf	0	0	0	0
LNG – MMcf	0	0	0	0
Fuel Gas – MMcf	36,702	0	0	36,702
Greater Tortue Project Area				
Gross Reserves				
Oil/Condensate – Mbbl	0	0	29,751	29,751
Plant Products – Mbbl	0	0	0	0
Sales Gas – MMcf	0	0	0	0
LNG – MMcf	0	0	2,410,590	2,410,590
Fuel Gas – MMcf	0	0	219,150	219,150

	Proved			
	Developed			
	Producing	Non-Producing	Undeveloped	Total
Total				
Gross Reserves				
Oil/Condensate – Mbbl	240,630	22,723	203,728	467,081
Plant Products – Mbbl	4,702	1,663	1,584	7,949
Sales Gas – MMcf	205,975	23,101	176,709	405,785
LNG – MMcf	0	0	2,410,590	2,410,590
Fuel Gas – MMcf	101,892	0	221,196	323,088

[1]These volumes are 100% gross and do not represent net volumes to Kosmos' interests. Net reserves and income are shown below.
[2]Represents gross gas produced at the wellhead, less shrinkage after the extraction of plant products.
[3]Represents gross gas produced at the wellhead, less consumed fuel gas, injected gas, and gas flared as part of operations.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Derived Through Certain Interests of
Kosmos Energy Limited
As of December 31, 2023

	Proved			
	Developed			
	Producing[1]	Non-Producing	Undeveloped	Total
Gulf of Mexico Project Area				
Net Reserves				
Oil/Condensate – Mbbl	12,841	1,128	5,215	19,184
Plant Products – Mbbl	924	179	380	1,483
Sales Gas – MMcf	9,900	1,890	5,070	16,860
LNG – MMcf	0	0	0	0
Fuel Gas – MMcf	0	0	1,123	1,123
Income Data ($M)				
Future Gross Revenue	$1,031,319	$91,986	$414,266	$1,537,571
Deductions	419,823	29,129	224,598	673,550
Future Net Income (FNI)	$ 611,496	$62,857	$189,668	$ 864,021
Discounted FNI @ 10%	$ 560,536	$47,305	$142,848	$ 750,689
Greater Jubilee and TEN Project Areas				
Net Reserves				
Oil/Condensate – Mbbl	46,138	314	46,871	93,323
Plant Products – Mbbl	0	0	0	0
Sales Gas – MMcf	56,897	2,024	56,420	115,341
LNG – MMcf	0	0	0	0
Fuel Gas – MMcf	19,947	0	0	19,947
Income Data ($M)				
Future Gross Revenue	$4,060,771	$33,451	$4,122,124	$8,216,346
Deductions	1,193,815	6,957	1,564,698	2,765,470
Future Net Income (FNI)	$2,866,956	$26,494	$2,557,426	$5,450,876
Discounted FNI @ 10%	$2,307,453	$15,938	$1,742,396	$4,065,787

	Proved			
	Developed			
	Producing[1]	Non-Producing	Undeveloped	Total
Ceiba and Okume Project Areas				
Net Reserves				
Oil/Condensate – Mbbl	14,472	4,851	4,502	23,825
Plant Products – Mbbl	0	0	0	0
Sales Gas – MMcf	0	0	0	0
LNG – MMcf	0	0	0	0
Fuel Gas – MMcf	15,598	0	0	15,598
Income Data ($M)				
Future Gross Revenue	$1,169,520	$392,034	$363,786	$1,925,340
Deductions	864,761	282,525	282,288	1,429,574
Future Net Income (FNI)	$ 304,759	$109,509	$ 81,498	$ 495,766
Discounted FNI @ 10%	$ 338,901	$129,289	$ 85,301	$ 553,491
Greater Tortue Project Area				
Net Reserves				
Oil/Condensate – Mbbl	0	0	7,106	7,106
Plant Products – Mbbl	0	0	0	0
Sales Gas – MMcf	0	0	0	0
LNG – MMcf	0	0	575,465	575,465
Fuel Gas – MMcf	0	0	52,287	52,287
Income Data ($M)				
Future Gross Revenue	$0	$0	$5,363,159	$5,363,159
Deductions	0	0	3,403,676	3,403,676
Future Net Income (FNI)	$0	$0	$1,959,483	$1,959,483
Discounted FNI @ 10%	$0	$0	$ 782,845	$ 782,845
Total				
Net Reserves				
Oil/Condensate – Mbbl	73,451	6,293	63,694	143,438
Plant Products – Mbbl	924	179	380	1,483
Sales Gas – MMcf	66,797	3,914	61,490	132,201
LNG – MMcf	0	0	575,465	575,465
Fuel Gas – MMcf	35,545	0	53,410	88,955
Income Data ($M)				
Future Gross Revenue	$6,261,610	$517,471	$10,263,335	$17,042,416
Deductions	2,478,399	318,611	5,475,260	8,272,270
Future Net Income (FNI)	$3,783,211	$198,860	$ 4,788,075	$ 8,770,146
Discounted FNI @ 10%	$3,206,890	$192,532	$ 2,753,390	$ 6,152,812

[1]*Proved depleted summary consisting of certain P&A liability costs are included with the proved developed producing summary for the Gulf of Mexico Project Area*

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). Fuel gas volumes are attributed to those volumes of gas that are consumed for fuel in field operations, while sales gas volumes are reported on an “as sold basis.” Kosmos elected not to report fuel gas for the Gulf of Mexico Project Area with the exception of the Odd Job field where fuel gas for running subsea pumps is now a cost to the Odd Job partners. At Kosmos’ request, this cost has been subtracted from the Future Gross Revenue of the sales gas in this report. All gas volumes are expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package PHDWin Petroleum Economic Evaluation Software, a copyrighted program of TRC Consultants L.C. and economic models developed in Microsoft EXCEL. These programs were used at the request of Kosmos. Ryder Scott has found these programs to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The deductions incorporate the normal direct costs of operating the wells, recompletion costs, development costs, and certain abandonment costs net of salvage. “Other deductions”, in the Greater Tortue Project Area, consist of joint operating agreement (JOA) overhead cost and training cost. In the Greater Jubilee and TEN Project Areas, abandonment costs (included in the “Development Costs” column of the cash flow projections) are triggered and escrowed several years before the economic limit is reached, and this may result in negative FNI values for certain years prior to abandonment.

Certain gas, oil and condensate processing and handling fees, including compression fees where applicable are included as “Other” and “Ad Valorem Taxes” deductions in the cash flows. The latter are not true ad valorem taxes but represent Kosmos’ throughput fee to Talos for processing and handling of the production volumes from the Tornado field in the Gulf of Mexico Project Area. The separate tracking of this throughput fee in the “Ad Valorem Taxes” column of the cash flows was done at Kosmos’ request.

There are no production taxes associated with any of the Project Areas. The future net income is before the deductions of U.S. state and federal or foreign income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist, nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for approximately 69 percent and gas reserves account for the remaining 31 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded annually. Future net income was discounted at four other discount rates which were also compounded annually. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2023
Discount Rate Percent	Total Proved
5	$7,221,832
15	$5,365,662
20	$4,760,019
25	$4,279,282

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved developed non-producing reserves included herein consist of the shut-in and behind pipe status categories.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves, and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Kosmos' request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

The proved reserves reported herein are limited to the period prior to expiration of current contracts providing the legal rights to produce, or a revenue interest in such production unless evidence indicates that contract renewal is reasonably certain. Furthermore, the subject properties located in Ghana and Equatorial Guinea may be subjected to substantially varying contractual fiscal terms that affect the net revenue to Kosmos for the production of these volumes. The prices and economic return received for these net volumes can vary materially based on the terms of these contracts. Therefore, when applicable, Ryder Scott reviewed the fiscal terms of such contracts and discussed with Kosmos the net economic benefit attributed to such operations for the determination of the net hydrocarbon volumes and income thereof. Ryder Scott has not conducted an exhaustive audit or verification of such contractual information. Neither our review of such contractual information nor our acceptance of Kosmos representations regarding such contractual information should be construed as a legal opinion on this matter.

Ryder Scott did not evaluate the country and geopolitical risks in the countries where Kosmos operates or has interests. Kosmos operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which Kosmos owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves for the properties included herein were estimated by performance methods, the volumetric method, analogy, or a combination of methods. In certain cases, the reserves attributable to producing wells and/or reservoirs were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis, material balance and/or reservoir simulation which utilized extrapolations of historical production and pressure data available through December 2023 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Kosmos and were considered sufficient for the purpose thereof. In other cases, producing reserves were estimated by the volumetric method, analogy, or a combination of methods. These methods were used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserves estimates was considered to be inappropriate. However, available performance data were used to ensure the volumetric parameters in our estimates derived from the volumetric method were appropriate.

The reserves for the properties included herein attributable to the non-producing and the undeveloped status categories were estimated by the volumetric method, analogy, or a combination of methods. The volumetric analysis utilized pertinent well and seismic data furnished to Ryder Scott by Kosmos or obtained from public data sources that were available through November 2023. The data utilized from the analogues in conjunction with well and seismic data incorporated into our volumetric analysis were considered sufficient for the purpose thereof.

To estimate economically producible proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Kosmos has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by Kosmos with respect to property interests owned, contractual terms that govern future net income, production and well tests from examined wells, normal direct costs of operating the wells or leases and all the required facilities such as the FPSO, other costs such as transportation and/or processing fees, recompletion and development costs, development plans, certain abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Kosmos. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If a decline trend has been established, this trend was used as the basis for estimating future production rates. If no production decline trend has been established, one of the following occurred:

- future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves.

- future production rates were projected based on a type well derived from analogy to surrounding historical well production.

- future production rates were based on a combination of historical performance data, volumetric analysis and a numerical simulation model. Future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated “simulation based decline rate” was then applied until depletion of the reserves.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Kosmos. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract.

These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic areas included in the report. Kosmos furnished us with the Heavy Louisiana Sweet price used for the Gulf of Mexico project area. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, NGL processing fees, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by Kosmos. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Kosmos to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Price	Average Realized Price
Africa				
Ghana (Greater Jubilee and TEN Project Areas)				
	Oil	Brent	$82.84/Bbl	$83.67/Bbl
	Gas	Contract	$3.54/Mcf	$3.54/Mcf
Senegal / Mauritania (Greater Tortue Project Area)				
	Condensate	Brent	$82.84/Bbl	$82.84/Bbl
	LNG	(6)	$6.60/MMbtu	$8.30/Mcf
Equatorial Guinea (Ceiba and Okume Project Areas)				
	Oil	Brent	$82.84/Bbl	$80.81/Bbl
North America				
United States (Gulf of Mexico Project Area)				
	Oil	Heavy Louisiana Sweet	$80.06/Bbl	$76.30/Bbl
	NGLs	Heavy Louisiana Sweet	$80.06/Bbl	$20.96/Bbl
	Gas	Henry Hub	$2.64/MMbtu	$2.53/Mcf

[6]The future LNG prices, as specified by Kosmos, are based on the Sales Purchase Agreement (SPA), which is indexed to Brent crude, with a specified heating value of 1.065 MMbtu/scf.

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the contract areas and wells in this report were furnished by Kosmos and are based on their operating expense reports and include only those costs directly applicable to the contract areas or wells. The operating costs include a portion of general and administrative costs allocated directly to the contract areas and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. Certain gas, oil and condensate processing and handling fees, including compression fees where applicable are included as “Other” and “Ad Valorem Taxes” deductions in the cash flows. The latter are not true ad valorem taxes but represent Kosmos’ throughput fee to Talos for processing and handling of the production volumes from the Tornado field. The separate tracking of this throughput fee in the “Ad Valorem Taxes” column of the cash flows was done at Kosmos’ request. For some Gulf of Mexico Project Area assets, we calculated their operating costs using Lease Operating Statements (LOE) provided by Kosmos. For the remaining assets, the operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by Kosmos. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the contract areas or wells.

Development costs were furnished to us by Kosmos and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs.

The estimated net cost of abandonment was included for properties where certain abandonment costs were provided by Kosmos. These abandonment costs were accepted without independent verification, and we have made no inspections to determine if any additional abandonment, decommissioning, and /or restoration costs may be necessary in addition to the costs provided by Kosmos and included herein. Kosmos advises that their contractual share of Mississippi Canyon 697/698/741/742 (Big Bend) field, in the Gulf of Mexico Project Area, Plug and Abandonment (P&A) liability is zero.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with Kosmos' plans to develop these reserves as of December 31, 2023. The implementation of Kosmos' development plans as presented to us and incorporated herein is subject to the approval process adopted by Kosmos' management. As the result of our inquiries during the course of preparing this report, Kosmos has informed us that the development activities included herein have been subjected to and received the internal approvals required by Kosmos management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Kosmos. Kosmos has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, Kosmos has informed us that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans. While these plans could change or evolve from those under existing economic conditions as of December 31, 2023, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

According to Item 1203 (d) of the SEC Regulations, an explanation should be included for the reasons "…why material amounts of proved undeveloped reserves … remain undeveloped for five years or more after disclosure as proved undeveloped reserves." A material amount of proved undeveloped reserves in the Greater Tortue Project Area of this report are forecast to be converted to developed status beyond the five-year time frame. A five-year time frame for converting undeveloped to developed reserves was adopted by the SEC, "unless specific circumstances justify a longer time frame." The Greater Tortue Project, a multi-billion dollar investment, is a partnership between BP Mauritania Investments Limited (BPMIL), BP Senegal Investments Limited (BPSIL), Kosmos Energy Mauritania (KEM), Kosmos Energy Investments Senegal Limited (KEISL), La Societe Mauritanienne Des Hydrocarbures et de Patrimione Miner (SMHPM), and La Societe Des Petroles du Senegal (PETROSEN), the last two being the National Oil Companies (NOC) of the governments of the Islamic Republic of Mauritania and the Republic of Senegal, respectively. There are several long lead items including major equipment, pipelines, infrastructure for facilities that include a floating liquefied natural gas (FLNG) vessel, a deep-water floating production storage and offloading (FPSO) facility, and LNG gas processing facilities in a deep offshore environment. The project has partnership commitment and alignment with about $7.044 Billion spent as of November 2023. All 4 major project segments – Subsea, FPSO, Hub Terminal and FLNG, are proceeding on schedule. It is Ryder Scott's opinion that these special circumstances allow for the recognition of proved reserves for locations that will be developed beyond the five-year time frame.

Current costs used by Kosmos were held constant throughout the life of the properties. However, in some contract areas, anticipated changes to operations during the field life-ramp-down, specifically consolidation of activities, reduced well count and/or fluid handling, and other synergies, are projected to result in certain cost reductions.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to Kosmos Energy Limited. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Kosmos.

Kosmos makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Kosmos has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Forms S-3 and S-8 of Kosmos Energy Limited of the references to our name as well as to the references to our third party report for Kosmos Energy Limited, which appears in the December 31, 2023 annual report on Form 10-K of Kosmos Energy Limited. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Kosmos Energy Limited.

We have provided Kosmos with a digital copy of the original signed document retained in our files. In the event there are any differences between the digital copy included in filings made by Kosmos and the original signed document, the original signed document shall control and supersede the digital copy.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

/s/ Tosin Famurewa

Tosin Famurewa, P.E., S.P.E.C.
TBPELS License No. 100569
Executive Vice President / Director **[SEAL]**

/s/ Amara N. Okafor

Amara N. Okafor, P.E.
TBPELS License No. 113166
Senior Vice President **[SEAL]**

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Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. (Ryder Scott). Tosin Famurewa was the primary technical person responsible for overseeing the estimate of the reserves, future production and income prepared by Ryder Scott presented herein.

Mr. Famurewa, an employee of Ryder Scott since 2006, currently serves as the Executive Vice President and a member of the Board of Directors. He is responsible for executive management and supervising staff and client relations of the company. Before joining Ryder Scott, Mr. Famurewa served in a number of engineering and management positions with Chevron and Texaco. For more information regarding Mr. Famurewa's geographic and job specific experience, please refer to Ryder Scott's website at www.ryderscott.com/Employees.

Mr. Famurewa earned double Bachelor of Science degrees in Chemical Engineering and Material Science and Engineering from University of California at Berkeley in 2000 and a Master of Science degree in Petroleum Engineering from University of Southern California in 2007. He is a licensed Professional Engineer (P.E.) in the State of Texas and a SPE Certified Petroleum Engineer (S.P.E.C.). He is also a licensed professional with the Financial Reporting Council of Nigeria (FRCN). Mr. Famurewa is also a member of the Society of Petroleum Engineers (SPE) and the Society of Petroleum Evaluation Engineers (SPEE). He also maintains active memberships with the World Affairs Council and the Committee on Foreign Relations.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Famurewa fulfills. Mr. Famurewa is a regular speaker on reserve related topics at the annual Sub-Saharan Africa Oil and Gas Conference in Houston, Texas USA.

Based on his educational background, professional training and more than 22 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Famurewa has attained the professional qualifications as a Reserves Estimator and Reserves Auditor as set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the “Modernization of Oil and Gas Reporting; Final Rule” in the Federal Register of National Archives and Records Administration (NARA). The “Modernization of Oil and Gas Reporting; Final Rule” includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The “Modernization of Oil and Gas Reporting; Final Rule”, including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the “SEC regulations”. The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

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

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

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

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

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

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

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

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

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

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

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

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

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.