2025 ANNUAL REPORT

AT KOSMOS ENERGY, OUR PURPOSE IS CLEAR.

We are a leading deepwater exploration and production company focused on meeting the world's growing demand for energy.

We have diversified oil and gas production from key assets offshore Ghana, Mauritania, Senegal and the Gulf of America. In the proven basins where we operate, we are advancing high-quality development opportunities that have come from our exploration success.

As we deliver the energy the world needs today and tomorrow, we strive to be a force for good in our host countries, accelerating economic and social progress.

Fellow Shareholders,

Over the past year, we have focused on improving the business and its ability to perform through the cycle. As we move through 2026, that work is starting to show in higher production, a lower cost base, and a clearer path to increased financial resilience.

Energy markets remain volatile, and at the time of writing oil prices are higher than they have been in recent years. How long this will last, and how much prices may move, remains uncertain. That is why our agenda is focused on operational delivery to supply the energy the world needs – together with measured investment, strict cost discipline, and reducing debt.

Our priorities for 2026 are clear and practical: grow production by around 15% year on year, reduce operating costs by 20%, and lower net debt by at least 10%. We have aligned our capital allocation, operating plans, and leadership focus behind those goals, and they will remain unchanged through market volatility.

GHANA

Maintaining and growing Jubilee production takes a consistent drilling program, high facility uptime, steady water injection, and advanced subsurface imaging to support well selection – actions we are focused on delivering. The 2026 drilling campaign is well underway and building momentum, with further production increases expected as additional wells come online through the year.

For 2026, Jubilee production is forecast at 70,000–80,000 bopd gross. With the Jubilee and TEN licenses now extended to 2040, we are aligned with our partners and the government of Ghana on continued investment to support higher production.

MAURITANIA & SENEGAL

Greater Tortue Ahmeyim (GTA) Phase 1 exited 2025 at the floating LNG vessel's 2.7 million tonnes per annum nameplate production capacity and has performed well early in 2026, with production year-to-date around 2.9 million tonnes per annum. This year, we are targeting 32-36 gross LNG cargoes, up from 18.5 last year. Unit operating costs per mmbtu are expected to decline materially versus 2025 as higher volumes, a lower-cost operating approach, and the FPSO refinancing flow through the cost base.

Looking ahead, GTA Phase 1+ is structured to further reduce unit costs and support domestic gas sales to Mauritania and Senegal as the countries' infrastructure becomes ready to receive the gas. Senegal has begun planning the build-out of its domestic gas pipeline network, an important step toward connecting future volumes to demand centers for power and industrial use.

GULF OF AMERICA

In the Gulf of America, the Tiberius development is progressing, with a planned post-FID farm-down to keep our capital commitment at the right level. We are also preparing the Trailblazer exploration prospect for planned 2027 drilling as part of our strategic alliance with Shell. Both projects are being paced deliberately within a lean capital program and against clear capital-allocation priorities.

FINANCIAL DISCIPLINE

We expect 2026 capital expenditures of approximately $350 million, with the majority directed to the high-return Jubilee drilling program in Ghana. At the same time, we are executing material operating cost reductions during 2026 and continuing to high-grade the portfolio. Together with improved operating performance, these actions are designed to support debt reduction and strengthen the business through the cycle.

RESPONSIBLE OPERATIONS

Operating responsibly remains a core part of our strategy and of how we create long-term value. Our portfolio is anchored by low-cost, lower carbon oil and gas production, which positions us as a reliable and responsible producer as countries balance energy security and affordability with the need to reduce emissions.

External recognition does not define our performance, but it is a useful indicator that our approach is being recognized. In 2025, Kosmos earned MSCI's highest possible AAA rating for the fourth consecutive year, placing us in the top quartile of companies in our sector. We were also named by Newsweek and Statista as one of America's Most Responsible Companies for the sixth consecutive year.

We believe this matters because responsible operations, quality assets, and disciplined execution go together. They support our relationships with host governments and partners, strengthen our license to operate, and position the business to generate value for shareholders over the long term.

OUTLOOK

Our focus for 2026 is delivery: increasing production from our core assets, lowering costs, and reducing debt. We will continue to advance selective, high-value opportunities, but within a capital framework tightly aligned with attractive returns and balance-sheet priorities.

We look forward to sharing more at our annual meeting. On behalf of the entire board of directors, I thank you for your investment, continued trust and support.

ANDREW G. INGLIS
Chairman and
Chief Executive Officer

Financial Highlights

Year Ended (in thousands, except volume data)	2025	2024	2023
Revenues and other income	$ 1,291,650	$ 1,675,562	$ 1,701,535
Net income (loss)	(699,786)	189,851	213,520
Net cash provided by operating activities	134,012	678,249	765,170
Capital expenditures[1]	292,188	828,813	849,999
Total Assets	4,696,626	5,308,988	4,938,134
Net Debt	2,982,530	2,714,997	2,326,239
Average oil sales price per Bbl	66.89	78.70	81.35
Average gas sales price per Mcf	5.28	3.54	2.57
Average NGL sales price per Bbl	29.76	20.55	20.61
Average total sales price per Boe	57.48	71.27	73.80
Sales volumes (million barrels of oil equivalent)	22.4	23.5	23.1
Total proved reserves (million barrels of oil equivalent)[2]	249	251	278
Total proved and probable reserves (millions of barrels of oil equivalent)[3]	500	528	519
Oil, Condensate, NGLs (million barrels)[2]	120	122	145
Natural gas (billion cubic feet)[2]	770	774	797

1. Includes acquisitions and divestitures
2. 1P Reserves as per Ryder Scott year end SEC Reserve Reports
3. Kosmos reserves based on Ryder Scott Independent Reserves Report 2P (PRMS).

EBITDAX RECONCILIATION

Year Ended December 31,	2025	2024	2023
Net income (loss)	$ (699,786)	$ 189,851	$ 213,520
Exploration expenses	223,616	119,907	42,278
Depletion, depreciation and amortization	556,774	456,774	444,927
Impairment of long-lived assets	177,563	0	222,278
Equity-based compensation	27,953	37,951	42,693
Derivatives, net	(53,665)	12,099	11,128
Cash settlements on commodity derivatives	10,395	(12,488)	(16,448)
Other expenses, net	13,491	17,703	23,656
Gain on sale of assets	(2,200)	0	0
Interest and other financing costs, net	223,430	88,598	95,904
Income tax expense (benefit)	65,205	159,961	158,215
EBITDAX	$ 542,776	$ 1,070,356	$ 1,238,151

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, 2025

☐ **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	**98-0686001**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
8176 Park Lane	
Dallas, Texas	**75231**
(Address of principal executive offices)	(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 $790,254,200.

The number of the registrant's Common Stock outstanding as of February 26, 2026 was 481,024,886.

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, 2025.

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

TABLE OF CONTENTS

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).
"3.125% Convertible Senior Notes"	3.125% Convertible Senior Notes due 2030.
"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) debt modifications and extinguishments, (ix) doubtful accounts expense and (x) similar other material items which management believes affect the comparability of operating results.
"ESG"	Environmental, social, and governance.
"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.
"GNPC"	Ghana National Petroleum Corporation.
"GoA field life coverage ratio"	The "GoA field life coverage ratio" is broadly defined, as (a) total PV-10 of the Gulf of America business unit using the Proved and Probable Reserves as set forth in the most recently delivered reserve report (b) outstanding principal amount of the GoA Term Loan as of such date.
"GoA net leverage ratio"	The "GoA net leverage ratio" is broadly defined, as of any date of determination, the ratio of (a) total net debt of the Gulf of America business unit, as of such date to (b) EBITDAX of the Gulf of America business unit for the rolling period ending on such date (or in the case of any calculation of the total net leverage ratio on any date other than the last day of a rolling period, for the most recently ended rolling period for which financial statements are available).
"GoA Term Loan Facility"	Senior Secured Term Loan Credit Agreement dated September 24, 2025
"Greater Tortue Ahmeyim"	Ahmeyim and Guembeul discoveries.
"GTA Nordic bonds"	11.250% Senior Secured Notes due 2031.
"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.
"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.
"8.750% Senior Notes"	8.750% Senior Notes due 2031.
"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.
"TAG GSA"	TEN Associated Gas - Gas Sales Agreement.
"TEN"	Tweneboa, Enyenra and Ntomme.
"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 continued war in Ukraine and ongoing instability in the Middle East and Latin America 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 LNG 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 LNG 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, natural gas and LNG 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 Energy is a leading deepwater exploration and production company focused on meeting the world's growing demand for energy. We have diversified oil and gas production from assets offshore Ghana, Equatorial Guinea, Mauritania, Senegal, and the Gulf of America. Additionally, in the proven basins where we operate we are advancing high-quality development opportunities, which have come from our exploration success. Kosmos is listed on the NYSE and LSE and is traded under the ticker symbol KOS.

Kosmos was founded in 2003 to find oil and gas in under-explored or overlooked parts of West Africa. We have a history of opening new hydrocarbon basins including the discovery of the Jubilee Field offshore Ghana in 2007 and the Greater Tortue Ahmeyim Field in 2015 (which includes the Ahmeyim and Guembeul discoveries 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.

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, and bolstered by the 2018 acquisition of Deep Gulf Energy, a deepwater company operating in the Gulf of America, which further enhanced our production, exploitation and infrastructure-led exploration capabilities. Most recently, we have demonstrated infrastructure-led exploration success through the Winterfell and Tiberius discoveries in the Gulf of America in 2021 and 2023, respectively. We have demonstrated successful value-accretive acquisitions with the acquisition of additional interests in the Jubilee and TEN fields offshore Ghana in 2021 as well as the Kodiak field in the Gulf of America in 2022.

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 cost resources through acquisitions and an efficient infrastructure-led exploration program in proven basins. We are focused on increasing production, cash flows and reserves from our producing assets in Ghana, Equatorial Guinea, Mauritania, Senegal, and the Gulf of America as well as executing our appraisal and development efforts in the Gulf of America and advancing additional phases of the GTA development in Mauritania and Senegal. 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 minimizing 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 Ghana, Equatorial Guinea, Mauritania, Senegal, and the Gulf of America. In Ghana, we plan to maintain a consistent drilling program, bringing additional development wells online at the Jubilee Field in the near term, supported by high facility uptime and sustained water injection. In the Gulf of America, we plan to continue development drilling and well work in existing fields, and progressing the Tiberius project as a phased development. Offshore Mauritania and Senegal, growth is expected to be realized through additional development beyond GTA Phase 1 by fully utilizing the existing infrastructure.

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 GTA development is also being developed in a phased approach, consistent with our business strategy. Finally, our approach to discoveries in the Gulf of America 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) is an example of this approach, with development achieving first production 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 and creative 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 27 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. 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 assets in the Gulf of America 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, with a total purchase price value of approximately $2.0 billion dollars, as of the effective date of each acquisition. 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. A key attribute we seek in evaluating potential transactions is that they are cash flow accretive and strengthen the balance sheet.

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 climate change strategy, risk management, policies, targets and performance. Our TCFD (Task Force on Climate related Disclosure) aligned Sustainability Report provides more detail on our management approach to climate change across four categories: Governance, Strategy, Risk Management, and Metrics and Targets. In 2020 we set the 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. Since 2022, together with our partners, we have made significant progress to reduce routine flaring of natural gas for our non-operated assets in Ghana. Further reductions are planned in Ghana and Equatorial Guinea in 2026. In the long-term, we have set the goal to achieve and maintain top quartile carbon intensity of production in both our oil and gas portfolios, demonstrating that our climate strategy is fully aligned with our business strategy.

Maintain financial discipline

Execution of our strategy requires us to maintain a conservative financial approach with a strong balance sheet and ample liquidity. We also plan to remain proactive to ensure we have minimal near-term debt maturities and reduce leverage. As of December 31, 2025, our liquidity was approximately $342 million.

Additionally, we use derivative instruments to partially limit our exposure to fluctuations in oil prices and changes in market interest rates. 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, 2026, we have hedged positions covering approximately 7.6 million barrels of oil production in 2026 and approximately 2.0 million barrels of oil production in 2027. We also maintain insurance to partially protect against loss of production revenues from certain of our key producing assets.

Operations by Geographic Area

We currently have operations in Africa and the Gulf of America. Presently, our operating revenues are generated from our operations offshore Ghana, Equatorial Guinea, Mauritania, Senegal, and the Gulf of America. The following tables provide a summary of certain key 2025 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(1)	Depletion, depreciation and amortization per Boe
For the year ended December 31, 2025												
Jubilee	42 %	7.6	—	11.8	9.5	$ 68.26	—	3.90	$ 59.02	$ 563,548	$ 11.83	$ 18.28
TEN	5 %	1.0	—	0.6	1.1	66.30	—	3.55	62.01	68,174	68.71	2.56
Ghana	47 %	8.6	—	12.4	10.6	$ 68.04	$ —	$ 3.89	$ 59.33	$ 631,722	$ 17.70	$ 16.67
Equatorial Guinea	11 %	2.5	—	—	2.5	66.41	—	—	66.41	165,118	53.15	31.70
Mauritania|Senegal(3)	13 %	—	0.2	16.2	2.9	—	56.03	6.66	40.91	117,197	82.92	23.43
Gulf of America	29 %	5.4	0.4	3.7	6.4	65.29	18.67	3.98	58.35	374,315	23.49	36.16
Total	100 %	16.5	0.6	32.3	22.4	$ 66.89	$ 29.75	$ 5.28	$ 57.48	$ 1,288,352	$ 31.63 (2)	$ 24.84
For the year ended December 31, 2024												
Jubilee	57 %	11.5	—	12.5	13.5	$ 80.30	—	3.80	$ 71.47	$ 967,673	$ 7.94	$ 14.84
TEN	4 %	1.0	—	—	1.0	77.31	—	—	77.31	76,889	57.14	2.43
Ghana	62 %	12.5	—	12.5	14.5	$ 80.06	$ —	$ 3.80	$ 71.87	$ 1,044,562	$ 11.31	$ 14.00
Equatorial Guinea	14 %	3.4	—	—	3.4	77.66	—	—	77.66	260,675	40.63	19.42
Mauritania|Senegal	—	—	—	—	—	—	—	—	—	—	—	—
Gulf of America	24 %	4.6	0.4	3.7	5.6	75.82	20.53	2.67	65.89	370,121	24.27	32.95
Total	100 %	20.5	0.4	16.2	23.5	$ 78.70	$ 20.53	$ 3.54	$ 71.27	$ 1,675,358	$ 22.57 (2)	$ 19.43
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	—	—	—	—	—	—	—	—	—	—	—	—
Gulf of America	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

(4)

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(1) Substantially all NGLs and natural gas sales in Ghana and the Gulf of America are associated production from our oil wells and, therefore, production costs metrics are presented under a common unit of measure. Production costs per Bcf in Mauritania and Senegal was $14.68 for the year ended December 31, 2025. In Mauritania and Senegal, all condensate sales and LNG sales are associated production from our gas wells.

(2) Includes $93.4 million of pre-production operating costs for the year ended December 31, 2024 incurred before production commenced at the Greater Tortue Ahmeyim Phase 1 project in Mauritania and Senegal. Oil and gas production costs related to the LNG production at the GTA Phase 1 project were $237.6 million for the year ended December 31, 2025. First LNG was achieved in February 2025 and the first LNG cargo was successfully completed in April 2025.

(3) Mauritania and Senegal LNG sales are presented as gas sales in the table.

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

Current 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)(3)	Tullow	Production	2040	(3)
TEN	DT		20.4 %	(3)(5)	Tullow	Production	2040	(3)
Gulf of America(1)								
Barataria	MC 521		22.5 %		Kosmos	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)	
Danny Noonan	EC 381 / GB 506		30.0 %		Talos	Production	(8)	
Odd Job	MC 214 / 215		Various	(6)	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	Production	(8)	
Tiberius	KC 964		50.0 %		Kosmos	Appraisal	(8)	
Mauritania								
Greater Tortue Ahmeyim(1)	Block C8	(4)	26.8 %		BP	Production/ Development	2049(9)	
Senegal								
Greater Tortue Ahmeyim(1)	Saint Louis Offshore Profond	(4)	26.7 %		BP	Production/ Development	2044(10)	
Teranga	Cayar Offshore Profond		90.0 %	(7)	Kosmos	Appraisal	2026	
Yakaar	Cayar Offshore Profond		90.0 %	(7)	Kosmos	Appraisal	2026	
Equatorial Guinea								
Ceiba Field and Okume Complex(1)	Block G		40.4 %		Trident	Production	2040	

(1) For information concerning our estimated proved reserves as of December 31, 2025, 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 Ghana partnership received Government approval in December 2025 for the license extension for its WCTP and DT Petroleum Agreements, which cover the Jubilee and TEN fields, to 2040. As part of the extensions, starting from July 2036, Ghana National Petroleum Corporation's share in the fields will increase by an additional 10% interest and the joint venture partners' shares will decrease pro rata.

(4) 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.

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

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

(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 Gulf of America 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	2	52.0%	(1)	Kosmos, Panoro	2026	
Sao Tome and Principe	1	58.9%	(2)	Kosmos	2026	
Senegal	1	90.0%	(3)	Kosmos	2026	
Gulf of America	36	38.6%		Kosmos, Occidental, Beacon, Harbour, Murphy, Talos, W&T Offshore, Shell	through 2034	(4)

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(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) 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.

(3) 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.

(4) Our Gulf of America 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 2034.

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. 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. Following completion of the acquisition and pre-emption process, Kosmos’ interest in the Jubilee Unit Area is 38.6% and Kosmos’ interest in the TEN Fields is 20.4%. The following is a brief discussion of our discoveries on our license areas offshore Ghana.

In June 2025, the Jubilee and TEN partnerships entered into a Memorandum of Understanding with the Government of Ghana to extend the WCTP and the DT licenses. The Ghana partnership received Government approval in December 2025 for the license extensions, which cover the Jubilee and TEN fields. Accordingly, the WCTP and DT licenses have been extended to 2040, and starting from July 2036, Ghana National Petroleum Corporation’s share in the fields will increase by an additional 10% interest and the joint venture partners’ shares will decrease pro rata. As part of the extension of the Petroleum Agreements, the Jubilee plan of development is amended to include up to twenty additional wells in the field.

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 an original duration of 30 years from its effective date (July 2004), which has now been extended to 2040.

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 an original duration of 30 years from its effective date (July 2006), which has now been extended to 2040.

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 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 partnership completed a new 4D seismic survey on the Jubilee and TEN Fields during the first quarter of 2025 and an OBN survey was completed in the fourth quarter of 2025. In December 2024, the partnership entered into a drilling rig contract for the next development drilling campaign in the Jubilee Field, which commenced in the second quarter of 2025. The partnership successfully brought one producer well online in July 2025. After undergoing scheduled maintenance, the rig returned to the field and drilled an additional producer well in the Jubilee Field, which was successfully completed and brought online in January 2026. The campaign is planned to include the drilling and completion of an additional four producer wells and an additional water injector well in 2026.

In Ghana, we currently produce associated gas from the Jubilee and TEN Fields. A gas pipeline from the Jubilee Field transports such natural gas onshore for processing and sale. In 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 through May 2024. This interim gas sales agreement was subsequently extended to November 2025 at a price of approximately $3.00 per MMBtu. In December 2025, as part of the extension of the WCTP and DT Petroleum Agreements, the Ghana partners and Government of Ghana have approved an amended gas sales agreement at a price of $2.50 per MMBtu through the extended expiration date of 2040 for the WCTP and DT licenses. 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.

Gulf of America

In the Gulf of America, Kosmos maintains: (i) a portfolio of producing assets that we plan to 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 Gulf of America Federal lease sales and farm-in transactions.

The following is a brief discussion of our key fields in the Gulf of America.

Odd Job

The Odd Job Field is producing from three Middle Miocene wells through the Delta House FPS, operated by Murphy. To sustain long-term production from the field, we installed a subsea pump in the field in 2024.

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 Gulf of America, 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”).

Winterfell

The Winterfell Field is producing from two wells in the Upper Miocene sands.The initial two production wells of the first phase were brought online in the third quarter of 2024 and the Winterfell-3 well was brought online in October 2024. Shortly after startup of the third well, production at the field was curtailed due to sand production from the third well seen at the production facility. In December 2024, production from Winterfell-1 and Winterfell-2 was restored. Remediation work on Winterfell-3 was performed in the first quarter of 2025, however, it was unsuccessful. During the second quarter, the partnership drilled the Winterfell-4 step out well to test a separate fault block and define the eastern extent of the Winterfell reservoir area. The Winterfell-4 well was abandoned in September 2025 by the operator due to challenges during the completion operations arising from the collapse of the production casing. The partnership will continue to review alternative options to access those resources with near-term activity in 2026 focused on restoring production from the Winterfell-3 fault block.

Tiberius

In July 2023, Kosmos spud a well to test the Tiberius infrastructure-led exploration prospect, which is located in block 964 of Keathley Canyon (33.3% 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. In March 2024, Kosmos completed the acquisition of an additional 16.7% participating interest in the Tiberius area in Keathley Canyon Blocks 920 and 964 offshore Gulf of America. As a result of the transaction, Kosmos’ participating interest in Tiberius was increased from 33.3% to 50.0%. Kosmos continues to progress the development plan with our partner Occidental Petroleum Corporation (“Oxy”) (50% working interest). A production handling agreement for the Oxy-Operated Lucius platform was signed in the third quarter of 2025. Final investment decision and a farm down to reduce Kosmos’ working interested are expected in the first half of 2026.

Mauritania

In June 2012, we entered into an exploration and production contract covering offshore Mauritania Block C8 with the Islamic Republic of Mauritania. Petroleum cost recovery is apportioned to the contractor from up to 55% for oil and 62% for gas of total production prior to petroleum profits being split between the Government of Mauritania and the contractor. Petroleum profits are 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.

The C8 block is located on the western margin of the Mauritania Salt Basin offshore Mauritania and ranges in water depths from 100 to 3,000 meters. We have drilled one successful exploration well and one appraisal well in our existing Block C8 acreage (now Greater Tortue Ahmeyim).

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.

The exploration period of the St. Louis Offshore Profound license expired in July 2021. The current phase of the Cayar Block exploration license expires in July 2026. We have drilled two successful exploration wells (Yakaar-1 and Teranga-1) and one successful appraisal well (Yakaar-2) in the Cayar Offshore Profound Block. Kosmos has worked with PETROSEN on potential development concepts for the field, along with identifying a suitable partner. Given we have not been able to attract a suitable partner and agree a commercially attractive development concept with the government of Senegal, we are working with PETROSEN to withdraw from the block.

Greater Tortue Ahmeyim (GTA) Development

The Greater Tortue Ahmeyim Field, discovered by the Tortue-1 well in May 2015 (in Mauritania Block C8) and by the Guembeul-1 well in January 2016 (in the Senegal Saint-Louis Offshore Profond Block) 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 were 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 granting the partnership the right to develop and produce gas for an initial period of twenty-five years in Senegal, or 2044, and thirty years in Mauritania, or 2049. The exploration authorizations may be extended by up to twenty years in Senegal and up to ten years in Mauritania.

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 GTA development, Tortue-1, Guembeul-1, Ahmeyim-2 and Greater Tortue Ahmeyim-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.

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 appraisal well, drilled on the eastern anticline within the unit development area of Greater Tortue Ahmeyim field, 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 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 Phase 1 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 at a nameplate capacity of approximately 2.7 million tons per annum. The project provides LNG for global export, and is also planned to 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 GTA Phase 1, and the Tortue Phase 1 SPA was executed in February 2020 with an initial term through the end of 2033 with a seller's option to extend the term for an additional 10 years.

First gas production from the subsea system was achieved on December 31, 2024. First LNG was achieved in February 2025 and the first gross LNG cargo was successfully exported in April 2025. Eighteen and a half gross LNG cargos and one condensate cargo were lifted in 2025. The Gimi FLNG vessel Commercial Operations Date was achieved in the second quarter of 2025 with successful ramp-up to the daily contracted sales volume level under the Tortue Phase 1 SPA, equivalent to approximately 2.45 million tonnes per annum. Additionally, the Gimi FLNG vessel operated at nameplate capacity in December 2025, reaching a peak production rate of approximately 3.0 million tonnes per annum. Further phases of GTA are expected to increase production through the full utilization of the existing infrastructure.

Equatorial Guinea

As described in Item 7 of this Form 10-K, on February 24, 2026, we entered into a Share Sale and Purchase Agreement with a subsidiary of Panoro Energy ASA for the sale of all of our participating interest in the Ceiba Field and Okume Complex production assets located in Block G offshore Equatorial Guinea. The transaction has received approval from the Government of Equatorial Guinea and completion only remains subject to CEMAC customary approval. While we expect to close the transaction around the middle of 2026, there can be no assurances that closing will ultimately occur or that it may not be delayed. As such, the Company has elected to report on the business throughout this Form 10-K on the basis that the transaction has not yet closed and that the Company continues to own all of the participating interest in the Ceiba Field and Okume Complex production assets located in Block G offshore Equatorial Guinea. All such references to the Company's future plans and expectations for the Equatorial Guinea business unit should therefore be read in light of the ongoing transaction.

In June 2018, we closed a farm-in agreement for Block EG-24, offshore Equatorial Guinea, whereby we acquired a 40% non-operated participating interest. In the first quarter of 2019, we acquired the remaining interest in and operatorship of the block, which resulted in Kosmos owning an 80% participating interest in Block EG-24. The Equatorial Guinean national oil company, GEPetrol, currently has a 20% carried interest during the exploration period. 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 December 2022, we received formal approval from the Ministry of Hydrocarbons and Mining Development to enter the second sub-period of the exploration phase of Block EG-24. In October 2025, we received approval of an extension of the second sub-period to December 2026. Block EG-24 currently comprises approximately 874,012 acres (3,537 square kilometers) and is 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.

Ceiba Field and Okume Complex

In Equatorial Guinea, we maintain a 40.4% undivided participating interest in the Ceiba Field and Okume Complex. Trident is the operator of the Ceiba Field and Okume Complex. These offshore assets in the Gulf of Guinea provide cash flow through production.

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 Hydrocarbons and Mining Development 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. Under the Block G petroleum contract, Kosmos is required to pay to the Ministry of Hydrocarbons and Mining Development of Equatorial Guinea a percentage of production as a royalty, currently 11%. These royalties are to be paid in-kind or, at the election of the Ministry of Hydrocarbons and Mining Development of Equatorial Guinea, in cash. A corporate tax rate of 35% is applied to profits at a country level through December 31, 2024. In the fourth quarter of 2024, the corporate tax rate in Equatorial Guinea was reduced from 35% to 25%, with an effective date of January 1, 2025.

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 527,000 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 May 2025, we received approval to extend the current exploration phase for Block 5 offshore Sao Tome and Principe to May 2026.

Our Reserves

The following table sets forth summary information about our estimated proved reserves as of December 31, 2025. 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, 2025, 2024, and 2023 were associated with our fields in Ghana, Equatorial Guinea, Mauritania, Senegal and the Gulf of America.

Summary of Oil and Gas Reserves

	2025 Net Proved Reserves(1)			2024 Net Proved Reserves(1)			2023 Net Proved Reserves(1)		
	Oil, Condensate, NGLs(5)	Natural Gas(3)	Total	Oil, Condensate, NGLs(5)	Natural Gas(3)	Total	Oil, Condensate, NGLs(5)	Natural Gas(3)	Total
	(MMBbl)	(Bcf)	(MMBoe)	(MMBbl)	(Bcf)	(MMBoe)	(MMBbl)	(Bcf)	(MMBoe)
Reserves Category									
Proved developed									
Ghana(2)	32	76	45	39	75	52	46	79	60
Equatorial Guinea	12	6	13	17	11	19	19	16	22
Mauritania|Senegal	4	358	64	—	—	—	—	—	—
Gulf of America	15	9	17	18	11	19	15	12	17
Total proved developed	63	449	138	74	97	90	81	106	99
Proved undeveloped									
Ghana(2)	53	60	63	37	40	44	47	56	56
Equatorial Guinea	—	—	—	1	—	1	5	—	5
Mauritania|Senegal	3	258	46	7	632	113	7	628	112
Gulf of America	2	2	2	3	5	3	6	6	7
Total proved undeveloped(4)	57	321	111	48	677	161	64	690	179
Total Kosmos proved reserves	120	770	249	122	774	251	145	797	278

(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.

(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. Our natural gas reserves in Ghana include natural gas forecasted to be sold to the Government of Ghana.

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 Phase 1 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, 18.5 Bcf and 19.9 Bcf for 2025, 2024 and 2023, 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 50.2 Bcf, 55.8 Bcf and 52.3 Bcf in 2025, 2024 and 2023, respectively. For the Gulf of America, total proved natural gas reserves include fuel gas of approximately 0.6 Bcf, 1.9 Bcf and 1.1 Bcf for 2025, 2024, and 2023, respectively.

(4) Proved undeveloped reserves as of December 31, 2025 expected to be developed beyond five years since initial disclosure are all related to long-term projects which will be developed under a continuous drilling program primarily including the additional wells at Jubilee under the amended plan of development and the Greater Tortue Ahmeyim Phase 1 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, 2025 at Jubilee resulted in an overall increase of 13.5 MMBoe. Jubilee net production of 10.5 MMBoe was offset by the positive revision of 20.2 MMBoe based on the license extension and Petroleum Agreement amendments, facilitating additional field development. The change to the Gas Sales Agreement (GSA) resulted in a positive revision of 3.8 MMBoe. There were no changes related to the commodity price effect in Jubilee. The TEN net production for the December 31, 2025 was 1.3 MMBoe. Changes at TEN include a negative revision of 0.5 MMBoe due to performance, for an overall decrease in reserves of 1.8 MMBoe. We note that there were no changes related to the commodity price effect.

The overall net reserves at Equatorial Guinea decreased by 7.3 MMBoe. Changes at Equatorial Guinea included negative revisions of 1.3 MMBoe due to loss of uneconomic PUD volumes in Ceiba and 0.1 MMBoe due to performance, in addition to the net production of 2.8 MMBoe. The commodity price effect caused a negative revision of 3.4 MMBoe in Equatorial Guinea.

Changes in Mauritania and Senegal include a positive revision of 8.8 MMBoe due to increase in the annual production capacity from 2.45 to 2.7 MTPA for the duration of the field life based on realized production volumes and operator plan for the Greater Tortue Ahmeyim Phase 1 project. This increase is offset by a negative revision of 8.5 MMBoe due to the delay in initial production and ramp up at the beginning of Sale and Purchase Agreement (SPA) term, as well as the net 2025 production of 3.2 MMBoe and a fixed contract length that supports proved reserves recognition. There were no changes related to the commodity price effect on reserves in Mauritania and Senegal. The overall net reserves at Mauritania and Senegal decreased by 2.8 MMBoe.

Changes at the Gulf of America include a positive revision of 6.4 MMBoe driven primarily by the performance in Kodiak, Tornado, and Odd Job, partially offset by a negative change of 2.5 MMBoe due to Winterfell performance. An update to the future development plans for Marmalard caused a negative revision of 1.4 MMBoe. The Gulf of America net production for the year ended December 31, 2025 was 6.4 MMBoe for an overall reserves decrease of 4.0 MMBoe. The changes related to the commodity price effect in the Gulf of America were immaterial.

During the year ended December 31, 2025, we had an overall proved undeveloped reserves decrease of 50.4 MMBoe primarily due to the conversion of proved undeveloped reserves to proved developed reserves during 2025 related to the startup of three wells in Greater Tortue Ahmeyim Phase 1 project (-63.9 MMBoe), the drilling of two wells in Greater Jubilee (-16.7 MMBoe), and and sidetracking a well in Marmalard (-0.3 MMBoe). Changes to the plan of development in Marmalard (-1.4 MMBoe) and loss of Ceiba uneconomic PUD volumes (-1.3 MMBoe) resulted in additional proved undeveloped reserve decreases. The license extension and Petroleum Agreement amendments in Greater Jubilee, facilitating additional field development, and an update to the GSA (+35.6 MMBoe) as well as a positive revision driven by an addition of a sidetrack in Winterfell (+0.6 MMBoe) partially offset the overall decrease in proved undeveloped reserves.

In Ghana, we converted 16.7 MMBoe of proved undeveloped reserves to proved developed with the drilling of two wells in Jubilee at a cost of approximately $61.0 million. In Mauritania and Senegal, we spent approximately $49.1 million related to the completion of the first phase of the Greater Tortue Ahmeyim development. With the start up of production in the Greater Tortue Ahmeyim Phase 1 project, 63.9 MMBoe of proved undeveloped reserves were converted to proved developed via three previously drilled wells. In the Gulf of America, we converted 0.3 MMBoe with the sidetracking of a well in Marmalard at a cost of $6.2 million.

Changes during the year ended December 31, 2024 at Jubilee resulted in an overall decrease of 16.1 MMBoe. Jubilee net production of 14.0 MMBoe was the largest contributing factor to the decrease. Also impacting reserves were negative revisions of 7.5 MMBoe due to field performance primarily related to the J-69 & J-68 wells, partially offset by the positive revision of 5.4 MMBoe due to drilling of two wells that had no prior proved recognition. There were no changes related to the commodity price effect in Jubilee. Changes at TEN include a negative revision of 2.5 MMBoe, primarily driven by removal of future development opportunities from the TEN Fields. The TEN net production for the December 31, 2024 was 1.5 MMBoe, for an overall decrease in reserves of 4.0 MMBoe. We note that the overall gas reserves did not change significantly in TEN and that there were no changes related to the commodity price effect. Changes at Equatorial Guinea included a negative revision of 3.0 MMBoe primarily due to loss of uneconomic PUD volumes in Okume, in addition to the net production of 3.4 MMBoe. The overall net reserves at Equatorial Guinea decreased by 6.4 MMBoe. There were no changes related to the commodity price effect on reserves in Equatorial Guinea. Changes in Mauritania and Senegal include a small positive revision of 0.9 MMBoe due to change in the calculated net reserves amount based on the updated economic parameters as part of the petroleum contract calculations. There were no changes related to the commodity price effect on reserves in Mauritania and Senegal. Changes at the Gulf of America include a positive revision of 3.5 MMBoe primarily driven by the Winterfell performance and an updated plan of development for Marmalard. There was also an extension of 1.2 MMboe in the Winterfell field based on the results of the drilled Winterfell-3 well. The Gulf of America net production for the year ended December 31, 2024 was 5.6 MMBoe for an overall reserves decrease of 0.9 MMBoe. The changes related to the commodity price effect in the Gulf of America were immaterial.

During the year ended December 31, 2024, we had an overall proved undeveloped reserves decrease of 18.0 MMBoe primarily due to the conversion of proved undeveloped reserves to proved developed reserves during 2024 related to the drilling of three wells in Jubilee (-16.3 MMBoe), the drilling of two wells in Equatorial Guinea (-1.8 MMBoe), completing two Winterfell wells (-2.9 MMBoe) and the installation of the subsea pump in Odd Job (-1.4 MMBoe). Additionally, we had increases to proved undeveloped reserves during the ended December 31, 2024 including from the optimization of future well forecasts in Jubilee (+7.1 MMBoe), a change in the calculated net reserves amount based on the updated economic parameters as part of the petroleum contract calculations of the Greater Tortue Ahmeyim Phase 1 project (+0.9 MMBoe), the addition of two undeveloped wells in Ceiba (+1.3), and the addition of two undeveloped wells in Marmalard (+1.0 MMBoe), offset by the removal of additional planned development in TEN (-3.2 MMBoe) and removal of Okume uneconomic PUD volumes (-2.7 MMBoe).

In Ghana, we converted 16.3 MMBoe of proved undeveloped reserves to proved developed with the drilling of three wells in Jubilee at a cost of approximately $42.6 million. We also drilled two wells at a cost of $62.7 million that did not convert proved developed reserves as the wells did not have any proved recognition in the prior year. In Equatorial Guinea, we converted 1.8 MMBoe of proved undeveloped reserves to proved developed reserves at a cost of $142.6 million by drilling of two wells. In Mauritania and Senegal, we spent approximately $310.9 million progressing the Greater Tortue Ahmeyim Phase 1 project. In the Gulf of America, we converted 1.4 MMBoe at a cost of approximately $42.6 million with the installation of the subsea pump in Odd Job. In addition, we converted 2.9 MMBoe with the completion of two wells in the Winterfell Field at a cost of $78.9 million.

Changes during the year ended December 31, 2023 at 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 Gulf of America 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 Gulf of America 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 Gulf of America 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 Gulf of America 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 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. In the Gulf of America, 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.

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, 2025, 2024 and 2023 has been prepared by RSC, our independent petroleum 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 petroleum 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, 2025 are based on costs in effect at December 31, 2025 and the 12-month unweighted arithmetic average of the first-day-of-the-month price for the year ended December 31, 2025, 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 petroleum engineers for the years ended December 31, 2025, 2024 and 2023, was established in 1937. For over 85 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, 2025, 2024 and 2023, 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, 2025, 2024 and 2023 and related future net revenues and PV-10 at December 31, 2025, 2024 and 2023 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, 2025 reserve report was completed on February 6, 2026, and a copy is included as an exhibit to this report.

In connection with the preparation of the December 31, 2025, 2024 and 2023 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 would 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, 2025, 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 80 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 40 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 25 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 and meets with the senior RSC representative outside the presence of any Company representatives on an annual basis to discuss RSC's reserve assessment process in the preparation of their reserves estimates. In addition, our Reservoir Engineering team meets with representatives of our independent petroleum 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, 2025 for the countries in which we currently operate.

	Developed Area (Acres)		Undeveloped Area (Acres)		Total Area (Acres)		Current Phase Exploration
	Gross	Net(1)	Gross	Net(1)	Gross	Net(1)	Range
	(In thousands)						
Ghana(2)	164	43	33	9	197	52	— (2)
Equatorial Guinea	65	26	1,184	799	1,249	825	2026
Mauritania	129	35	—	—	129	35	—
Sao Tome and Principe	—	—	527	310	527	310	2026
Senegal	129	34	788	709	917	743	2026
Gulf of America(3)	85	26	121	46	206	73	through 2034 (3)
Total	572	164	2,653	1,873	3,225	2,038	

(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. Additionally, the Ghana partnership received Government approval in December 2025 for the license extension for its WCTP and DT Petroleum Agreements, which cover the Jubilee and TEN fields, to 2040. As part of the extensions, starting from July 2036, Ghana National Petroleum Corporation's share in the fields will increase by an additional 10% interest and the joint venture partners' shares will decrease pro rata. 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 Gulf of America 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 2034.

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, 2025:

	Productive Oil Wells		Productive Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Ghana(2)	65	21.82	—	—	65	21.82
Equatorial Guinea	78	31.51	—	—	78	31.51
Mauritania|Senegal	—	—	3	0.80	3	0.80
Gulf of America(2)	18	5.47	—	—	18	5.47
Total(1)	161	58.80	3	0.80	164	59.60

(1) Of the 164 productive wells, 47 (gross) or 16 (net) have multiple completions within the wellbore.

(2) Table above reflects our additional interests acquired in Ghana and Gulf of America. In Ghana, the partnership received Government approval in December 2025 for the license extension for its WCTP and DT Petroleum Agreements, which cover the Jubilee and TEN fields, to 2040. As part of the extensions, starting from July 2036, Ghana National Petroleum Corporation's share in the fields will increase by an additional 10% interest and the joint venture partners' shares will decrease pro rata.

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, 2025														
Ghana	—	—	—	—	—	—	1	0.39	—	—	1	0.39	1	0.39
Gulf of America(4)	—	—	1	0.25	1	0.25	—	—	—	—	—	—	1	0.25
Total	—	—	1.00	0.25	1	0.25	1	0.39	—	—	1	0.39	2	0.64
Year Ended December 31, 2024														
Ghana	—	—	—	—	—	—	4	1.54	—	—	4	1.54	4	1.54
Equatorial Guinea	—	—	1	0.43	1	0.43	2	0.81	—	—	2	0.81	3	1.24
Gulf of America	1	0.25	—	—	1	0.25	1	0.25	—	—	1	0.25	2	0.50
Total	1	0.25	1	0.43	2	0.68	7	2.60	—	—	7	2.60	9	3.28
Year Ended December 31, 2023														
Ghana	—	—	—	—	—	—	7	2.70	—	—	7	2.70	7	2.70
Gulf of America	1	0.25	—	—	1	0.25	1	0.11	—	—	1	0.11	2	0.36
Mauritania|Senegal	—	—	—	—	—	—	1	0.27	—	—	1	0.27	1	0.27
Total	1	0.25	—	—	1	0.25	9	3.08	—	—	9	3.08	10	3.33

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(1) As of December 31, 2025, two 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 ten 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) Includes the Winterfell-4 well which is considered a step out well from an accounting perspective, but was drilled as part of the Winterfell phased 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, 2025.

	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 G	—	—	—	—	—	—	1	0.40
Gulf of America								
Tiberius	—	—	—	—	1	0.50	—	—
Mauritania / Senegal								
Greater Tortue Ahmeyim	—	—	—	—	1	0.27	—	—
Total	—	—	1	0.39	2	0.77	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. 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 through May 2024. This interim gas sales agreement was subsequently extended to November 2025 at a price of approximately $3.00 per MMBtu. In December 2025, as part of the extension of the WCTP and DT Petroleum Agreements, the Ghana partners and Government of Ghana have approved an amended gas sales agreement at a price of $2.50 per MMBtu through the extended expiration date of 2040 for the WCTP and DT licenses.

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. Natural gas is sold monthly to the Government of Ghana through an interim gas sales agreement. In December 2025, the Ghana partners and Government of Ghana have approved an amended gas sales agreement at a price of $2.50 per MMBtu through the extended expiration date of 2040 for the WCTP and DT licenses. A gas pipeline from the Jubilee Field transports such natural gas onshore for processing and sale. 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 Gulf of America, Kosmos has historically sold crude oil on monthly contracts to various purchasers. Currently, Kosmos sells GoA oil production exclusively to a single buyer on a multi-year term deal. GoA crude oil sales take place monthly 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. 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.

In Mauritania and Senegal, we sell our entitlement share of LNG production from the Greater Tortue Ahmeyim Field free on board (FOB) under the Tortue Phase 1 SPA with BPGM which was signed in February 2020. 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 through the end of 2033, which can be extended by a further ten years at the sellers' option. As provided under the GTA UUOA and the C8 and Saint-Louis Offshore Profond petroleum contracts, we are entitled to lift and sell our share of condensate production from the Greater Tortue Ahmeyim Field. Condensate cargos are typically sold to purchasers with the sale taking place offshore Mauritania and Senegal on the spot market. LNG volumes in excess of the annual contract quantity of 2.45 mtpa associated with existing infrastructure are also sold to BPGM.

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 economic disruption resulting from Russia's continued war in Ukraine, ongoing instability in the Middle East and Latin America, 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.

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 continued war in Ukraine, ongoing instability in the Middle East and Latin America, 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 $60 to $83 per barrel during 2025. HLS crude, the benchmark for the majority of our Gulf of America oil sales, which generally trades at a discount to Dated Brent, ranged from approximately $57 to $83 during 2025. Excluding the impact of hedges, our realized oil price for 2025 was $66.89 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 remains strong. 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, and liability insurance including pollution liability to cover pollution from wells and other operations. 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, respectively, of (i) the Jubilee Unit and the TEN Fields offshore Ghana, (ii) the Greater Tortue Ahmeyim Field 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.

Gulf of America (Operated and Non-operated)

After the major well control incident and oil release in the Gulf of America 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 Gulf of America 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 water 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 Associates ("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 Gulf of America.

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 Vice President of Administration. Our Senior Director of Information Technology (IT), the technical lead of our IT department, reports directly to the Vice President of Administration. Our Vice President of Administration and our Senior Director of IT receive reports from our information technology team and monitors the prevention, detection, mitigation, and remediation of cybersecurity incidents. Our IT leadership and dedicated personnel are certified and experienced information systems security professionals and information security managers with many years of experience. Management, including the Vice President of Administration, 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 2025, 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 2025 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.

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, 2025, we had 216 employees with 175 being based in the United States and 41 residing in our foreign offices. Our workforce was approximately 40% 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 gas reserves;
- We may not be able to commercialize our interests in some of the 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, development, 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 have had, and may in the future have, disagreements with certain host governments and contractual counterparties regarding certain of our rights and responsibilities;
- The geographic locations of our licenses in Africa and the Gulf of America 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, natural gas and LNG 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, natural gas, and LNG 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 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, GoA Term Loan Facility, the bond terms governing our GTA Nordic bonds and the indentures governing our Senior Notes and Convertible 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 and Convertible 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 cybersecurity incident, including a breach of digital security, could result in information theft, data corruption, operational disruption, and/or financial loss;
- We are incorporating artificial intelligence technologies into our processes and these technologies may present business, operational, compliance, cybersecurity, and reputational risks;
- 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 Gulf of America 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 activism;
- 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, 3D and 4D 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. 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 Gulf of America. 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, 2025, we have a commitment to one development well in Equatorial Guinea. Additionally, as part of the recent extension of the Petroleum Agreements covering the Jubilee and TEN fields, the Jubilee plan of development is amended to include up to twenty additional wells in the field, with a commitment to drill a minimum of ten additional wells. 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 units 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, natural gas and LNG 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. We have joint interest receivables, domestic gas payment receivables, and project development carries in Ghana, Mauritania and Senegal, and our counterparties under these agreements may have difficulty in paying amounts due to Kosmos. 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. Following an initial redetermination process completed on October 14, 2011, 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 in October 2021 and completion of the subsequent pre-emption by Tullow in March of 2022, Kosmos' interest in the Jubilee Unit Area now stands at 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 Gulf of America 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 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 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, 2025.

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, natural gas and LNG prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil, natural gas and LNG prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and 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, natural gas and LNG 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 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 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, natural gas and LNG;
- 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 some of the 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 the 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 transports such natural gas onshore for processing and sale. During 2023, the Jubilee partners reached an interim agreement to sell Jubilee Field gas to the Government of Ghana through May 2024. This interim gas sales agreement was subsequently extended to November 2025 at a price of approximately $3.00 per MMBtu. In December 2025, as part of the extension of the WCTP and DT Petroleum Agreements, the Ghana partners and Government of Ghana have approved an amended gas sales agreement at a price of $2.50 per MMBtu through the extended expiration date of 2040 for the WCTP and DT licenses. Our inability to 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.

In Mauritania and Senegal, while we currently only export our gas resource to the LNG market, we also intend to utilize existing facilities for domestic gas delivery. This plan is contingent signing gas sales agreements for domestic gas and the necessary infrastructure to transport the gas to domestic onshore markets being constructed. 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 depends 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 continued access to drilling rigs and construction vessels suitable for the environment in which we operate and on operating infrastructure that allows us to commercially process and market our products. 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, vessels or other operating infrastructure 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.

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, natural gas, and LNG 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, natural gas, and LNG 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, natural gas, and LNG, 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 Gulf of America, 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 Gulf of America 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 have had, and may in the future have, disagreements with certain host governments and contractual counterparties regarding certain of our rights and responsibilities.

There can be no assurance that 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.

The geographic locations of our licenses in Africa and the Gulf of America 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 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, natural gas and LNG prices may adversely affect our business, financial condition and results of operations.

The prices that we will receive for our oil, natural gas, and LNG 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, natural gas and LNG prices experienced significant volatility in the past few years and will likely continue to be volatile in the future. For example, Russia's continued war in Ukraine, ongoing instability in the Middle East and Latin America, 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, natural gas and LNG 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, natural gas, and LNG;
- 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 in oil producing nations such as Venezuela and Iran;
- 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 and LNG that we can produce economically. A substantial or extended decline in oil, natural gas, and LNG 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, natural gas and LNG 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 Gulf of America. 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, natural gas, and LNG 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;
- inflationary pressures leading to increasing costs;
- 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. 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 Gulf of America. 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, natural gas, and LNG 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 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, natural gas, and LNG 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, natural gas, and LNG 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.

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 such as COVID-19, 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, such as the Ebola virus 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.

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 in response to outbreaks of disease 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 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. For example, recent increases in the cost of insurance coverage in the Gulf of America for Oil Spill Financial Responsibility requirements under the Oil Pollution Act of 1990 may result in Kosmos carrying lower insurance coverage than in previous years. 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, increased tariffs 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. Disruptions and volatility in the global financial markets may lead to an increase in interest rates 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, natural gas and LNG, 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 have and may in the future enter into derivative arrangements 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, natural gas and LNG 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, GoA Term Loan Facility, the bond terms governing our GTA Nordic bonds and the indentures governing our Senior Notes and Convertible 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, GoA Term Loan Facility, the bond terms governing our GTA Nordic bonds and the indentures governing our Senior Notes and Convertible 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, GoA Term Loan Facility, the bond terms governing our GTA Nordic bonds or the indentures governing our Senior Notes and Convertible 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 GoA Term Loan Facility, our capital expenditures that we can fund with the proceeds of our commercial debt facility and GoA Term Loan Facility.

Our commercial debt facility, the bond terms governing our GTA Nordic bonds and GoA Term Loan Facility require us to maintain certain financial ratios, such as asset coverage ratios, 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, GoA Term Loan Facility, the bond terms governing our GTA Nordic bonds and the indentures governing our Senior Notes and Convertible 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, GoA Term Loan Facility, the bond terms governing our GTA Nordic bonds and the indentures governing our Senior Notes and Convertible 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, GoA Term Loan Facility, the bond terms governing our GTA Nordic bonds and the indentures governing our Senior Notes and Convertible 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 and Convertible Senior Notes could discourage an acquisition of us by a third-party.

Certain provisions of the indentures governing our Senior Notes and Convertible 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. In addition, upon the occurrence of a "fundamental change" (as defined in the indenture governing our Convertible 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, 2025, we had $1,200.0 million outstanding and $150.0 million of committed undrawn available capacity under our commercial debt facility. As of December 31, 2025, we had $1.8 billion principal amount of Senior Notes and Convertible Senior Notes outstanding and $150 million outstanding under the GoA Term Loan Facility. 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, natural gas, and LNG 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 and Convertible 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 and Convertible 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 and Convertible 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 and Convertible 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 and Convertible Senior Notes limit 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 and Convertible 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, natural gas and LNG 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 cybersecurity 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 applications 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, cybersecurity 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 personal, confidential or proprietary 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 personal, confidential or proprietary 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 personal, confidential, proprietary and other information, or other disruption of our business operations. In addition, certain cybersecurity incidents, such as surveillance, may remain undetected for an extended period. A cybersecurity 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 cybersecurity 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.

We are incorporating artificial intelligence technologies into our processes and these technologies may present business, operational, compliance, cybersecurity, and reputational risks.

Our business increasingly utilizes artificial intelligence ("AI"), machine learning, and automated decision making to improve our internal processes and support operational and strategic decisions. The development, deployment and use of these technologies, combined with an evolving and uncertain regulatory environment, may result in new or heightened governmental or regulatory scrutiny, litigation, confidentiality or security risks, reputational harm, liability or other adverse consequences to our business operations, any of which could adversely affect our business, financial condition and results of operations.

The use of AI tools can lead to unintended consequences, including the unauthorized use or disclosure of confidential and proprietary information, or the generation of content or outputs that appear correct but are factually inaccurate, misleading, or otherwise flawed. Reliance on such outputs could expose us to risks related to inaccuracies or errors in the output of such technologies. We have established an internal, cross-functional AI committee to oversee and guide our AI strategy including evaluating the costs, benefits, risks, and opportunities associated with the use of AI tools in our business and recommending mitigation measures, as well as developing and implementing an AI use policy across the Company. However, these governance measures may not be effective in all cases, and it is not possible to predict or prevent all of the risks related to the use of AI, machine learning, and automated decision making technologies. In addition, future changes in laws or developments in the regulatory frameworks governing the use of such technologies and in related stakeholder expectations could restrict or limit our use of AI, increase our compliance costs, or subject us to liability, any of which could adversely affect our ability to develop and use such technologies.

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

Our ability to use our federal and international 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, with regard to our U.S. net operating losses only, 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.

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.

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 attempted imposition of or the implementation or realization of any of the foregoing could have an adverse impact on our financial condition and results of operations. For example, compliance with West African Monetary Union Regulations in Senegal could result in our exposure to, among other things, foreign exchange risks/costs and impact the efficiency of moving cash balances in and out of country.

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 Gulf of America has materially increased costs and delays in offshore oil and natural gas exploration and production operations.

In the Gulf of America, 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 Gulf of America. These regulatory initiatives have, at various times, effectively slowed down the pace of drilling and production operations in the Gulf of America 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 revised requirements for well design, well control, casing, cementing, real-time monitoring (RTM), and subsea containment. These revisions modified 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. Since adoption of the 2019 rule, BSEE has adopted additional well control requirements and continues to evaluate and implement further regulatory initiatives applicable to offshore oil and gas operations through amendments, guidance and ongoing or anticipated rulemakings.

In addition to the array of new or revised safety, permitting and certification requirements developed and implemented by the DOI in recent years, there have been a variety of proposals and initiatives to change existing laws, regulations and agency practices that could affect offshore development and production, such as, for example, proposals to increase or otherwise revise the minimum financial responsibility or other security required under the Oil Pollution Act of 1990 or otherwise applicable to offshore lessees and operators. Regulatory initiatives relating to financial assurance, bonding and other forms of security continue to evolve. For example, in 2024, the DOI finalized an offshore financial assurance rule that increased bonding and other financial responsibility requirements for certain offshore lessees and operators. In 2025, the DOI announced plans to revise this rule as part of a broader review of offshore financial assurance requirements. Any changes to the rule, or uncertainty regarding its implementation, could affect our financial assurance obligations, compliance costs and offshore development activities.

To the extent the existing regulatory initiatives implemented and pursued in recent years or any future restrictions, whether through legislative or regulatory means or increased or broadened permitting and enforcement programs, foster uncertainties, delays or increased costs 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 that impose more stringent requirements regarding financial assurances, restrict or delay leasing or permitting or that otherwise adversely affect our offshore activities could result in increased costs, 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.

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 continuing attention to climate change and energy transition issues. 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. In January 2026, President Trump once again withdrew the United States from the Paris Agreement, as he did during his first term. 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 report large methane emissions to the EPA. Relatedly, in November 2024, the U.S. EPA finalized a rule implementing the Waste Emissions Charge, a fee for large emitters of methane if their emissions exceed certain levels, as required by the Inflation Reduction Act. In addition, numerous other climate change and GHG emissions laws, regulations or rules have been proposed or are in various stages of review and/or challenge. It cannot be determined at this time what effect these various climate change and GHG emissions-related developments 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.

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 (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.

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 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 that the likelihood of an unfavorable outcome having a material impact is neither reasonably possible nor probable of occurring

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 activism.

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, natural gas and LNG;
- 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, management believes that the likelihood of an unfavorable outcome in any pending legal or regulatory proceeding having a material impact, individually or in the aggregate, is neither reasonably possible nor probable of occurring.

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 20, 2026, 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 138. On February 20, 2026, the last reported sale price of Kosmos’ common stock, as reported on the NYSE, was $2.16 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 and the Facility, unless we meet certain conditions, financial and otherwise.

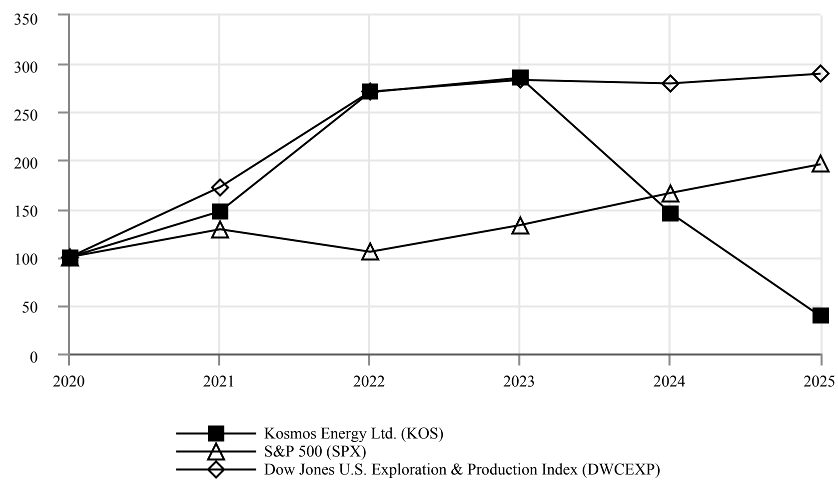
Issuer Purchases of Equity Securities

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, 2025, 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,					
	2020	**2021**	**2022**	**2023**	**2024**	**2025**
Kosmos Energy Ltd. (KOS)	$ 100.00	$ 147.23	$ 270.64	$ 285.53	$ 145.53	$ 38.61
S&P 500 (SPX)	100.00	128.68	105.36	133.03	166.28	195.98
Dow Jones U.S. Exploration & Production Index (DWCEXP)	100.00	172.35	271.20	283.34	279.67	289.76

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, 2025.

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 Energy is a leading deepwater exploration and production company focused on meeting the world's growing demand for energy. We have diversified oil and gas production from assets offshore Ghana, Equatorial Guinea, Mauritania, Senegal, and the Gulf of America. Additionally, in the proven basins where we operate we are advancing high-quality development opportunities, which have come from our exploration success.

Recent Developments

Corporate

On September 24, 2025, the Company entered into a senior secured term loan credit agreement secured by first priority liens on all of the Company's Gulf of America assets (as defined in the Credit Agreement). The GoA Term Loan Facility is a four-year term loan structured into two tranches, with the first tranche a principal amount of $150.0 million, which was funded in October 2025, and a second tranche of an additional $100.0 million, which was funded in January 2026. The net proceeds were used, together with cash on hand, to fund the redemption of the 7.125% Senior Notes due 2026 totaling $250.0 million in aggregate. The GoA Term Loan Facility is now fully drawn and matures in 2029, with principal payments beginning June 30, 2026.

On January 16, 2026, the Company announced the pricing of $350.0 million aggregate principal amount of 11.250% senior secured bonds due 2031 in the Nordic market (the "GTA Nordic bonds"). The GTA Nordic bonds are fully and unconditionally guaranteed by the Company, as well as the Company's wholly-owned subsidiaries that own the Mauritania and Senegal assets. In February 2026, Kosmos used a portion of the net proceeds from the Nordic bond offering to fund the repurchase of an aggregate principal amount of $182.5 million of its 7.750% Senior Notes due 2027 and to make a voluntary early principal repayment of $100.0 million on outstanding borrowings under the Facility, with the remaining proceeds to be used for future retirements of the 7.750% Senior Notes due 2027.

In July 2025, new U.S. tax legislation was signed into law in the United States known as the "One Big Beautiful Bill Act" or "OBBBA". The legislation includes a broad range of U.S. corporate tax reform provisions affecting businesses across numerous industries. The necessary adjustments have been reflected for the year ended December 31, 2025. Based on our evaluation, we have determined that the impact of OBBBA is not material to the Company's financial position or results.

Ghana

During the year ended December 31, 2025, Ghana production averaged approximately 93,100 Boepd gross (31,100 Boepd net).

The partnership completed a new 4D seismic survey on the Jubilee and TEN Fields during the first quarter of 2025 and an Ocean Bottom Node survey was completed in the fourth quarter of 2025. In the second quarter of 2025, we commenced the next development drilling campaign in the Jubilee Field. The Jubilee drilling progressed during the year bringing one producer well successfully online in July 2025. After undergoing scheduled maintenance, the rig returned to the Jubilee Field to drill an additional producer well, which was successfully completed and brought online in January 2026. The development drilling campaign will continue in 2026 by drilling four planned producer wells and an additional water injector well.

In June 2025, the Jubilee and TEN partnerships entered into a Memorandum of Understanding with the Government of Ghana to extend to 2040 the WCTP and the DT licenses, which cover the Jubilee and TEN fields offshore Ghana. The Ghana partnership received Government approval in December 2025 for the license extensions. Accordingly, the WCTP and DT licenses have been extended to 2040 and starting from July 2036, Ghana National Petroleum Corporation's share in the fields will increase by an additional 10% interest and the joint venture partners' shares will decrease pro rata. As part of the extension of the Petroleum Agreements, the Jubilee plan of development is amended to include up to twenty additional wells in the fields. Additionally, in December 2025, as part of the extension of the WCTP and DT Petroleum Agreements, the Ghana partners and

Government of Ghana have approved an amended gas sales agreement at a price of $2.50 per MMBtu through the extended expiration date of 2040 for the WCTP and DT licenses.

In February 2026, the TEN partnership executed the final Sale and Purchase Agreement to acquire the TEN FPSO from MODEC, Inc. at the end of its current lease in 2027 for a gross purchase price of $205.0 million.

Gulf of America

During the year ended December 31, 2025, Gulf of America production averaged approximately 17,600 Boepd (net) (~84% oil).

On Tiberius, Kosmos (operator, 50% working interest) continues to progress the development plan with our partner Occidental Petroleum Corporation ("Oxy") (50% working interest). A production handling agreement for the Oxy-operated Lucius platform was signed in the third quarter of 2025. A final investment decision and farm down to reduce Kosmos' working interest is expected in 2026.

In January 2026, Kosmos was awarded two lease blocks in the Gulf of America Big Beautiful Gulf Lease Sale 1 ("BBG1").

At Winterfell, in October 2024, shortly after startup of the Winterfell-3 well, production at the field was curtailed due to sand production from the Winterfell-3. Production from the first two wells was restored in December 2024. Remediation work on Winterfell-3 was performed in the first quarter of 2025, however, it was unsuccessful. Winterfell-3 was temporarily plugged and abandoned during the first quarter of 2025 while the partnership evaluated options to restore production from the Winterfell-3 fault block. During the second quarter of 2025, the partnership drilled the Winterfell-4 well to test a separate fault block and define the eastern extent of the Winterfell reservoir area. The Winterfell-4 well was abandoned in September 2025 by the operator due to challenges during completion operations arising from the collapse of the production casing. The partnership will continue to review alternative options to access those resources with near-term activity in 2026 focused on restoring production from the Winterfell-3 fault block.

In February 2026, Kosmos entered into a strategic alliance with Shell, exchanging interests in five exploration blocks in the Norphlet trend. Shell and Kosmos now have alignment over ten blocks in the Gulf of America to explore multiple prospects, including Trailblazer. Drilling of Trailblazer is planned for 2027 with Kosmos designated as development operator.

Equatorial Guinea

On February 24, 2026, we entered into a Share Sale and Purchase Agreement with a subsidiary of Panoro Energy ASA for the sale of all of our participating interest in the Ceiba Field and Okume Complex production assets located in Block G offshore Equatorial Guinea for upfront cash consideration of $180 million, subject to certain adjustments, and future contingent consideration of up to $39.5 million, comprising $12.5 million linked to production performance at the Ceiba field and $9 million payable in each of 2027, 2028 and 2029, which are subject to certain oil price and production thresholds. The transaction has received approval from the Government of Equatorial Guinea and completion only remains subject to CEMAC customary approval. While we expect to close the transaction around the middle of 2026, there can be no assurances that closing will ultimately occur or that it may not be delayed. As such, the Company has elected to report on the business throughout this Form 10-K on the basis that the transaction has not yet closed and that the Company continues to own all of the participating interest in the Ceiba Field and Okume Complex production assets located in Block G offshore Equatorial Guinea. All such references to the Company's future plans and expectations for the Equatorial Guinea business unit should therefore be read in light of the ongoing transaction.

Production in Equatorial Guinea averaged approximately 20,400 Bopd gross (7,200 Bopd net) for the year ended December 31, 2025, impacted by multiple flow pump (MPP) mechanical failures at Ceiba during the second quarter of 2025. One pump is currently back online with another pump expected to be online in the first quarter of 2026.

In October 2025, we received approval from the Ministry of Hydrocarbons and Mining Development for a twelve month extension to December 2026 for the current exploration phase of Block EG-24.

In October 2025, we submitted a formal notice to the Ministry of Hydrocarbons and Mining Development that we are electing to exit Block S offshore Equatorial Guinea.

In February 2026, we notified our partners that we are withdrawing from Block EG-01.

In the fourth quarter of 2024, the corporate tax rate in Equatorial Guinea was reduced from 35% to 25%, with an effective date of January 1, 2025.

Mauritania and Senegal

Greater Tortue Ahmeyim Project

Production in Mauritania and Senegal averaged approximately 35,000 Boepd gross (8,500 Boepd net) for the full year ended December 31, 2025, as production from the Greater Tortue Ahmeyim (GTA) liquefied natural gas (LNG) project ramped up. The GTA LNG project achieved first gas production from the subsea system to the FPSO on December 31, 2024. First LNG was achieved in February 2025 and the first gross LNG cargo was successfully exported in April 2025. Eighteen and a half gross LNG cargos and one condensate cargo were lifted in 2025. The Gimi FLNG vessel Commercial Operations Date was achieved in the second quarter of 2025 with successful ramp-up to the daily contracted sales volume level under the Tortue Phase 1 SPA, equivalent to approximately 2.45 million tonnes per annum. Production averaged approximately 58,200 Boepd gross (14,200 Boepd net) for the three months ended December 31, 2025. Additionally, the Gimi FLNG vessel operated at nameplate capacity in December 2025, reaching a peak production rate of approximately 3.0 million tonnes per annum.

Yakaar and Teranga Discoveries

On Yakaar-Teranga, we are working with PETROSEN to withdraw from the block given we have not been able to attract a suitable partner and agree a commercially attractive development concept with the government of Senegal. Accordingly, during the year ended December 31, 2025, we wrote off $143.7 million of unproved property costs associated with the Yakaar and Teranga discoveries, which were largely incurred before 2020.

Sao Tome and Principe

In May 2025, we received approval for a twelve month extension to May 2026 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, Equatorial Guinea, Mauritania, Senegal, the Gulf of America. Certain operating results and statistics for the years ended December 31, 2025, 2024 and 2023 are included in the following tables. For a discussion of the year ended December 31, 2024 compared to the year ended December 31, 2023, 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, 2024.

	Years ended December 31,		
	2025	2024	2023
	(In thousands, except per volume data)		
Sales volumes:			
Oil (MBbl)	16,452	20,472	20,385
Gas (MMcf)	32,280	16,180	13,737
NGL (MBbl)	582	338	382
Total (MBoe)	22,414	23,507	23,057
Total (Boepd)	61,408	64,226	63,168
Revenues:			
Oil sales	$ 1,100,483	$ 1,611,169	$ 1,658,421
Gas sales	170,548	57,243	35,307
NGL sales	17,321	6,946	7,880
Total revenues	$ 1,288,352	$ 1,675,358	$ 1,701,608
Average oil sales price per Bbl	$ 66.89	$ 78.70	$ 81.35
Average gas sales price per Mcf	5.28	3.54	2.57
Average NGL sales price per Bbl	29.76	20.55	20.61
Average total sales price per Boe	57.48	71.27	73.80
Costs:			
Oil and gas production, excluding workovers	$ 686,039	$ 490,860	$ 367,375
Oil and gas production, workovers	22,863	39,654	22,722
Total oil and gas production costs	$ 708,902 (1)	$ 530,514 (1)	$ 390,097
Depletion, depreciation and amortization	$ 556,774	$ 456,774	$ 444,927
Average cost per Boe:			
Oil and gas production, excluding workovers	$ 30.61	$ 20.88	$ 15.93
Oil and gas production, workovers	1.02	1.69	0.99
Total oil and gas production costs	31.63 (1)	22.57 (1)	16.92
Depletion, depreciation and amortization	24.84	19.43	19.30
Total oil and gas production costs, depletion, depreciation and amortization	$ 56.47	$ 42.00	$ 36.22

(1) Substantially all NGLs and natural gas sales in Ghana and the Gulf of America are associated production from our oil wells and, therefore, production costs metrics are presented under a common unit of measure. In Mauritania and Senegal, all condensate sales and LNG sales are associated production from our gas wells. Includes $93.4 million of pre-production operating costs for the year ended December 31, 2024 incurred before production commenced at the Greater Tortue Ahmeyim Phase 1 project in Mauritania and Senegal. Oil and gas production costs related to the LNG production at the GTA Phase 1 project were $237.6 million for the year ended December 31, 2025. First LNG was achieved in February 2025 and the first LNG cargo was successfully completed in April 2025. Production costs per Bcf in Mauritania and Senegal was $14.68 for the year ended December 31, 2025. Mauritania and Senegal LNG sales are presented as gas sales in the table.

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, 2025 vs. 2024

	Years Ended December 31,		Increase
	2025	2024	(Decrease)
		(In thousands)	
Revenues and other income:			
Oil and gas revenue	$ 1,288,352	$ 1,675,358	$ (387,006)
Gain on sale of assets	2,200	—	2,200
Other income, net	1,098	204	894
Total revenues and other income	1,291,650	1,675,562	(383,912)
Costs and expenses:			
Oil and gas production	708,902	530,514	178,388
Exploration expenses	223,616	119,907	103,709
General and administrative	76,120	100,155	(24,035)
Depletion, depreciation and amortization	556,774	456,774	100,000
Impairment of long-lived assets	177,563	—	177,563
Interest and other financing costs, net	223,430	88,598	134,832
Derivatives, net	(53,665)	12,099	(65,764)
Other expenses, net	13,491	17,703	(4,212)
Total costs and expenses	1,926,231	1,325,750	600,481
Income (loss) before income taxes	(634,581)	349,812	(984,393)
Income tax expense	65,205	159,961	(94,756)
Net income (loss)	$ (699,786)	$ 189,851	$ (889,637)

Oil and gas revenue. Oil and gas revenue decreased by $387.0 million during the year ended December 31, 2025 as compared to the year ended December 31, 2024 primarily as a result of lower average realized oil and gas prices and lower production resulting in lower sales volume at Jubilee and Equatorial Guinea partially offset by increased sales volumes in Mauritania and Senegal with LNG and condensate cargo sales beginning in 2025. We sold 22,414 MBoe at an average realized price per barrel of oil equivalent of $57.48 in 2025 and 23,507 MBoe at an average realized price per barrel of oil equivalent of $71.27 in 2024.

Oil and gas production. Oil and gas production costs increased by $178.4 million during the year ended December 31, 2025 as compared to the year ended December 31, 2024 primarily as a result of a full year of operating costs associated with the ramp-up of LNG production at the GTA Phase 1 project in Mauritania and Senegal.

Exploration expenses. Exploration expenses increased by $103.7 million during the year ended December 31, 2025, as compared to the year ended December 31, 2024 primarily as a result of approximately $58.5 million of exploration expense related to the Winterfell-4 step out well which was plugged and abandoned during the third quarter of 2025 and approximately $143.7 million of previously capitalized costs related to the Yakaar and Teranga discoveries incurred under the Cayar Offshore Profound Block license that were written off to exploration expense for the year ended December 31, 2025 compared to approximately $28.0 million related to the S-6 "Akeng Deep" ILX prospect in Block S offshore Equatorial Guinea which encountered sub-commercial quantities of hydrocarbons and was plugged and abandoned in the fourth quarter of 2024 and approximately $37.2 million of previously capitalized costs related to the Asam discovery in Block S offshore Equatorial Guinea that were written off to exploration expense for the year ended December 31, 2024, partially offset by decreased seismic, geological and geophysical studies and related costs as part of the Company's focus on managing costs across our portfolio.

Depletion, depreciation and amortization. Depletion, depreciation and amortization increased $100.0 million during the year ended December 31, 2025, as compared to the year ended December 31, 2024 primarily as a result of the ramp-up of LNG production resulting in first LNG and condensate sales in 2025 at the GTA Phase 1 project in Mauritania and Senegal and higher depletion rates per Boe across our portfolio partially offset by lower sales volumes at Jubilee and Equatorial Guinea.

Impairment of long-lived assets. As a result of negative proved oil and gas reserves revisions in certain of our Gulf of America fields, primarily Winterfell, we recorded a proved property impairment charge of $177.6 million during the year ended December 31, 2025.

Interest and other financing costs, net. Interest and other financing costs, net increased by $134.8 million during the year ended December 31, 2025, as compared to the year ended December 31, 2024 primarily as a result of decreased capitalized interest for the year ended December 31, 2025 related to the GTA Phase 1 project post first gas production in December 2024 partially offset by a $25.2 million loss on debt modifications and extinguishments primarily related to the amendment and restatement of the Facility during the second quarter of 2024.

Income tax expense (benefit). For the years ended December 31, 2025 and 2024, our overall effective tax rates were impacted by the difference in our 21% U.S. income tax reporting rate and the 35% statutory tax rate applicable to our Ghanaian operations and the 25% statutory tax rate applicable to our Equatorial Guinean operations, jurisdictions that have a 0% statutory tax rate, or 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 deepwater 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 oil price volatility 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 2026.

As such, our 2026 capital budget is based on our exploitation plans for our producing assets in Ghana, Equatorial Guinea, Mauritania, Senegal and the Gulf of America, and our development activities in the Gulf of America and in Mauritania and Senegal.

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, natural gas, and LNG and 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.

As of December 31, 2025, borrowings under the Facility totaled approximately $1.2 billion and the undrawn availability under the facility was $150.0 million. In September 2025, during the Fall 2025 redetermination, the Company's lending syndicate approved a borrowing base at the full Facility size of $1.35 billion.

Leverage was elevated in 2025 given lower oil prices and the impact of operating costs during ramp-up of the GTA Phase 1 project combined with lower Company production. As a result, in July 2025, the Company and the Facility lenders agreed to amend the debt cover ratio required under the Facility. The amendment made this covenant less restrictive for the two scheduled financial covenant assessment dates in September 2025 and March 2026, up to a maximum of 4.0x and 4.25x respectively, and returned to the originally agreed upon ratio of 3.50x for assessment dates thereafter. In February 2026, we further amended the debt cover ratio calculation through September 2026. This most recent amendment makes the covenant less restrictive for the two scheduled financial covenant assessment dates in March 2026 and September 2026, up to a maximum of 4.5x and 4.25x respectively, and for purposes of the financial covenant assessment date in March 2026, the calculation will be made excluding the Company's Mauritania and Senegal business unit. The debt cover ratio returns to the originally agreed upon ratio of 3.5x for assessment dates thereafter. The change is intended to align the covenant calculation with recent business operations, lower potential oil prices and the impact of operating costs during ramp-up of the GTA Phase 1 project on our results of operations.

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, 2025, 2024 and 2023:

	Years Ended December 31,		
	2025	2024	2023
		(In thousands)	
Sources of cash, cash equivalents and restricted cash:			
Net cash provided by operating activities	$ 134,012	$ 678,249	$ 765,170
Net proceeds from issuance of senior notes	—	885,285	—
Borrowings under long-term debt	675,000	325,000	300,000
	809,012	1,888,534	1,065,170
Uses of cash, cash equivalents and restricted cash:			
Oil and gas assets	314,408	933,659	932,603
Notes receivable and other investing activities	86,791	32,397	62,247
Payments on long-term debt	225,000	350,000	145,000
Purchase of capped call transactions	—	49,800	—
Repurchase and redemption of senior notes	150,000	499,515	—
Dividends	—	—	166
Other financing costs	346	36,647	13,214
	776,545	1,902,018	1,153,230
Increase (decrease) in cash, cash equivalents and restricted cash	$ 32,467	$ (13,484)	$ (88,060)

Net cash provided by operating activities. Net cash provided by operating activities in 2025 was $134.0 million compared with net cash provided by operating activities of $678.2 million in 2024 and $765.2 million in 2023, respectively. The decrease in cash provided by operating activities in the year ended December 31, 2025 when compared to the same period in 2024 is primarily a result of lower average realized oil and gas prices, lower sales volumes in Ghana and Equatorial Guinea, higher oil and gas production costs related to the ramp-up of LNG production at the GTA Phase 1, partially offset by increased sales volumes in Mauritania and Senegal with LNG and condensate cargo sales beginning in 2025 and lower workover expense in Equatorial Guinea. The decrease in cash provided by operating activities in the year ended December 31, 2024 when compared to the same period in 2023 is primarily a result of increased oil and gas production costs for the year ended December 31, 2024 as a result of pre-production operating costs associated with the GTA Phase 1 project, planned workovers in the Gulf of America business unit, and increased production costs in Equatorial Guinea, together with lower average realized oil prices, offset by changes in working capital.

The following table presents our liquidity and financial position as of December 31, 2025 and 2024:

	Years Ended December 31, 2025	2024
	(In thousands)	
Outstanding debt principal balances:		
Facility(2)	$ 1,200,000	$ 900,000
7.125% Senior Notes(1)	100,000	250,000
7.750% Senior Notes(2)	350,000	350,000
7.500% Senior Notes	400,274	400,274
8.750% Senior Notes	500,000	500,000
3.125% Convertible Senior Notes	400,000	400,000
GoA Term Loan Facility(1)	150,000	—
Total long-term debt	$ 3,100,274	$ 2,800,274
Cash and cash equivalents	91,518	84,972
Total restricted cash(3)	26,226	305
Net debt	$ 2,982,530	$ 2,714,997
Availability under the Facility(2)	$ 150,000	$ 450,000
Availability under the GoA Term Loan Facility(1)	$ 100,000	$ —
Available borrowings plus cash and cash equivalents	$ 341,518	$ 534,972

(1) As of December 31, 2025, the undrawn availability under the GoA Term Loan Facility was $100 million, subject to certain conditions on borrowing. In January 2026, we received net proceeds of $98.5 million from funding the second tranche after deducting fees and other expenses. The net proceeds were used, together with cash on hand, to fund the redemption of the remaining $100.0 million of the 7.125% Senior Notes due 2026.

(2) As of December 31, 2025, the undrawn availability under the Facility was $150.0 million, subject to certain conditions on borrowing. In January 2026, the Company issued $350 million of 11.250% Senior Secured Bonds due in 2031 in the Nordic market. In February 2026, Kosmos used a portion of the net proceeds from the Nordic bond offering to fund the repurchase of an aggregate principal amount of $182.5 million of the 7.750% Senior Notes due 2027 and to make a voluntary early principal repayment of $100.0 million on outstanding borrowings under the Facility.

(3) When our debt cover 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 7.750% Senior Notes, the 7.500% Senior Notes, the 8.750% Senior Notes and the 3.125% Convertible Senior Notes or the Facility, whichever is greater. As of December 31, 2024, our debt cover ratio was 2.54x. During the first quarter of 2025, the Facility lenders waived the requirement to maintain a restricted cash balance through 2025. As of December 31, 2025, our debt cover ratio was 5.49x. Our next financial covenant assessment date is March 31, 2026, after which date we will be required to restrict approximately $50.0 million in cash as required under the terms of the Facility unless otherwise waived by the lenders

Capital Expenditures and Investments

We expect to incur capital costs as we:

- drill additional infill wells in Ghana and the Gulf of America;
- advance development efforts in the Gulf of America and in Mauritania and Senegal; and
- execute facilities integrity activities in 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 and divestment opportunities, 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.

2026 *Capital Program*

We estimate we will spend approximately $350 million of capital for the year ending December 31, 2026, excluding any acquisitions or divestiture of oil and gas properties during the year. This capital expenditure budget consists of:

- Approximately $275 million related to maintenance activities across our Ghana and Gulf of America assets, including infill development drilling and TEN FPSO purchase payments;
- Approximately $60 million related to progressing our development programs in the Gulf of America and in Mauritania and Senegal; and
- Approximately $15 million related to facilities integrity activities in Equatorial Guinea.

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, natural gas, and LNG and the prices we receive from the sale of oil, natural gas and LNG, and our ability to effectively hedge future production volumes, the success of our multi-faceted infrastructure-led exploration, appraisal, and development 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 September 2025, during the Fall 2025 redetermination, the Company's lending syndicate approved a borrowing base at the full Facility size of $1.35 billion. As of December 31, 2025, borrowings under the Facility totaled $1.2 billion and the undrawn availability under the facility was $150.0 million. In February 2026, the Company used a portion of the net proceeds from the Nordic bond offering to make a voluntary early principal repayment of $100.0 million on outstanding 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 April 1, 2027, outstanding borrowings will be constrained by an amortization schedule. The Facility has a final maturity date of December 31, 2029. As of December 31, 2025, 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 amended, as of September 30, 2025 (the most recent assessment date). The Facility 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 are unable to perform on their commitments, our liquidity could be impacted. We actively monitor all of the financial institutions participating in our Facility. 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 refer to as the "Senior Notes." Our 7.750% Senior Notes have an outstanding balance of $350.0 million as of December 31, 2025 and mature on May 1, 2027. In February 2026, we used a portion of the net proceeds from the Nordic bond offering to fund the repurchase of an aggregate principal amount of $182.5 million of the 7.750% Senior Notes. Interest is payable on the 7.750% Senior Notes each May 1 and November 1. Our 7.500% Senior Notes have an outstanding balance of approximately $400.3 million on December 31, 2025 and mature on March 1, 2028. Interest is payable on the 7.500% Senior Notes each March 1 and September 1. Our 8.750% Senior Notes have an outstanding balance of $500.0 million on December 31, 2025 and mature on October 1, 2031. Interest is payable on the 8.750% Senior Notes each April 1 and October 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 the 3.125% Convertible 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 Senior Notes are jointly and severally guaranteed on a senior, unsecured basis by certain subsidiaries owning the Company's Gulf of America assets, and on a subordinated, unsecured basis by entities that borrow under, or guarantee, our Facility.

3.125% Convertible Senior Notes due 2030

We have one series of senior convertible notes outstanding. Our 3.125% Convertible Senior Notes mature on March 15, 2030, unless earlier converted, redeemed or repurchased. Interest is payable in arrears each March 15 and September 15, commencing September 15, 2024.

The 3.125% Convertible 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 the 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, to the extent of the value of the assets securing such indebtedness). The 3.125% Convertible Senior Notes are guaranteed on a senior, unsecured basis by certain of our existing subsidiaries that guarantee on a senior basis the Senior Notes, and, in certain circumstances, certain of our existing future subsidiaries. The 3.125% Convertible Senior Notes are guaranteed on a subordinated, unsecured basis by certain of our existing subsidiaries that borrow under or guarantee the Facility and guarantee on a subordinated basis the Senior Notes, and, in certain circumstances, certain of our existing or future subsidiaries.

The 3.125% Convertible Senior Notes indenture contains customary terms and covenants.

In connection with the issuance of the 3.125% Convertible Senior Notes, the Company entered into capped call transactions (the "Capped Call Transactions"). The Capped Call Transactions are generally expected to reduce potential dilution to holders of our common stock upon any conversion of the 3.125% Convertible Senior Notes and/or offset any cash payments that we are required to make in excess of the principal amount of any 3.125% Convertible Senior Notes that are converted, as the case may be, with such reduction and/or offset subject to a cap.

GoA Term Loan Facility

On September 24, 2025, the Company entered into a senior secured term loan credit agreement secured by first priority liens on all the Company's Gulf of America assets (as defined in the GoA Term Loan credit agreement). The GoA Term Loan Facility is a four-year term loan structured in two tranches, with the first tranche an aggregate principal amount of $150.0 million, which was funded in October 2025, and a second tranche of an additional $100.0 million, which was funded in January 2026. The net proceeds were used, together with cash on hand, to fund the redemption of the $250.0 million in aggregate, of the 7.125% Senior Notes due 2026.

Interest on outstanding loans under the GoA Term Loan Facility is payable quarterly in arrears at a rate per annum equal to 3.75% plus the term SOFR reference rate administered by CME Group Benchmark Administration Limited for the relevant period published. The GoA Term Loan Facility is now fully drawn and matures in 2029, with principal payments beginning June 30, 2026.

The GoA Term Loan Facility contains customary affirmative and negative covenants, including covenants that affect our ability to incur additional indebtedness, create liens, merge, dispose of assets, and make distributions, dividends, investments or capital expenditures, among other things. The GoA Term Loan Facility requires the Company to maintain certain financial covenants including:

- the GoA field life coverage ratio (as defined in the glossary), not less than 1.50x; and
- the GoA net leverage ratio (as defined in the glossary), not more than 3.50x

The GoA Term Loan Facility includes certain representations and warranties, indemnities and events of default that, subject to materiality thresholds and grace periods, arise as a result of a payment of default, failure to comply with covenants, material inaccuracy of representation or warranty, and certain bankruptcy or insolvency proceedings. If there is an event of default, all or any portion of the outstanding indebtedness may be immediately due and payable and other rights may be exercised including against the collateral.

GTA Nordic Bonds

In January 2026, we issued one series of senior secured GTA Nordic bonds totaling $350.0 million. Our 11.250% senior secured GTA Nordic bonds mature in January 2031, unless earlier redeemed or repurchased. Interest is payable semi-annually in arrears each July 29 and January 29, commencing July 29, 2026.

The GTA Nordic bonds were issued by Kosmos Energy GTA Holdings, a wholly-owned subsidiary of Kosmos Energy Ltd., and are fully and unconditionally guaranteed by the Company, as well as the Company's wholly-owned subsidiaries, Kosmos Energy Tortue Finance, Kosmos Energy Senegal, Kosmos Energy Investments Senegal Limited and Kosmos Energy Mauritania. The GTA Nordic bonds are also guaranteed on an unsecured basis by certain of the Company's subsidiaries that also guarantee the Company's existing senior unsecured notes.

Contractual Obligations

The following table presents maturities by expected debt maturity dates, the weighted-average interest rates expected to be paid on the Facility 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,
	2026	2027	2028	2029	2030	Thereafter	Total	2025
	(In thousands, except percentages)							
Fixed rate debt:								
7.125% Senior Notes(5)	$100,000	$ —	$ —	$ —	$ —	$ —	$ 100,000	$ 99,303
7.750% Senior Notes(6)	—	350,000	—	—	—	—	350,000	321,394
7.500% Senior Notes	—	—	400,274	—	—	—	400,274	270,125
8.750% Senior Notes	—	—	—	—	—	500,000	500,000	283,575
3.125% Convertible Senior Notes	—	—	—	—	400,000	—	400,000	172,704
Variable rate debt:								
Weighted average interest rate	8.15 %	8.24 %	8.91 %	9.34 %	— %	— %		
Facility(1)(6)	$ —	$320,449	$385,508	$494,043	$ —	$ —	$1,200,000	1,200,000
GoA Term Loan Facility(5)	32,143	42,857	42,857	32,143	—	—	150,000	150,000
Total principal debt repayments	$132,143	$713,306	$828,639	$526,186	$400,000	$500,000	$3,100,274	
Interest & commitment fees on long-term debt	229,905	203,158	140,351	87,655	50,000	43,750	754,819	
Operating leases(2)	3,923	3,956	3,744	3,176	—	—	14,799	
Purchase obligations(3)	18,702	—	—	—	—	—	18,702	
Decommissioning trust funds(4)	11,598	8,284	8,284	8,284	8,284	77,865	122,599	
Firm transportation commitments	4,180	2,363	—	—	—	—	6,543	

(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, 2025. 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.

(4) In April 2024, a decommissioning trust agreement with the Jubilee unit partners to cash fund future retirement costs associated with the Jubilee Field was finalized. The operator currently estimates the total remaining commitment to be approximately $122.6 million as of December 31, 2025, net to Kosmos, which will be funded annually by Kosmos over an estimated fifteen year period based on the expiration date of the WCTP and DT Petroleum Agreements, which has now been extended to 2040. It is possible that our funding requirements could change based on future changes in the decommissioning plan or estimates.

(5) In January 2026, we used net proceeds of $98.5 million from the funding of the second tranche of the GoA Term Loan Facility, together with cash on hand, to fund the redemption of the remaining $100.0 million of the 7.125% Senior Notes due 2026.

(6) In January 2026, the Company issued $350.0 million of 11.250% Senior Secured Bonds due 2031 in the Nordic market. In February 2026, Kosmos used a portion of the net proceeds from the Nordic bond offering to fund the repurchase of an aggregate principal amount of $182.5 million of the 7.750% Senior Notes due 2027 and to make a voluntary early principal repayment of $100.0 million on outstanding borrowings under the Facility.

As of December 31, 2025, we have a commitment to drill one development well in Equatorial Guinea. As part of the license extensions of WCTP and DT Petroleum Agreements in Ghana, we have a commitment to drill a minimum of ten development wells under the amended Jubilee plan of development.

Once the Tortue Phase 1 SPA Commercial Operations Date was achieved in February 2026, we have a commitment to our buyer under the Tortue Phase 1 SPA, BP Gas Marketing Limited, to deliver our proportionate share of a minimum annual contract quantity of LNG of 127,951,000 MMBtu, which is equivalent to approximately 2.45 million tonnes per annum, subject to certain downward adjustments by the sellers. Under certain circumstances, in the event the annual quantities provided are lower than the minimum annual contract quantity, Kosmos may be obligated to credit or pay a portion of the Contract Price to BP Gas Marketing Limited for the shortfall volumes.

In February 2026, the TEN partnership executed the final Sale and Purchase Agreement to acquire the TEN FPSO from MODEC, Inc. at the end of its current lease in 2027 for a gross purchase price of $205.0 million. We have a commitment to Tullow for our proportionate share of the gross purchase price.

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, 2025 and 2024, 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 separated from the host contract for accounting purposes. The host contract is the receivable from 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, 2025 and 2024, 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 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 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. Proved reserve quantities and future cash flows are estimated by independent petroleum engineering 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 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, 2025:

	Derivative Contracts Assets (Liabilities)		
	Commodities	Interest Rates	Total
		(In thousands)	
Fair value of contracts outstanding as of December 31, 2024	$ 9,468	$ 2,202	$ 11,670
Changes in contract fair value	44,171	837	45,008
Contract maturities	(3,142)	(3,039)	(6,181)
Fair value of contracts outstanding as of December 31, 2025	$ 50,497	$ —	$ 50,497

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 2025 ranged between $60.20 and $83.06 per Bbl for Dated Brent, with Heavy Louisiana Sweet experiencing similar volatility during 2025.

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, 2025. 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)	Swap	Sold Put	Floor	Ceiling	Asset (Liability) Fair Value at December 31, 2025(1)
2026:									
Jan - Jun	Two-way collars	Dated Brent	1,000	$ 1.55	$ —	$ —	$ 60.00	$ 74.75	$ 1,002
Jan - Dec	Three-way collars	Dated Brent	2,000	—	—	50.00	60.00	75.51	4,084
Jan - Jun	Swaps(1)	Dated Brent	1,000	—	72.90	—	—	80.00	12,006
Jan - Dec	Swaps(1)	Dated Brent	1,000	—	72.46	—	—	80.00	11,352
Jan - Dec	Swaps(1)	Dated Brent	2,000	—	69.70	55.00	—	—	13,347
Jan - Dec	Swaps(1)	NYMEX WTI	1,500	—	64.83	50.00	—	—	8,706

(1) Includes call option contracts sold to counterparties to enhance Swaps.

In January 2026, we entered into Dated Brent three-way collar contracts for 2.0 MMBbl from January 2027 through December 2027 with a weighted average sold put price of $47.50 per barrel, a floor price of $60.00 per barrel and a ceiling price of $75.00 per barrel.

At December 31, 2025, our open commodity derivative instruments were in a net asset position of $50.5 million. As of December 31, 2025, a hypothetical 10% price increase in the commodity futures price curves would decrease future pre-tax earnings by approximately $36.7 million. Similarly, a hypothetical 10% price decrease would increase future pre-tax earnings by approximately $36.2 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 and GoA Term Loan Facility as of December 31, 2025 totaled $1.35 billion. The weighted average interest rate on this indebtedness was approximately 7.7%, and is 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 $4.9 million of interest expense per year on the Facility and GoA Term Loan Facility. The commitment fees on the undrawn availability under the Facility 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 payments associated with the Tortue FPSO 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, 2025 and 2024, the related consolidated statements of operations, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2025, 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, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated March 2, 2026 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 Matter

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

	Depletion of Oil and gas properties, net and impairment of long-lived assets
Description of the Matter	At December 31, 2025, the net book value of the Company's oil and gas properties, net was $3.7 billion, and depletion expense and impairment of long-lived assets were $517.1 million and $177.6 million, respectively for the year then ended. As described in Note 2, the Company follows the successful efforts method of accounting for its oil and gas properties. Proved properties and support equipment and facilities are depleted using the unit-of-production method based on estimated proved oil and gas reserves. The Company reviews their long-lived assets for impairment when changes in circumstances indicate that the carrying amount of an asset may not be recoverable. 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. For long-lived assets whereby the carrying value exceeds the estimated future undiscounted cash flows, the carrying amount is reduced to 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, among others. Proved reserve quantities and future cash flows are estimated by independent petroleum engineering consultants and prepared in accordance with guidelines established by the SEC and the FASB. The accuracy of these reserve estimates is a function of (i) the engineering and geological interpretation of available data, (ii) estimates of the amount and timing of future operating cost, production taxes, development cost and workover cost, (iii) the accuracy of various mandated economic assumptions, and (iv) the judgments of the persons preparing the estimates. The Company's depletion expense and impairment of long-lived asset calculations include (i) subjective judgments by the Company's independent petroleum engineering consultants when developing the estimates of proved oil and gas reserve volumes, and(ii) a high degree of auditor judgment in performing procedures and evaluating audit evidence related to the methods and assumptions used by the Company's independent petroleum engineering consultants in developing the estimates of proved oil and gas reserve volumes.
How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design and tested the operating effectiveness of internal controls that address the risk of material misstatement relating to depletion expense and impairment of long-lived assets. This included internal controls over the completeness and accuracy of the historical production volumes provided to the independent petroleum engineering consultants for use in estimating the proved oil and gas reserves. Our audit procedures included, among others, evaluating the methods and assumptions used by the independent petroleum engineering consultants, testing the completeness and accuracy of the data related to historical production volumes, and evaluating the professional qualifications and objectivity of the independent petroleum engineering consultants used to prepare the estimate of proved oil and gas reserves.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2004.
Dallas, Texas
March 2, 2026

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, 2025, 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, 2025, 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, 2025 and 2024, the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2025, and the related notes and financial statement schedules listed in the Index at Item 15(a) and our report dated March 2, 2026 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
March 2, 2026

KOSMOS ENERGY LTD.

CONSOLIDATED BALANCE SHEETS

(In thousands, except share data)

	December 31,	
	2025	**2024**
Assets		
Current assets:		
Cash and cash equivalents	$ 91,518	$ 84,972
Receivables	103,472	164,959
Inventories	172,640	170,871
Prepaid expenses and other	12,428	16,414
Derivatives	47,816	8,916
Total current assets	427,874	446,132
Property and equipment, net	3,733,784	4,444,221
Other assets:		
Restricted cash	26,226	305
Long-term receivables	458,793	385,463
Deferred tax assets	3,946	4,717
Derivatives	2,681	512
Other	43,322	27,638
Total assets	$ 4,696,626	$ 5,308,988
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable	$ 202,555	$ 349,994
Accrued liabilities	237,609	244,954
Current maturities of long-term debt	132,143	—
Total current liabilities	572,307	594,948
Long-term liabilities:		
Long-term debt, net	2,920,616	2,744,712
Asset retirement obligations	327,016	406,886
Deferred tax liabilities	305,924	313,433
Other long-term liabilities	42,173	48,585
Total long-term liabilities	3,595,729	3,513,616
Stockholders' equity:		
Preference shares, $0.01 par value; 200,000,000 authorized shares; zero issued at December 31, 2025 and December 31, 2024	—	—
Common stock, $0.01 par value; 2,000,000,000 authorized shares; 522,590,223 and 516,158,749 issued at December 31, 2025 and December 31, 2024, respectively	5,226	5,162
Additional paid-in capital	2,542,627	2,514,739
Accumulated deficit	(1,782,256)	(1,082,470)
Treasury stock, at cost, 44,263,269 shares at December 31, 2025 and December 31, 2024, respectively	(237,007)	(237,007)
Total stockholders' equity	528,590	1,200,424
Total liabilities and stockholders' equity	$ 4,696,626	$ 5,308,988

See accompanying notes.

KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)

	Years Ended December 31,		
	2025	**2024**	**2023**
Revenues and other income:			
Oil and gas revenue	$ 1,288,352	$ 1,675,358	$ 1,701,608
Gain on sale of assets	2,200	—	—
Other income, net	1,098	204	(73)
Total revenues and other income	1,291,650	1,675,562	1,701,535
Costs and expenses:			
Oil and gas production	708,902	530,514	390,097
Exploration expenses	223,616	119,907	42,278
General and administrative	76,120	100,155	99,532
Depletion, depreciation and amortization	556,774	456,774	444,927
Impairment of long-lived assets	177,563	—	222,278
Interest and other financing costs, net	223,430	88,598	95,904
Derivatives, net	(53,665)	12,099	11,128
Other expenses, net	13,491	17,703	23,656
Total costs and expenses	1,926,231	1,325,750	1,329,800
Income (loss) before income taxes	(634,581)	349,812	371,735
Income tax expense	65,205	159,961	158,215
Net income (loss)	$ (699,786)	$ 189,851	$ 213,520
Net income (loss) per share:			
Basic	$ (1.47)	$ 0.40	$ 0.46
Diluted	$ (1.47)	$ 0.40	$ 0.44
Weighted average number of shares used to compute net income (loss) per share:			
Basic	477,591	470,844	459,641
Diluted	477,591	476,691	481,070

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, 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 and cash settlements 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
Capped call transactions	—	—	(49,800)	—	—	(49,800)
Equity-based compensation	—	—	37,957	—	—	37,957
Restricted stock units	11,766	118	(118)	—	—	—
Tax withholdings and cash settlements on restricted stock units	—	—	(9,921)	—	—	(9,921)
Net income	—	—	—	189,851	—	189,851
Balance as of December 31, 2024	516,159	5,162	2,514,739	(1,082,470)	(237,007)	1,200,424
Equity-based compensation	—	—	27,953	—	—	27,953
Restricted stock units	6,431	64	(64)	—	—	—
Tax withholdings and cash settlements on restricted stock units	—	—	(1)	—	—	(1)
Net loss	—	—	—	(699,786)	—	(699,786)
Balance as of December 31, 2025	522,590	$ 5,226	$ 2,542,627	$ (1,782,256)	$ (237,007)	$ 528,590

See accompanying notes.

KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31,		
	2025	2024	2023
Operating activities			
Net income (loss)	$ (699,786)	$ 189,851	$ 213,520
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization (including deferred financing costs)	564,660	465,483	454,848
Deferred income taxes	(6,738)	(52,174)	(107,560)
Unsuccessful well costs and leasehold impairments	202,492	74,489	2,208
Impairment of long-lived assets	177,563	—	222,278
Change in fair value of derivatives	(45,008)	14,747	28,349
Cash settlements on derivatives, net (including $10.4 million and $(12.5) million and $(16.4) million on commodity hedges during 2025, 2024, and 2023)	6,181	(19,652)	(32,426)
Equity-based compensation	27,953	37,951	42,693
Gain on sale of assets	(2,200)	—	—
Debt modifications and extinguishments	195	25,173	1,503
Other	(21,881)	(13,735)	5,709
Changes in assets and liabilities:			
(Increase) decrease in receivables	92,173	(63,331)	(16,223)
(Increase) decrease in inventories and prepaid expenses	(6,590)	4,988	(45,667)
Increase (decrease) in accounts payable and accrued liabilities	(155,002)	14,459	(4,062)
Net cash provided by operating activities	134,012	678,249	765,170
Investing activities			
Oil and gas assets	(314,408)	(933,659)	(932,603)
Notes receivable and other investing activities	(86,791)	(32,397)	(62,247)
Net cash used in investing activities	(401,199)	(966,056)	(994,850)
Financing activities			
Borrowings under long-term debt	675,000	325,000	300,000
Payments on long-term debt	(225,000)	(350,000)	(145,000)
Net proceeds from issuance of senior notes	—	885,285	—
Repurchase and redemption of senior notes	(150,000)	(499,515)	—
Purchase of capped call transactions	—	(49,800)	—
Dividends	—	—	(166)
Other financing costs	(346)	(36,647)	(13,214)
Net cash provided by financing activities	299,654	274,323	141,620
Net increase (decrease) in cash, cash equivalents and restricted cash	32,467	(13,484)	(88,060)
Cash, cash equivalents and restricted cash at beginning of period	85,277	98,761	186,821
Cash, cash equivalents and restricted cash at end of period	$ 117,744	$ 85,277	$ 98,761

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 Energy is a leading deepwater exploration and production company focused on meeting the world's growing demand for energy. We have diversified oil and gas production from assets offshore Ghana, Equatorial Guinea, Mauritania, Senegal, and the Gulf of America. Additionally, in the proven basins where we operate we are advancing high-quality development opportunities, which have come from our exploration success. 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 Gulf of America.

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,		
	2025	2024	2023
		(In thousands)	
Cash and cash equivalents	$ 91,518	$ 84,972	$ 95,345
Restricted cash - long-term	26,226	305	3,416
Total cash, cash equivalents and restricted cash shown in the consolidated statements of cash flows	$ 117,744	$ 85,277	$ 98,761

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. Long-term restricted cash primarily represents cash and cash equivalents collateralized, in accounts held by us, as required to support existing performance obligations in the GoA. When our debt cover 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 7.750% Senior Notes, the 7.500% Senior Notes, the 8.750% Senior Notes and the 3.125% Convertible Senior Notes or the Facility, whichever is greater. As of December 31, 2024, our debt cover ratio was 2.54x. During the first quarter of 2025, the Facility lenders waived the requirement to maintain a restricted cash balance through 2025. As of December 31, 2025, our debt cover ratio was 5.49x. Our next financial covenant assessment date is March 31, 2026, after which date we will be required to restrict approximately $50.0 million in cash as required under the terms of the Facility unless otherwise waived by the lenders.

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 $17.2 million and $13.6 million in current joint interest billings receivables as of December 31, 2025 and 2024, respectively.

Inventories

Inventories consisted of $144.9 million and $167.5 million of materials and supplies and $27.7 million and $3.4 million of hydrocarbons as of December 31, 2025 and 2024, 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 $3.4 million, $1.8 million and $7.4 million during the years ended December 31, 2025, 2024 and 2023 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.

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 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 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 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. We also have used interest rate derivative contracts to mitigate our exposure to interest rate fluctuations related to our long-term debt. 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 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 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. Proved reserve quantities and future cash flows are estimated by independent petroleum engineering 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, 2025 and 2024, 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 separated from the host contract for accounting purposes. The host contract is the receivable from 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,		
	2025	2024	2023
		(In thousands)	
Revenues from contracts with customers:			
Ghana	$ 644,252	$ 1,052,126	$ 1,073,917
Equatorial Guinea	162,479	257,961	273,280
Mauritania|Senegal	116,800	—	—
Gulf of America	374,315	370,121	371,632
Total revenues from contracts with customers	1,297,846	1,680,208	1,718,829
Provisional sales contracts	(9,494)	(4,850)	(17,221)
Oil and gas revenue	$ 1,288,352	$ 1,675,358	$ 1,701,608

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 economic disruption resulting from Russia's continued war in Ukraine, ongoing instability in the Middle East and Latin America, 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. For our Gulf of America operations, crude oil and natural gas are transported to customers using third-party pipelines. Customers in our Gulf of America business unit that comprise 10% or more of our total consolidated oil and gas revenue for each of the below three years ended December 31, are shown below.

	Years ended December 31,		
	2025	2024	2023
		(Percentage)	
Customer			
BP Oil Supply	11%	10%	2%
Shell Trading (US) Company	10%	5%	14%

Recent Accounting Standards

Recently Adopted

In November 2023, the FASB issued "ASU 2023-07, "Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures." The amendment requires disclosures of significant segment expenses that are regularly provided to the chief operating decision maker ("CODM") and included within each reported measure of segment profit or loss, an amount and description of its composition for other segment items, and interim disclosures of a reportable segment's profit of loss and assets. The amendments are effective for fiscal years beginning after December 15, 2023, and for interim periods within fiscal years beginning after December 15, 2024 and were adopted on a retrospective basis for all prior periods presented in the financial statements. See Note 17 — Business Segment Information.

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 and were adopted on a retrospective basis for all periods presented in the financial statements. See Note 13 — Income Taxes.

Not Yet Adopted

In November 2024, FASB issued ASU 2024-03, "Income Statement - Reporting Comprehensive Income - Expense Disaggregation Disclosures (Subtopic 220-40): Disaggregation of Income Statement Expenses". The amendments in ASU 2024-03 require more detailed disclosures about specified categories of costs and expenses included in certain expense captions presented on the face of the income statement. This ASU is effective for fiscal years beginning after December 15, 2026, and for interim periods within fiscal years beginning after December 15, 2027. Early adoption is permitted. The Company is currently assessing the impact of this standard on its financial statement disclosures.

In November 2024, the FASB issued ASU 2024-04, "Debt - Debt with Conversion and Other Options (Subtopic 470-20): Induced Conversions of Convertible Debt Instruments." The amendments in ASU 2024-04 clarify the requirements for determining whether certain settlements of convertible debt instruments should be accounted for as an induced conversion. The amendments in the ASU are effective for annual periods beginning after December 15, 2025. Early adoption is permitted, however, we do not plan to early adopt ASU 2024-04. The Company is currently assessing the impact this standard will have on its consolidated financial statements.

3. Acquisitions and Divestitures

In October 2025, we submitted a formal notice to the Ministry of Hydrocarbons and Mining Development that we are electing to exit Block S offshore Equatorial Guinea.

On February 24, 2026, we entered into a Share Sale and Purchase Agreement with a subsidiary of Panoro Energy ASA for the sale of all of our participating interest in the Ceiba Field and Okume Complex production assets located in Block G offshore Equatorial Guinea for upfront cash consideration of $180.0 million, subject to certain adjustments, and future contingent consideration of up to $39.5 million. The transaction has received approval from the Government of Equatorial Guinea and completion only remains subject to CEMAC customary approval. While we expect to close the transaction around the middle of 2026, there can be no assurances that closing will ultimately occur or that it may not be delayed.

2024 Transactions

In March 2024, Kosmos completed the acquisition of an additional 16.7% participating interest in the Tiberius area in Keathley Canyon Blocks 920 and 964 offshore Gulf of America. As a result of the transaction, Kosmos' participating interest in Tiberius increased from 33.3% to 50.0%.

In December 2024, we submitted a formal notice to the Ministry of Hydrocarbons and Mining Development that we are electing to exit Block 21 offshore Equatorial Guinea.

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: 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%. Kosmos has worked with PETROSEN on potential development concepts for the field, along with identifying a suitable partner. Given we have not been able to attract a suitable partner and agree a commercially attractive development concept with the government of Senegal, we are working with PETROSEN to withdraw from the block.

4. Receivables

Receivables consisted of the following:

	December 31, 2025	December 31, 2024
	(In thousands)	
Joint interest billings, net	$ 17,255	$ 33,120
Oil and gas sales	56,700	89,694
Other current receivables	29,517	42,145
Total receivables	$ 103,472	$ 164,959
Long-term receivables	$ 458,793	$ 385,463

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 and production costs incurred for the GTA Phase 1 project through the Commercial Operations Date of the Gimi FLNG vessel. The Commercial Operations Date was achieved in June 2025 following the successful ramp-up to the daily contracted sales volume level under the Tortue Phase 1 SPA, equivalent to approximately 2.45 million tonnes per annum. As of December 31, 2025 and 2024, the principal balance due from the national oil companies was $355.5 million and $280.1 million, respectively, which is classified as Long-term receivables in our consolidated balance sheets. As of December 31, 2025 and 2024, accrued interest on the balance due from the national oil companies was $81.6 million and $56.6 million, respectively, which is classified as Long-term receivables in our consolidated balance sheets. Interest income on the long-term notes receivable was $25.0 million, $19.3 million and $15.9 million for the years ended December 31, 2025, 2024 and 2023, respectively.

5. Property and Equipment

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

	December 31, 2025	December 31, 2024
	(In thousands)	
Oil and gas properties:		
Proved properties	$ 8,301,679	$ 8,342,353
Unproved properties	210,161	386,292
Total oil and gas properties	8,511,840	8,728,645
Accumulated depletion	(4,780,826)	(4,288,215)
Oil and gas properties, net	3,731,014	4,440,430
Other property	68,255	66,675
Accumulated depreciation	(65,485)	(62,884)
Other property, net	2,770	3,791
Property and equipment, net	$ 3,733,784	$ 4,444,221

We recorded depletion expense of $517.1 million, $419.3 million and $411.6 million and depreciation expense of $2.6 million, $3.7 million and $3.7 million in our consolidated statement of operations for the years ended December 31, 2025, 2024 and 2023, respectively. In connection with fair value assessments for oil and gas proved properties, we recorded impairment of long-lived assets in our consolidated statement of operations totaling approximately $177.6 million related to the Winterfell and Marmalard fields in the Gulf of America, zero, and $222.3 million related to the TEN Fields in Ghana during the years ended December 31, 2025, 2024 and 2023, respectively. See Note 10 — Fair Value Instruments.

Additions to our proved properties during the year ended December 31, 2025 primarily related to development costs associated with the first phase of the GTA development in Mauritania and Senegal and infill development in the Jubilee Field in Ghana. Additionally, during the second quarter of 2025, the partnership drilled the Winterfell-4 step out well which was plugged and abandoned in September 2025 by the operator due to challenges during completion operations arising from the collapse of the production casing. As a result, all associated drilling and completion capitalized costs of approximately $58.5 million related to Winterfell-4 have been written off to exploration expense in our consolidated statement of operations for the year ended December 31, 2025. Additionally, the current phase of the Cayar Offshore Profound Block exploration license is set to expire in July 2026. Accordingly, during the year ended December 31, 2025, we wrote off $143.7 million of unproved property costs associated with the Yakaar and Teranga discoveries to exploration expense in our consolidated statement of operations.

Additions to our proved properties during the year ended December 31, 2024 primarily related to continued infill development drilling campaign in the Jubilee Field in Ghana, the Ceiba and Okume infill development drilling campaign in Equatorial Guinea, development costs associated with Phase 1 of the Greater Tortue Ahmeyim project in Mauritania and Senegal, the first phase of the Winterfell development project, and the Odd Job Field subsea pump installation in the Gulf of America offset by the non-cash settlement of the $200.2 million FPSO Contract Liability related to the deferred sale of the Greater Tortue FPSO against FPSO asset costs. Additionally, during the year ended December 31, 2024 we wrote off $37.6 million of capitalized exploratory costs associated with the S-5 exploration well.

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, 2025, 2024 and 2023.

	Years Ended December 31,		
	2025	2024	2023
	(In thousands)		
Beginning balance	$ 196,202	$ 211,959	$ 145,957
Additions to capitalized exploratory well costs pending the determination of proved reserves	19,132	21,418	66,002
Reclassification due to determination of proved reserves	—	—	—
Capitalized exploratory well costs charged to expense(1)	(142,193)	(37,175)	—
Ending balance	$ 73,141	$ 196,202	$ 211,959

(1) The current phase of the Cayar Offshore Profound Block exploration license is set to expire in July 2026. Accordingly, activity for the year ended December 31, 2025 represents the impairment of exploratory well costs associated with the Yakaar and Teranga discoveries. Activity for the year ended December 31, 2024 represents the impairment of exploratory well costs associated with the Asam discovery in Block S offshore Equatorial Guinea.

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,		
	2025	2024	2023
	(In thousands, except well counts)		
Exploratory well costs capitalized for a period of one year or less	$ —	$ —	$ 54,274
Exploratory well costs capitalized for a period of one to five years	73,141	63,552	34,775
Exploratory well costs capitalized for a period of six to ten years	—	132,650	122,910
Ending balance	$ 73,141	$ 196,202	$ 211,959
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	1	2	2

As of December 31, 2025, the project with exploratory well costs capitalized for more than one year since the completion of drilling is related to the Tiberius discovery located in Keathley Canyon Block 964 in the Outer Wilcox play in the Gulf of America.

Tiberius Discovery — In July 2023, we spud the Tiberius infrastructure-led exploration prospect located in Block 964 of Keathley Canyon in the Gulf of America, which encountered hydrocarbon pay. Initial fluid and core analysis supports the production potential of the well, which characteristics analogous with similar nearby discoveries in the Wilcox trend. In March 2024, we completed the acquisition of an additional 16.7% participating interest in the Keathley Canyon Blocks 920 and 964, offshore Gulf of America. As a result of the transaction, Kosmos' participating interest in the Tiberius discovery area increased from 33.3% to 50.0%. The Tiberius project is being analyzed as a phased development with discussions currently ongoing with our partner to finalize the development plan. Following additional evaluation, a final investment decision for the development of the project is expected to 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, 2025, 2024 and 2023 is as follows:

	December 31,		
	2025	2024	2023
	(In thousands)		
Operating lease cost	$ 4,276	$ 3,864	$ 3,866
Variable lease cost	2,074	1,963	1,766
Short-term lease cost(1)	3,557	12,281	17,464
Total lease cost	$ 9,907	$ 18,108	$ 23,096

(1) Includes $2.5 million, $10.7 million and $16.0 million during the years ended December 31, 2025, 2024 and 2023, respectively, of costs associated with short-term drilling contracts.

Other information related to operating leases at December 31, 2025 and 2024, is as follows:

	December 31,	
	2025	2024
	(In thousands, except lease term and discount rate)	
Balance sheet classifications		
Other assets (right-of-use assets)	$ 10,059	$ 12,294
Accrued liabilities (current maturities of leases)	2,777	2,816
Other long-term liabilities (non-current maturities of leases)	9,438	12,745
Weighted average remaining lease term	3.7 years	4.6 years
Weighted average discount rate	10.7 %	9.8 %

The table below presents supplemental cash flow information related to leases during the years ended December 31, 2025, 2024 and 2023:

	December 31,		
	2025	2024	2023
	(In thousands)		
Operating cash flows for operating leases	$ 7,339	$ 7,683	$ 7,256
Investing cash flows for operating leases(1)	2,528	10,746	16,029

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

Future minimum rental commitments under our leases at December 31, 2025, are as follows:

	Operating Leases(1)
	(In thousands)
2026	$ 3,923
2027	3,956
2028	3,744
2029	3,176
2030	—
Thereafter	—
Total undiscounted lease payments	$ 14,799
Less: Imputed interest	(2,584)
Total lease liabilities	$ 12,215

(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,	
	2025	2024
	(In thousands)	
Outstanding debt principal balances:		
Facility(2)	$ 1,200,000	$ 900,000
7.125% Senior Notes(2)	100,000	250,000
7.750% Senior Notes(2)	350,000	350,000
7.500% Senior Notes	400,274	400,274
8.750% Senior Notes	500,000	500,000
3.125% Convertible Senior Notes	400,000	400,000
GoA Term Loan Facility(2)	150,000	—
Total long-term debt	3,100,274	2,800,274
Unamortized deferred financing costs and discounts(1)	(47,515)	(55,562)
Total debt, net	3,052,759	2,744,712
Less: Current maturities of long-term debt	(132,143)	—
Long-term debt, net(2)	$ 2,920,616	$ 2,744,712

(1) Includes $24.3 million and $30.4 million of unamortized deferred financing costs related to the Facility, $10.4 million and $14.1 million of unamortized deferred financing costs and discounts related to the Senior Notes, $9.0 million and $11.1 million of unamortized deferred financing costs and discount related to the 3.125% Convertible Senior Notes, and $3.0 million and $0 of unamortized deferred financing costs related to the GoA Term Loan Facility as of December 31, 2025 and December 31, 2024, respectively.

(2) As of December 31, 2025, total long-term debt, net was $2.9 billion. In January 2026, we received net proceeds of $98.5 million from the funding of the second tranche of the GoA Term Loan Facility after deducting fees and expenses. The net proceeds were used, together with cash on hand, to fund the redemption of the remaining $100.0 million of the 7.125% Senior Notes due 2026. In January 2026, the Company also issued $350.0 million of 11.250% Senior Secured Bonds due 2031 in the Nordic market. In February 2026, Kosmos used a portion of the net proceeds from the offering to fund the repurchase of an aggregate principal amount of $182.5 million of the 7.750% Senior Notes due 2027 and to make a voluntary early principal repayment of $100.0 million on outstanding borrowings under the Facility.

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 September 2025, during the Fall 2025 redetermination, the Company's lending syndicate approved a borrowing base at the full Facility size of $1.35 billion. As of December 31, 2025, borrowings under the Facility totaled $1.2 billion and the undrawn availability under the Facility was $150.0 million. In February 2026, the Company used a portion of the net proceeds from the Nordic bond offering to make a voluntary early principal repayment of $100.0 million on outstanding borrowings under the Facility.

When our debt cover 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 7.750% Senior Notes, the 7.500% Senior Notes, the 8.750% Senior Notes and the 3.125% Convertible Senior Notes or the Facility, whichever is greater. As of December 31, 2024, our debt cover ratio was 2.54x. During the first quarter of 2025, the Facility lenders waived the requirement to maintain a restricted cash balance through 2025. As of December 31, 2025, our debt cover ratio was 5.49x. Our next financial covenant assessment date is March 31, 2026, after which date we will be required to restrict approximately $50.0 million in cash as required under the terms of the Facility unless otherwise waived by the lenders.

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. The Facility requires the Company to maintain certain financial covenants including:

- the field life cover ratio (as defined in the glossary), not less than 1.50x; and
- the loan life cover ratio (as defined in the glossary), not less than 1.10x through September 30, 2027 and 1.30x after September 30, 2027; 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.

In July 2025, the Company and the Facility lenders agreed to amend the debt cover ratio required under the Facility. The amendment made this covenant less restrictive for the two scheduled financial covenant assessment dates in September 2025 and March 2026, up to a maximum of 4.0x and 4.25x respectively, and returned to the originally agreed upon ratio of 3.50x for assessment dates thereafter. In February 2026, we further amended the debt cover ratio calculation through September 2026. This most recent amendment makes the covenant less restrictive for the two scheduled financial covenant assessment dates in March 2026 and September 2026, up to a maximum of 4.5x and 4.25x respectively, and for purposes of the financial covenant assessment date in March 2026, the calculation will be made excluding the Company's Mauritania and Senegal business unit. The debt cover ratio returns to the originally agreed upon ratio of 3.5x for assessment dates thereafter. The change is intended to align the covenant calculation with recent business operations, lower potential oil prices and the impact of operating costs during the ramp-up of the GTA Phase 1 project on our results of operations.

We were in compliance with the financial covenants above contained in the Facility, as amended, as of September 30, 2025 (the most recent assessment date). The Facility contains customary cross default provisions.

Interest on the Facility is the aggregate of the applicable margin (4.00% to 5.50%, 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. 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 April 1, 2027, outstanding borrowings will be constrained by an amortization schedule. The Facility has a final maturity date of December 31, 2029. As of December 31, 2025, 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.

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. In April 2024, in connection with the amendment and restatement of the Facility, we amended the Corporate Revolver reducing the borrowing capacity from $250.0 million to $165.0 million. In October 2024, pursuant to a voluntary cancellation notice sent by the Company, the Corporate Revolver was terminated.

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. On September 24, 2024, the Company completed the repurchase of an aggregate principal amount of $400.0 million of the 7.125% Senior Notes due 2026 pursuant to the Company's cash tender offers for portions of the 7.125% Senior Notes, the 7.750% Senior Notes, and the 7.500% Senior Notes announced on September 9, 2024. In October 2025, we used the proceeds from funding of the first tranche under the GoA Term Loan Facility, together with cash on hand, to fund the partial redemption of an additional aggregate principal amount of $150.0 million of the 7.125% Senior Notes. In January 2026, we used the proceeds from funding of the second tranche under the GoA Term Loan Facility, together with cash on hand, to complete the redemption of the remaining outstanding balance amount of $100.0 million of the 7.125% Senior Notes.

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 7.500% Senior Notes, the 8.750% Senior Notes and the 3.125% Convertible 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 Gulf of America assets, and on a subordinated, unsecured basis by certain subsidiaries that borrow under, or guarantee, the Facility and that guarantee the 7.500% Senior Notes, the 8.750% Senior Notes and the 3.125% Convertible Senior Notes. The 7.750% Senior Notes contain customary cross default provisions.

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.

On September 24, 2024, the Company completed the repurchase of an aggregate principal amount of $50.0 million of the 7.750% Senior Notes pursuant to the Company's cash tender offers for portions of the 7.125% Senior Notes, the 7.750% Senior Notes, and the 7.500% Senior Notes announced on September 9, 2024. In February 2026, the Company used a portion of the net proceeds from the Nordic bond offering to fund the repurchase of an aggregate principal amount of $182.5 million of the 7.750% Senior Notes pursuant to the Company's cash tender offer announced on January 12, 2026.

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 7.750% Senior Notes, the 8.750% Senior Notes and the 3.125% Convertible 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 Gulf of America assets, and on a subordinated, unsecured basis by certain subsidiaries that borrow under, or guarantee, the Facility and that guarantee the 7.750% Senior Notes, the 8.750% Senior Notes and the 3.125% Convertible Senior Notes. On September 24, 2024, the Company completed the repurchase of an aggregate principal amount of approximately $49.7 million of the 7.500% Senior Notes pursuant to the Company's cash tender offers for portions of the 7.125% Senior Notes, the 7.750% Senior Notes, and the 7.500% Senior Notes announced on September 9, 2024. The 7.500% Senior Notes contain customary cross default provisions.

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.

8.750% Senior Notes due 2031

In September 2024, the Company issued $500.0 million of 8.750% Senior Notes and received net proceeds of approximately $494.9 million after deducting fees. We used the net proceeds, together with cash on hand, to fund the Tender Offers and pay expenses related to the issuance of the 8.750% Senior Notes.

The 8.750% Senior Notes mature on October 1, 2031. Interest is payable in arrears each April 1 and October 1, commencing on April 1, 2025. The 8.750% 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 7.750% Senior Notes, the 7.500% Senior Notes and the 3.125% Convertible 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 8.750% Senior Notes are guaranteed on a senior, unsecured basis by certain subsidiaries owning the Company's Gulf of America assets and on a subordinated, unsecured basis by certain subsidiaries that borrow under, or guarantee, the Facility and that guarantee the 7.750% Senior Notes, the 7.500% Senior Notes and the 3.125% Convertible Senior Notes. The 8.750% Senior Notes contain customary cross default provisions.

At any time prior to October 1, 2027, and subject to certain conditions, the Company may, on one or more occasions, redeem up to 40% of the original principal amount of the 8.750% Senior Notes with an amount not to exceed the net cash proceeds of certain equity offerings at a redemption price of 108.750% of the outstanding principal amount of the 8.750% 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 October 1, 2027, the Company may, on any one or more occasions, redeem all or part of the 8.750% Senior Notes at a redemption price equal to 100%, plus any accrued and unpaid interest, and plus a "make-whole" premium. On and after October 1, 2027, the Company may redeem all or part of the 8.750% Senior Notes at the following redemption prices (expressed as a percentage of principal amount), plus accrued and unpaid interest, if any, on the notes redeemed during the twelve-month period indicated beginning on October 1 of the years indicated below:

Year	**Percentage**
2027	104.375 %
2028	102.188 %
2029 and thereafter	100.000 %

We may also redeem the 8.750% Senior Notes in whole, but not in part, at any time if changes in tax law impose certain withholding taxes on amounts payable of the 8.750% Senior Notes at a price equal to the principal amount of the 8.750% 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 8.750% 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 8.750% Senior Notes indenture, the Company will be required to make an offer to repurchase the 8.750% 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 8.750% Senior Notes indenture, we will be required to use the net proceeds to make an offer to purchase the 8.750% Senior Notes at an offer price in cash in an amount equal to 100% of the principal amount of the 8.750% Senior Notes, plus accrued an unpaid interest to, but excluding, the repurchase date.

The 8.750% 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. Certain of these covenants will be terminated if the 8.750% 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.

3.125% Convertible Senior Notes due 2030

In March 2024, the Company issued $400.0 million of 3.125% Convertible Senior Notes (the "3.125% Convertible Senior Notes") and received net proceeds of $390.4 million after deducting fees.

The 3.125% Convertible Senior Notes mature on March 15, 2030, unless earlier converted, redeemed or repurchased. Interest is payable in arrears each March 15 and September 15, commencing September 15, 2024. The 3.125% Convertible 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 7.750% Senior Notes, the 7.500% Senior Notes and the 8.750% 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, to the extent of the value of the assets securing such indebtedness). The 3.125% Convertible Senior Notes are guaranteed on a senior, unsecured basis by certain of our existing subsidiaries that guarantee on a senior basis the 7.750% Senior Notes, the 7.500% Senior Notes and the 8.750% Senior Notes, and, in certain circumstances, certain of our other existing or future subsidiaries. The 3.125% Convertible Senior Notes are guaranteed on a subordinated, unsecured basis by certain or existing subsidiaries that borrow under or guarantee the Facility and guarantee on a subordinated basis the 7.750% Senior Notes, the 7.500% Senior Notes and the 8.750% Senior Notes, and, in certain circumstances, certain of our other existing or future subsidiaries.

Holders of the 3.125% Convertible Senior Notes may convert all or any portion of their 3.125% Convertible Senior Notes at their option at any time prior to the close of business on the business day immediately preceding December 15, 2029 only under the following circumstances:

- during any calendar quarter commencing after the calendar quarter ending on June 30, 2024 (and only during such calendar quarter), if the last reported sale price of our common stock for at least 20 trading days (whether or not consecutive) during a period of 30 consecutive trading days ending on, and including, the last trading day of the immediately preceding calendar quarter is greater that or equal to 130% of the conversion price on each applicable trading day;
- during the five business day period after any five consecutive trading day period (the "measurement period") in which the trading price per $1,000 principal amount of 3.125% Convertible Senior Notes for each trading day of the measurement period was less that 98% of the product of the last reported sale price of our common stock and the conversion rate on each such trading day;
- if we call any or all of the 3.125% Convertible Senior Notes for redemption, the 3.125% Convertible Senior Notes called (or deemed called) for redemption may be converted at any time prior to the close of business on the second scheduled trading day immediately preceding the redemption date; or
- upon the occurrence of certain specified corporate events.

On or after December 15, 2029 until the close of business on the second scheduled trading day immediately preceding the maturity date, holders may convert at any time all or a portion of their 3.125% Convertible Senior Notes at the option of the holder.

The conversion rate for the 3.125% Convertible Senior Notes is initially 142.4501 share of common stock per $1,000 principal amount of 3.125% Convertible Senior Notes (which is equivalent to an initial conversion price of approximately $7.02 per share of our common stock), subject to adjustments.

Upon conversion, we will pay cash up to the aggregate principal amount of the 3.125% Convertible Senior Notes to be converted and pay or deliver, as the case may be, cash, shares of our common stock or a combination of cash and shares of our common stock, at our election in respect of the remainder, if any, of our conversion obligation in excess of the aggregate principal amount of the 3.125% Convertible Senior Notes being converted. The amount of cash and shares of our common stock, if any, due upon conversion will be based on a daily conversion value calculated on a proportionate basis for each trading day in a 40 consecutive trading day observation period.

In addition, following certain corporate events that occur prior to the maturity date or if we deliver a notice of redemption, we will, in certain circumstances, increase the conversion date for a holder who elects to convert its 3.125% Convertible Senior Notes in connection with such a corporate event or to convert its 3.125% Convertible Senior Notes called (or deemed called) for redemption in connection with such notice of redemption, as the cause may be.

Other than in connection with certain tax law changes, we may not redeem the notes prior to March 22, 2027. We may redeem for cash all or any portion of the 3.125% Convertible Senior Notes, at our option, on or after March 22, 2027 and prior to the 41st scheduled trading day immediately preceding the maturity date, if the last reported sale price of our common stock has been at least 130% of the conversion price then in effect for at least 20 trading days (whether or not consecutive), including the trading day immediately preceding the date on which the Company provides notice of redemption, during an 30 day consecutive trading day period ending on, and including, the trading day immediately preceding the date on which we provide the related notice of redemption, at a redemption price equal to 100% of the principal amount of the 3.125% Convertible Senior Notes to be redeemed, plus accrued and unpaid interest to, but excluding, the redemption date. We are not required to redeem or retire the 3.125% Convertible Senior Notes periodically. We may not elect to redeem less than all of the outstanding 3.125% Convertible Senior Notes unless at least $75.0 million aggregate principal amount of 3.125% Convertible Senior Notes are outstanding and not subject to redemption as of the time we send the related redemption notice. The 3.125% Convertible Senior Notes indenture contains customary terms and covenants.

The Company recorded the 3.125% Convertible Senior Notes, including the debt itself and all embedded derivatives, at cost less debt issuance costs of $9.6 million and has presented the 3.125% Convertible Senior Notes as a single financial instrument in Long-term debt, net in our consolidated balance sheet. No portion of the embedded derivative required bifurcation from the host debt contract. As of December 31, 2025, the effective annual interest rate on the 3.125% Convertible Senior Notes is approximately 3.70%, including amortization of debt issuance costs.

Capped Call Transactions

In connection with the issuance of the 3.125% Convertible Senior Notes, the Company used $49.8 million of the net proceeds from the issuance of the 3.125% Convertible Senior Notes to enter into capped call transactions (the "Capped Call Transactions"). The Capped Call Transactions are generally expected to reduce potential dilution to holders of our common stock upon any conversion of the 3.125% Convertible Senior Notes and/or offset any cash payments that we are required to make in excess of the principal amount of any 3.125% Convertible Senior Notes that are converted, as the case may be, with such reduction and/or offset subject to a cap.

The Capped Call Transactions have an initial cap price of $10.80 per share, which represents a premium of 100% over the last reported sale price of our common stock on March 5, 2024, and is subject to certain adjustments under the terms of the Capped Call Transactions. The Capped Call Transactions cover, initially, the number of shares of our common stock underlying the 3.125% Convertible Senior Notes, subject to anti-dilution adjustments substantially similar to those applicable to the conversion rate of the 3.125% Convertible Senior Notes.

The Capped Call Transactions qualify for a derivative scope exception as they are indexed to our common stock and are not required to be accounted for as a separate derivative. Consequently, the Capped Call Transactions have been included as a net reduction to additional-paid-in-capital within stockholders' equity in our consolidated balance sheet and do not require subsequent remeasurement.

GoA Term Loan Facility

On September 24, 2025, the Company entered into a senior secured term loan credit agreement secured by first priority liens on all of the Company's Gulf of America assets (as defined in the Credit Agreement). The GoA Term Loan Facility is a four-year term loan structured in two tranches, with the first tranche a principal amount of $150.0 million, which was funded on October 1, 2025, and a second tranche comprising commitments to lend up to an additional $100.0 million, available for drawing until April 1, 2026. On October 1, 2025, we received net proceeds of $147.2 million from funding of the first tranche after deducting fees and other expenses. On October 6, 2025, the net proceeds were used, together with cash on hand, to fund the redemption of a portion of the 7.125% Senior Notes due 2026 totaling $150.0 million in aggregate. On January 12, 2026, we received net proceeds of $98.5 million from the funding of the second tranche after deducting fees and expenses. On January 13, 2026, the net proceeds were used, together with cash on hand, to complete the redemption of the remaining outstanding balance of $100.0 million of the 7.125% Senior Notes due 2026.

Interest on outstanding loans under the GoA Term Loan Facility is payable quarterly in arrears at a rate per annum equal to 3.75% plus the term SOFR reference rate administered by CME Group Benchmark Administration Limited for the relevant period published. The GoA Term Loan Facility is now fully drawn and matures in 2029, with principal payments beginning June 30, 2026.

The GoA Term Loan Facility contains customary affirmative and negative covenants, including the affect our ability to incur additional indebtedness, create liens, merge, dispose of assets, and make distributions, dividends, investments or capital expenditures, among other things. The GoA Term Loan Facility requires the Company to maintain certain financial covenants including:

- the GoA field life coverage ratio (as defined in the glossary), not less than 1.50x; and
- the GoA net leverage ratio (as defined in the glossary), not more than 3.50x and

The GoA Term Loan Facility includes certain representations and warranties, indemnities and events of default that, subject to materiality thresholds and grace periods, arise as a result of a payment of default, failure to comply with covenants, material inaccuracy or representation or warranty, and certain bankruptcy or insolvency proceedings. If there is an event of default, all or any portion of the outstanding indebtedness may be immediately due and payable and other rights may be exercised including against the collateral.

GTA Nordic bonds

In January 2026, the Company issued $350.0 million of 11.250% senior secured bonds due 2031 in the Nordic market (the "GTA Nordic bonds"). In February 2026, Kosmos used a portion of the net proceeds from the offering to fund the repurchase of an aggregate principal amount of $182.5 million of the 7.750% Senior Notes pursuant to the Company's cash tender offer announced on January 12, 2025 and to make a voluntary early principal repayment of $100.0 million on outstanding borrowings under the Facility, with the remaining proceeds to be used for future retirements of the 7.750% Senior Notes due 2027.

The GTA Nordic bonds mature in January 2031. Interest is payable semi-annually in arrears each July 29 and January 29, commencing on July 29, 2026. The GTA Nordic bonds were issued by Kosmos Energy GTA Holdings, a wholly-owned subsidiary of Kosmos Energy Ltd., and are fully and unconditionally guaranteed by the Company and the Company's wholly-owned subsidiaries, Kosmos Energy Tortue Finance, Kosmos Energy Senegal, Kosmos Energy Investments Senegal Limited and Kosmos Energy Mauritania. The GTA Nordic bonds are also guaranteed on an unsecured basis by certain of the Company's subsidiaries that also guarantee the Company's existing senior unsecured notes.

At any time prior to July 29, 2028, the Company may, on any one or more occasions, redeem all or part of the GTA Nordic bonds at a redemption price equal to 100%, plus any accrued and unpaid interest, and plus a "make-whole" premium. On and after July 29, 2028, the Company may redeem all or part of the GTA Nordic bonds at the following redemption prices (expressed as a percentage of principal amount), plus accrued and unpaid interest, if any, on the notes redeemed:

Year	**Percentage**
July 29, 2028 to, but not including, July 29, 2029	105.625 %
July 29, 2029 to, but not including, January 29, 2030	103.375 %
January 29, 2030 and thereafter	100.000 %

If the Company's shares are no longer listed on the New York Stock Exchange or upon the occurrence of a change of control event, as defined in the Bond Terms for the GTA Nordic bonds, each Nordic bondholder shall have a right to require that the Company repurchase all or some of the GTA Nordic bonds held by that Nordic bondholder (a "Put Option") at a repurchase price equal to 101% of the principal amount, plus accrued and unpaid interest to, but excluding, the date of repurchase. If more than 90% of the outstanding GTA Nordic bonds have been repurchased as a result of the exercise of the Put Option, the Company will be entitled to repurchase all the remaining GTA Nordic bonds at a price equal to 101% of the principal amount.

The Bond Terms governing the GTA Nordic bonds restrict the ability of Kosmos Energy GTA Holdings, Kosmos Energy Tortue Finance, Kosmos Energy Senegal, Kosmos Energy Investments Senegal Limited and Kosmos Energy Mauritania to, among other things: incur or guarantee additional indebtedness, create liens, sell assets, enter into transactions with affiliates, or effect certain consolidations, mergers or amalgamations.

The Bond Terms governing the GTA Nordic bonds also require Kosmos Energy GTA Holdings to maintain certain financial covenants including:

- Minimum Liquidity (as defined in the Bond Terms) of not less than $17.5 million or 5% of the outstanding GTA Nordic bonds, whichever is greater; and
- an Asset Coverage Ratio (as defined in the Bond Terms) of at least 1.25x.

Principal Debt Repayments

At December 31, 2025, the estimated repayments of debt during the five fiscal year periods and thereafter are as follows:

	Payments Due by Year						
	Total	2026(2)	2027(2)	2028	2029	2030	Thereafter
	(In thousands)						
Principal debt repayments(1)	$ 3,100,274	$ 132,143	$ 713,306	$ 828,639	$ 526,186	$ 400,000	$ 500,000

(1) Includes the scheduled maturities for outstanding principal debt balances. The scheduled maturities of debt related to the Facility as of December 31, 2025 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.

(2) In January 2026, we used net proceeds of $98.5 million from the funding of the second tranche of the GoA Term Loan Facility, together with cash on hand, to fund the redemption of the remaining $100.0 million of the 7.125% Senior Notes due 2026. In January 2026, the Company also issued $350.0 million of 11.250% Senior Secured Bonds due 2031 in the Nordic market. In February 2026, Kosmos used a portion of the net proceeds from the Nordic bond offering to fund the repurchase of an aggregate principal amount of $182.5 million of the 7.750% Senior Notes due 2027and to make a voluntary early principal repayment of $100.0 million on outstanding borrowings under the Facility.

Interest and other financing costs, net

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

	Years Ended December 31,		
	2025	2024	2023
	(In thousands)		
Interest expense	$ 229,322	$ 214,440	$ 207,629
Amortization—deferred financing costs	7,886	8,709	9,921
Debt modifications and extinguishments	195	25,173	1,503
Capitalized interest	(16,492)	(168,715)	(138,738)
Deferred interest	(214)	(281)	3,183
Interest income	(30,613)	(24,129)	(19,456)
Other, net	33,346	33,401	31,862
Interest and other financing costs, net	$ 223,430	$ 88,598	$ 95,904

Cash payments for interest totaled $223.5 million, $194.8 million and $213.4 million for the years ended December 31, 2025, 2024 and 2023. Capitalized interest for the years ended December 31, 2025, 2024 and 2023 was $16.5 million, $168.7 million and $138.7 million, respectively. The decrease in capitalized interest during the year ended December 31, 2025 compared to 2024 is primarily due to the achievement of first gas production on the GTA Phase 1 project on December 31, 2024, after which we 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, 2025. Volumes and weighted average prices are net of any offsetting derivative contracts entered into.

Term	Type of Contract	Index	MBbl	Weighted Average Price per Bbl				
				Net Deferred Premium Payable/ (Receivable)	Swap	Sold Put	Floor	Ceiling
2026:								
Jan - Jun	Two-way collars	Dated Brent	1,000	$ 1.55	$ —	$ —	$ 60.00	$ 74.75
Jan - Dec	Three-way collars	Dated Brent	2,000	—	—	50.00	60.00	75.51
Jan - Jun	Swaps(1)	Dated Brent	1,000	—	72.90	—	—	80.00
Jan - Dec	Swaps(1)	Dated Brent	1,000	—	72.46	—	—	80.00
Jan - Dec	Swaps(1)	Dated Brent	2,000	—	69.70	55.00	—	—
Jan - Dec	Swaps(1)	NYMEX WTI	1,500	—	64.83	50.00	—	—

(1) Includes call option contracts sold to counterparties to enhance Swaps.

In January 2026, we entered into Dated Brent three-way collar contracts for 2.0 MMBbl from January 2027 through December 2027 with a weighted average sold put price of $47.50 per barrel, a floor price of $60.00 per barrel and a ceiling price of $75.00 per barrel.

The following tables disclose the Company's derivative instruments as of December 31, 2025 and 2024 and gain/(loss) from derivatives during the years ended December 31, 2025, 2024 and 2023.

Type of Contract	Balance Sheet Location	Estimated Fair Value Asset (Liability) December 31, 2025	2024
		(In thousands)	
Derivatives not designated as hedging instruments:			
Derivative assets:			
Commodity	Derivatives assets—current	$ 47,816	$ 6,714
Provisional sales contracts	Receivables: Oil and gas sales	—	2,242
Interest rate	Derivatives assets—current	—	2,202
Commodity	Derivatives assets—long-term	2,681	512
Total derivatives not designated as hedging instruments		$ 50,497	$ 11,670

Type of Contract	Location of Gain/(Loss)	Amount of Gain/(Loss) Years Ended December 31, 2025	2024	2023
		(In thousands)		
Derivatives not designated as hedging instruments:				
Provisional sales contracts	Oil and gas revenue	$ (9,494)	$ (4,850)	$ (17,221)
Commodity	Derivatives, net	53,665	(12,099)	(11,128)
Interest rate	Interest expense	837	2,202	—
Total derivatives not designated as hedging instruments		$ 45,008	$ (14,747)	$ (28,349)

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, 2025 and 2024, 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, 2025 and 2024, 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, 2025				
Assets:				
Commodity derivatives	$ —	$ 50,497	$ —	$ 50,497
Decommissioning trust fund:				
Debt securities	—	23,707	—	23,707
Total	$ —	$ 74,204	$ —	$ 74,204
December 31, 2024				
Assets:				
Commodity derivatives	$ —	$ 7,226	$ —	$ 7,226
Provisional sales contracts	—	2,242	—	2,242
Interest rate derivatives	—	2,202	—	2,202
Decommissioning trust fund:				
Debt securities	—	10,653	—	10,653
Total	$ —	$ 22,323	$ —	$ 22,323

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, call options and swaps 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 Sales Contracts

The value attributable to provisional sales contracts 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.

Interest Rate Derivatives

Our interest rate derivatives in 2024 consisted of interest rate swaps, whereby the Company pays a fixed rate of interest and the counterparty pays a variable SOFR-based rate. The values attributable to the Company's interest rate derivative contracts are based on (i) the contracted notional amounts, (ii) SOFR yield curves provided by independent third parties and corroborated with forward active market-quoted SOFR yield curves and (iii) a credit-adjusted yield curve as applicable to each counterparty by reference to the CDS market.

Decommissioning Trust Fund

In April 2024, a decommissioning trust agreement with the Jubilee unit partners to cash fund future retirement costs associated with the Jubilee Field was finalized. Each partner will contribute annually to the trust in proportion to its respective paying interest of the estimated future dismantlement, abandonment and restoration costs associated with the decommissioning of the Jubilee Field. Contributions to the trust are used by the trustee of the fund, the Bank of Ghana, to purchase and sell authorized securities at the direction of the Jubilee unit partners.

As of December 31, 2025, the investments held in the decommissioning trust fund are US Treasury debt securities. We have classified the investments as trading securities and recorded such investments at their fair market value as other long-term assets in our consolidated balance sheet using observable inputs including Kosmos' share of the fund and broker/dealer bid/ask prices of the investments held by the fund at December 31, 2025. Contributions made to the decommissioning trust are reported as investing activities in our consolidated statement of cash flows. All realized and unrealized gains and losses resulting from the sales and maturities or changes in fair value of the securities are recognized in Other income, net. For the years ended December 31, 2025 and 2024, we contributed $11.5 million and $11.5 million to the decommissioning trust fund, respectively.

The following table summarizes the cost and fair value, purchases, proceeds from the sales and maturities, and the unrealized gains (losses) for Kosmos' portion of the investments in debt securities held by the decommissioning trust at December 31, 2025 and 2024:

Type of Security	Years Ended Purchases	Net Proceeds (1)	Unrealized Gain (Loss)
2025			
Debt securities	$ 12,857	$ —	$ 197
Cash and cash equivalents	—	(749)	—
Other(1)	—	171	—
Total	$ 12,857	$ (578)	$ 197
2024			
Debt securities	$ 10,708	$ —	$ (55)
Cash and cash equivalents	—	752	—
Other(1)	—	101	—
Total	$ 10,708	$ 853	$ (55)

(1) Represents net receivables relating to interest.

The following table presents the costs and fair values of investments in debt securities held in the decommissioning trust fund according to the contractual maturities at December 31, 2025 and 2024:

	December 31, 2025		December 31, 2024	
	Cost	Estimated Fair Value	Cost	Estimated Fair Value
	(In thousands)			
Less than 5 years	$ 23,565	$ 23,707	$ 10,708	$ 10,653
5 years to 10 years	—	—	—	—
Due after 10 years	—	—	—	—
Total	$ 23,565	$ 23,707	$ 10,708	$ 10,653

Debt

The following table presents the carrying values and fair values at December 31, 2025 and 2024:

	December 31, 2025		December 31, 2024	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In thousands)			
7.125% Senior Notes	$ 99,942	$ 99,303	$ 249,315	$ 246,565
7.750% Senior Notes	348,757	321,394	347,910	339,927
7.500% Senior Notes	398,426	270,125	397,672	379,404
8.750% Senior Notes	495,564	283,575	494,997	470,965
3.125% Convertible Senior Notes	393,097	172,704	391,603	332,792
GoA Term Loan Facility	150,000	150,000	—	—
Facility	1,200,000	1,200,000	900,000	900,000
Total	$ 3,085,786	$ 2,497,101	$ 2,781,497	$ 2,669,653

The carrying values of our 7.125% Senior Notes, 7.750% Senior Notes, 7.500% Senior Notes, 8.750% Senior Notes and 3.125% Convertible Senior Notes represent the principal amounts outstanding less unamortized discounts. The fair values of our 7.125% Senior Notes, 7.750% Senior Notes, 7.500% Senior Notes, 8.750% Senior Notes and 3.125% Convertible Senior Notes are based on quoted market prices, which results in a Level 1 fair value measurement. The carrying values of the 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 gas reserve revisions at the Winterfell and Marmalard fields in the Gulf of America, primarily driven by a change in the planned development work scope for the fields, we reviewed the Winterfell and Marmalard long-lived assets for impairment at December 31, 2025, which resulted in impairment of long lived assets in our consolidated statement operations of approximately $177.6 million for the year ended December 31, 2025, reducing the carrying value of the proved properties to their estimated fair value of $64.4 million as of December 31, 2025. As part of our impairment analysis, the average per barrel WTI price of third-party industry forecasts used for purposes of determining discounted future cash flows was in the mid-$60s adjusted for inflation. The expected future cash flows were discounted using a rate of approximately ten 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 ended December 31, 2024.

As a result of negative proved oil and 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 ten 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.

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,	
	2025	**2024**
	(In thousands)	
Asset retirement obligations:		
Beginning asset retirement obligations	$ 407,011	$ 346,786
Liabilities incurred during period	1,732	23,104
Liabilities settled during period	(3,803)	(1,675)
Revisions in estimated retirement obligations	(104,506)	4,953
Accretion expense	37,063	33,843
Ending asset retirement obligations	$ 337,497	$ 407,011

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 liabilities incurred during 2025 are related to the infill drilling programs in the Jubilee Field in Ghana and the Winterfell development in the Gulf of America. The revisions in estimated retirement obligations during 2025 are primarily related to the change in estimated timing as a result of the license extensions of the WCTP and DT Petroleum Agreements in Ghana. The Ghana partnership received approval from the Government of Ghana in December 2025 for license extensions. Accordingly, the WCTP and DT licenses have been extended to 2040. The revisions in estimated retirement obligations during 2025 are also related to changes in the estimated timing, scopes of work and costs. The revision in estimated retirement obligations during 2024 are related to changes in the estimated timing, scopes of work and costs. The liabilities incurred during 2024 are related to the infill drilling programs in the Jubilee Field in Ghana and the Ceiba and Okume Complex in Equatorial Guinea, the Winterfell development in the Gulf of America and the Greater Tortue Ahmeyim Phase 1 development project in Mauritania and Senegal.

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, 2025, the Company had approximately 4.3 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, 2025:

	Service Vesting Restricted Stock Units	Weighted-Average Grant-Date Fair Value	Market / Service Vesting Restricted Stock Units	Weighted-Average Grant-Date Fair Value
	(In thousands)		(In thousands)	
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
Granted(1)	4,481	6.22	6,232	8.58
Forfeited(1)	(386)	6.31	(485)	9.57
Vested	(4,052)	3.02	(9,351)	3.91
Outstanding at December 31, 2024:	4,753	6.36	8,766	9.07
Granted(1)	3,210	3.23	3,945	4.93
Forfeited(1)	(492)	5.46	(572)	7.88
Vested	(2,398)	6.07	(4,034)	6.97
Outstanding at December 31, 2025:	5,073	4.59	8,105	8.42

(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, 2025, total equity-based compensation to be recognized on unvested restricted stock units is $18.0 million over a weighted average period of 1.6 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 4.2%. The expected quarterly dividends ranged from $0.00 to $0.05 commensurate with our current dividend experience.

In January 2026, we granted 2.4 million service vesting restricted stock units and 6.0 million market and service vesting restricted stock units to our employees under our long-term incentive plan. We expect to recognize approximately $14.7 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,		
	2025	2024	2023
		(In thousands)	
Share-based compensation expense	$ 27,953	$ 37,951	$ 42,693
Total tax benefit	5,113	6,184	7,482
Net tax shortfall (windfall)	3,459	(9,562)	(3,201)
Fair value of awards vested	19,918	82,317	45,098

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, 2025, our net deferred tax liability decreased by approximately $6.7 million primarily as a result of a proved property impairment charge of $177.6 million during the year ended December 31, 2025 as a result of negative proved oil and gas reserves revisions in certain of our Gulf of America fields, including Winterfell, partially offset by timing of reversal of temporary differences. During the year ended December 31, 2024, our net deferred tax liability decreased by approximately $52.1 million primarily as a result of a tax change in Equatorial Guinea (discussed below) and the timing reversal of temporary differences. 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 approximately $77.8 million, and a $29.8 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,		
	2025	2024	2023
		(In thousands)	
United States	$ (398,281)	$ (162,243)	$ (88,458)
Foreign	(236,300)	512,055	460,193
Income (loss) before income taxes	$ (634,581)	$ 349,812	$ 371,735

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

	Years Ended December 31,		
	2025	2024	2023
		(In thousands)	
Current:			
United States	$ (6)	$ (1,074)	$ 865
Foreign	71,949	213,209	264,910
Total current	71,943	212,135	265,775
Deferred:			
United States	(6,236)	2,933	551
Foreign	(502)	(55,107)	(108,111)
Total deferred	(6,738)	(52,174)	(107,560)
Income tax expense	$ 65,205	$ 159,961	$ 158,215

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. The reconciliation has been prepared in accordance with the disclosure requirements of ASU 2023-09, Income Taxes" Improvements to income tax disclosures, which the Company has adopted retrospectively for all periods presented.

	Years Ended December 31,					
	2025		2024		2023	
	Amount	Percentage	Amount	Percentage	Amount	Percentage
	(In thousands, except percentages)					
Profit before taxes	$(634,581)		$ 349,812		$371,735	
United States federal tax rate	21 %		21 %		21 %	
Tax at United States federal tax	(133,262)	21 %	73,461	21 %	78,064	21 %
State and local income tax(1)	68	— %	137	— %	959	— %
Ghana						
Foreign operations taxed at a different rate	34,135	(5 %)	84,078	24 %	49,655	13 %
Other	24	— %	(366)	— %	(1,433)	— %
Uncertain Tax Positions	(538)	— %	(7,963)	(2) %	—	— %
Equatorial Guinea						
Foreign operations taxed at a different rate	(2,495)	— %	(547)	— %	12,545	3 %
Change in valuation allowance:	3,812	(1 %)	1,793	1 %	4,094	1 %
Other	(79)	— %	373	— %	199	— %
Change in statutory tax rate	—	— %	(42,017)	(12) %	—	— %
Mauritania						
Foreign operations taxed at a different rate	(5,632)	1 %	(3,470)	(1 %)	(940)	— %
Change in Valuation Allowance	17,321	(3 %)	15,402	4 %	4,023	1 %
Other	8,025	(1 %)	214	— %	209	— %
Senegal						
Foreign operations taxed at a different rate	(11,453)	2 %	(6,279)	(2 %)	(1,433)	— %
Change in Valuation Allowance	39,317	(5 %)	20,658	6 %	5,318	1 %
Other	3,169	— %	2,636	1 %	—	— %
Cayman Islands						
Foreign operations taxed at a different rate	36,765	(6 %)	(11,091)	(3 %)	(11,197)	(3 %)
Other	(2,354)	— %	(862)	— %	—	— %
Other Foreign Jurisdictions						
Foreign operations taxed at a different rate	(47)	— %	(152)	— %	(85)	— %
Change in Valuation Allowance	399	— %	1,197	— %	903	— %
Other	710	— %	(3,107)	(1) %	(1,697)	— %
Non-deductible and other items:						
Share-Based Compensation	3,916	(1 %)	(1,060)	— %	2,465	1 %
Other	152	— %	(372)	— %	1,732	— %
Effects of cross-border tax laws:						
Foreign-derived intangible income	—	— %	—	— %	(424)	— %
Subpart F	—	— %	4,170	1 %	3,328	1 %
Tax Credits	—	— %	—	— %	(157)	— %
Change in valuation allowance:	73,250	(12 %)	33,128	9 %	12,089	3 %
Total tax expense	$ 65,205	(10) %	$ 159,961	46 %	$158,215	43 %

(1) For years ended December 2025, 2024, and 2023 the majority of state taxes are made up of Texas & Louisiana.

The effective tax rate for the United States is approximately 2%, (1%) and (2)% for the years ended December 31, 2025, 2024 and 2023, 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, 2025, 2024 and 2023, our effective tax rate in the United States is impacted by increases/(decreases) in valuation allowances on a portion of our deferred tax assets totaling $73.3 million, $33.1 million and $12.1 million, respectively.

The effective tax rate for Ghana is approximately 35%, 35% and 36% for the years ended December 31, 2025, 2024 and 2023, respectively. The effective tax rate in Ghana is impacted by non-deductible expenditures.

The effective tax rate for our producing entity in Equatorial Guinea is approximately 21%, (68)% and 35% for the years ended December 31, 2025, 2024 and 2023, respectively, and is impacted by non-deductible expenditures. Equatorial Guinea changed the statutory rate from 35% to 25%, with an effective date of January 1, 2025. We remeasured the net deferred tax liability during the fourth quarter of 2024 which impacted the effective tax rate for the year.

Our operations in other foreign jurisdictions have a 0% effective tax rate because they reside in countries with minimal activity, 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,	
	2025	**2024**
	(In thousands)	
Deferred tax assets:		
Foreign capitalized operating expenses	$ 253,612	$ 247,306
Foreign net operating losses	181,215	34,764
United States net operating losses	107,110	96,945
United States deferred interest expense	86,253	69,051
Equity compensation	9,372	11,164
Asset retirement obligation and other	65,589	98,056
Total deferred tax assets	703,151	557,286
Valuation allowance	(531,696)	(405,831)
Total deferred tax assets, net	171,455	151,455
Deferred tax liabilities:		
Depletion, depreciation and amortization related to property and equipment	(422,811)	(411,234)
Other deferred tax liabilities	(50,623)	(48,937)
Total deferred tax liabilities	(473,434)	(460,171)
Net deferred tax liability	$ (301,979)	$ (308,716)

The Company has foreign net operating loss carryforwards of $653.3 million. Of these losses, we expect $42.5 million to expire in 2028, $67.4 million to expire in 2029, $237.9 million to expire in 2030, and, $305.5 million will not expire. Additionally, the Company has $510.0 million of United States net operating loss that will not expire. Majority of the losses within the US & Foreign Jurisdictions currently have offsetting valuation allowances.

The Company is open to tax examinations in the United States for federal income tax return years 2022 through 2024, in Ghana for income tax return years 2021 through 2024, in Equatorial Guinea for income tax return years 2021 through 2024, in the United Kingdom for income tax years 2022 through 2024, in Senegal for income tax years 2021 through 2024, and in Mauritania from 2022 through 2024.

As of December 31, 2025, 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.

The Company had cash taxes paid (net of refunds) during the year ended December 31, 2025 as follows:

	December 31,		
	2025	2024	2023
Incomes taxes paid:	(In thousands)		
Ghana	$ 109,891	$ 247,078	$ 196,890
Equatorial Guinea	2,125	33,763	82,993
Other Jurisdictions	(958)	164	1,989
	$ 111,058	$ 281,005	$ 281,872

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,		
	2025	2024	2023
	(In thousands, except per share data)		
Numerator:			
Net income (loss) allocable to common stockholders	$ (699,786)	$ 189,851	$ 213,520
Denominator:			
Weighted average number of shares outstanding:			
Basic	477,591	470,844	459,641
Restricted stock units(1)	—	5,847	21,429
Shares issuable assuming conversion of 3.125% Convertible Senior Notes(3)	—	—	—
Diluted(2)	477,591	476,691	481,070
Net income (loss) per share:			
Basic	$ (1.47)	$ 0.40	$ 0.46
Diluted(2)	$ (1.47)	$ 0.40	$ 0.44

(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, 2025, 2024 and 2023, we excluded 6.8 million, 3.3 million and 0.0 million outstanding restricted stock units, respectively, from the computations of diluted net income per share because the effect would have been anti-dilutive.

(3) Represents the dilutive impact for the Company's 3.125% Convertible Senior Notes due 2030. As of December 31, 2025, the if-converted value is less than the outstanding principal of the 3.125% Convertible Senior Notes and therefore anti-dilutive. The 3.125% Convertible Senior Notes are subject to a capped call arrangement that potentially reduces the dilutive effect. Any potential impact of the capped call arrangement is excluded from this table as any proceeds under the capped call arrangement are considered 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 that the likelihood of an unfavorable outcome having a material impact is neither reasonably possible nor probable of occurring.

As of December 31, 2025, we have a commitment to drill one development well in Equatorial Guinea. As part of the license extensions of WCTP and DT Petroleum Agreements in Ghana, we have a commitment to drill a minimum of ten development wells under the amended Jubilee plan of development.

In April 2024, a decommissioning trust agreement with the Jubilee unit partners to cash fund future retirement costs associated with the Jubilee Field was finalized. The operator currently estimates the total remaining commitment to be approximately $122.6 million as of December 31, 2025, net to Kosmos, which will be funded annually by Kosmos over an estimated fifteen year period based on the expiration date of the WCTP and DT Petroleum Agreements which has now been been extended to 2040.

Performance Obligations

As of December 31, 2025 and 2024, the Company had performance bonds and supplemental bonds totaling $151.6 million and $169.4 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 Gulf of America fields.

Once the Tortue Phase 1 SPA Commercial Operations Date was achieved in February 2026, we have a commitment to our buyer under the Tortue Phase 1 SPA, BP Gas Marketing Limited, to deliver our proportionate share of a minimum annual contract quantity of LNG of 127,951,000 MMBtu, which is equivalent to approximately 2.45 million tonnes per annum, subject to certain downward adjustments by the sellers. Under certain circumstances, in the event the annual quantities provided are lower than the minimum annual contract quantity, Kosmos may be obligated to credit or pay a portion of the Contract Price to BP Gas Marketing Limited for the shortfall volumes.

In February 2026, the TEN partnership executed the final Sale and Purchase Agreement to acquire the TEN FPSO from MODEC, Inc. at the end of its current lease in 2027 for a gross purchase price of $205.0 million. We have a commitment to Tullow for our proportionate share of the gross purchase price.

16. Additional Financial Information

Accrued Liabilities

Accrued liabilities consisted of the following:

	December 31, 2025	December 31, 2024
	(In thousands)	
Accrued liabilities:		
Exploration, development and production	$ 57,007	$ 78,163
Revenue payable	69,273	18,909
Current asset retirement obligations	10,481	125
General and administrative expenses	4,916	39,071
Interest	67,830	47,228
Income taxes	16,050	52,262
Taxes other than income	1,305	1,222
Derivatives	125	844
Other	10,622	7,130
	$ 237,609	$ 244,954

Additions to revenue payable during the year ended December 31, 2025 primarily related to timing of a Jubilee lifting and receipt of related proceeds.

Other Expenses, net

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

	Years Ended December 31,		
	2025	2024	2023
		(In thousands)	
Loss on disposal of inventory	$ 3,363	$ 1,835	$ 7,372
(Gain) loss on asset retirement obligation settlements	(6,147)	(3,169)	6,034
Other, net	16,275	19,037	10,250
Other expenses, net	$ 13,491	$ 17,703	$ 23,656

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, 2025, the Company had operations in four geographic reporting segments: Ghana, Equatorial Guinea, Mauritania|Senegal and the Gulf of America. The Company's Chief Operating Decision Maker ("CODM") is the Chief Executive Officer, who makes decisions about allocating resources and assessing performance for the entire company. To assess performance of the reporting segments, the CODM regularly reviews oil and gas revenues, oil and gas production costs, exploration expenses and capital expenditures by reporting segment in deciding how to allocate resources and in assessing performance. 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 reporting segment is presented below:

	Ghana	Equatorial Guinea	Mauritania | Senegal	Gulf of America	Corporate & Other	Eliminations	Total
				(in thousands)			
Years ended December 31, 2025							
Revenues and other income:							
Oil and gas revenue	$ 631,722	$ 165,118	$ 117,197	$ 374,315	$ —	$ —	$ 1,288,352
Gain on sale of assets	—	—	—	2,200	—	—	2,200
Other income, net	1,017	—	—	781	61,897	(62,597)	1,098
Total revenues and other income	632,739	165,118	117,197	377,296	61,897	(62,597)	1,291,650
Costs and expenses:							
Oil and gas production	188,486	132,155	237,577	150,684	—	—	708,902
Exploration expenses	70	2,725	149,139	70,161	1,521	—	223,616
General and administrative	11,365	5,017	9,102	12,524	154,374	(116,262)	76,120
Depletion, depreciation and amortization	177,438	78,828	67,134	231,949	1,425	—	556,774
Impairment of long-lived assets	—	—	—	177,563	—	—	177,563
Interest and other financing costs, net(1)	51,504	(195)	16,460	(5,433)	161,094	—	223,430
Derivatives, net	—	—	—	—	(53,665)	—	(53,665)
Other expenses, net	(32,005)	(10,832)	3,168	(2,665)	2,160	53,665	13,491
Total costs and expenses	396,858	207,698	482,580	634,783	266,909	(62,597)	1,926,231
Income (loss) before income taxes	235,881	(42,580)	(365,383)	(257,487)	(205,012)	—	(634,581)
Income tax expense (benefit)	84,823	(11,860)	—	(48,526)	40,768	—	65,205
Net income (loss)	$ 151,058	$ (30,720)	$ (365,383)	$ (208,961)	$ (245,780)	$ —	$ (699,786)
Consolidated capital expenditures	$ 135,440	$ 11,923	$ 54,719	$ 86,913	$ 3,193	$ —	$ 292,188
As of December 31, 2025							
Property and equipment, net	$ 888,699	$ 424,176	$ 1,907,393	$ 497,587	$ 15,929	$ —	$ 3,733,784
Total assets	$ 3,418,164	$ 2,563,053	$ 3,267,155	$ 3,454,189	$ 27,202,917	$ (35,208,852)	$ 4,696,626

(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	Equatorial Guinea	Mauritania | Senegal	Gulf of America	Corporate & Other	Eliminations	Total
				(in thousands)			
Year ended December 31, 2024							
Revenues and other income:							
Oil and gas revenue	$ 1,044,562	$ 260,675	$ —	$ 370,121	$ —	$ —	$1,675,358
Other income, net	48	—	—	2,895	171,706	(174,445)	204
Total revenues and other income	1,044,610	260,675	—	373,016	171,706	(174,445)	1,675,562
Costs and expenses:							
Oil and gas production	164,385	136,398	93,412	136,319	—	—	530,514
Exploration expenses	3,572	73,009	16,973	21,447	4,906	—	119,907
General and administrative	13,718	6,129	10,974	19,326	212,354	(162,346)	100,155
Depletion, depreciation and amortization	203,501	65,178	950	185,068	2,077	—	456,774
Interest and other financing costs, net(1)	51,302	(2,697)	(146,952)	(12,607)	199,552	—	88,598
Derivatives, net	—	—	—	—	12,099	—	12,099
Other expenses, net	14,894	(4,673)	14,764	4,782	35	(12,099)	17,703
Total costs and expenses	451,372	273,344	(9,879)	354,335	431,023	(174,445)	1,325,750
Income (loss) before income taxes	593,238	(12,669)	9,879	18,681	(259,317)	—	349,812
Income tax expense (benefit)	201,006	(41,217)	—	14,179	(14,007)	—	159,961
Net income (loss)	$ 392,232	$ 28,548	$ 9,879	$ 4,502	$ (245,310)	$ —	$ 189,851
Consolidated capital expenditures	$ 139,130	$ 177,196	$ 324,798	$ 181,160	$ 6,529	$ —	$ 828,813
As of December 31, 2024							
Property and equipment, net	$ 986,693	$ 482,223	$ 2,057,786	$ 901,012	$ 16,507	$ —	$4,444,221
Total assets	$ 3,682,493	$ 2,313,856	$ 3,188,067	$ 4,094,116	$ 25,867,010	$ (33,836,554)	$5,308,988

(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	Equatorial Guinea	Mauritania | Senegal	Gulf of America	Corporate & Other	Eliminations	Total
				(in thousands)			
Year 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 (benefit)	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.

	Years Ended December 31,		
	2025	2024	2023
		(In thousands)	
Consolidated capital expenditures:			
Consolidated Statements of Cash Flows - Investing activities:			
Oil and gas assets	$ 314,408	$ 933,659	$ 932,603
Adjustments:			
Changes in capital accruals	(21,040)	13,392	6,732
Exploration expense, excluding unsuccessful well costs and leasehold impairments(1)	21,125	45,418	40,070
Capitalized interest	(16,492)	(168,715)	(138,738)
Other	(5,813)	5,059	9,332
Total consolidated capital expenditures	$ 292,188	$ 828,813	$ 849,999

(1) Costs related to unsuccessful exploratory wells and leaseholds that are subsequently written off to Exploration expense 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, 2025, 2024 and 2023. 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 petroleum engineers to ensure the integrity, accuracy and timeliness of data furnished to independent petroleum 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 Gulf of America.

	Ghana	Equatorial Guinea	Mauritania | Senegal	Gulf of America	Total Oil	Ghana	Equatorial Guinea	Mauritania | Senegal	Gulf of America	Total Gas	Kosmos Total
	Oil, Condensate, NGLs (MMBbls)(3)					Natural Gas (Bcf)(5)					(MMBoe)
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
Purchases 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
Extensions and discoveries	—	—	—	1	1	—	—	—	—	—	1
Production	(13)	(3)	—	(5)	(21)	(15)	(1)	—	(4)	(20)	(24)
Revision in estimate(2)	(4)	(3)	—	4	(3)	(5)	(4)	4	2	(3)	(4)
Purchases of minerals-in-place	—	—	—	—	—	—	—	—	—	—	—
Sales of minerals-in-place	—	—	—	—	—	—	—	—	—	—	—
Net proved developed and undeveloped reserves at December 31, 2024(1)	76	18	7	21	122	115	11	632	16	774	251
Extensions and discoveries	—	—	—	—	—	—	—	—	—	—	—
Production	(9)	(3)	—	(6)	(18)	(15)	(1)	(17)	(4)	(37)	(24)
Revision in estimate(2)	18	(3)	—	2	17	36	(4)	1	—	33	23
Purchase of minerals-in-place	—	—	—	—	—	—	—	—	—	—	—
Sales of minerals-in-place	—	—	—	—	—	—	—	—	—	—	—
Net proved developed and undeveloped reserves at December 31, 2025(1)	85	12	7	17	120	136	6	616	12	770	249
Proved developed reserves(1)											
December 31, 2022	43	20	—	21	84	40	16	—	17	73	96
December 31, 2023	46	19	—	15	81	79	16	—	12	106	99
December 31, 2024	39	17	—	18	74	75	11	—	11	97	90
December 31, 2025	32	12	4	15	63	76	6	358	9	449	138
Proved undeveloped reserves(1)(4)											
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
December 31, 2024	37	1	7	3	48	40	—	632	5	677	161
December 31, 2025	53	—	3	2	57	60	—	258	2	321	111

(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 2025 are related to:

- In Ghana, Jubilee had a positive revision of 17.9 MMBbl and 13.7 Bcf based on the license extension and update to the Petroleum Agreement amendments, which facilitate additional field development, as well as a positive revision of 22.8 Bcf related to the updated GSA. The net production in Jubilee for the year ended December 31, 2025 was 8.1 MMBbl and 13.9 Bcf. TEN had a negative revision of 0.4 MMBbl and 0.7 Bcf based on field performance, in addition to the net TEN production of 1.1 MMBbl and 0.7 Bcf. Overall, for the year ended December 31, 2025, Jubilee had an increase in reserves of 9.8 MMBbl and 22.6 Bcf and TEN had a decrease in reserves of 1.5 MMBbl and 1.5 Bcf. We note that the decrease in commodity prices did not result in revisions of estimates.
- In Equatorial Guinea, we had a reserves decrease of 1.3 MMBbl from the loss of uneconomic PUD volume and 1.1 MMBbl and 0.2 Bcf due to performance in Ceiba, partially offset by reserves increase due to performance in Okume of 1.2 MMBbl and 0.7 Bcf. The commodity price effect resulted in a loss of 2.4 MMBbl and 3.3 Bcf in Ceiba and 0.4 MMBbl and 0.6 Bcf in Okume. The net production for the year ended December 31, 2025 was 0.9 MMBbl and 0.4 Bcf in Ceiba and 1.7 MMBbl and 0.7 Bcf in Okume. Overall, Equatorial Guinea had a decrease in reserves of 6.6 MMBbl and 4.5 Bcf.
- In Mauritania and Senegal, we had a positive revision of 52.8 Bcf due to increase in the annual production capacity from 2.45 to 2.7 MTPA for the duration of the field life based on realized production volumes and operator plan Greater Tortue Ahmeyim Phase 1 project. This increase is offset by a a negative revision of 51.3 Bcf due to the delay in initial production and ramp up at the beginning of SPA term. The net production for the year ended December 31, 2025 was 0.3 MMBbl and 17.2 Bcf. Overall, there was a decrease in reserves in Mauritania and Senegal of 0.2 MMBbl and 15.8 Bcf. We note that the decrease in commodity prices did not result in revisions of estimates.
- In the Gulf of America, we had a positive reserves revision of 6.2 MMBbl and 1.1 Bcf primarily driven by performance in Kodiak, Tornado, and Odd Job, partially offset by a negative reserves revision in Winterfell due to performance of 2.4 MMBbl and 0.5 Bcf. Change in the plan of development in Marmalard resulted in a negative revision of 1.1 MMBbl and 1.7 Bcf. The net production for the year ended December 31, 2025 was 5.8 MMBbl and 3.7 Bcf. Overall, for the year ended December 31, 2025, the Gulf of America had a reserves decrease of 3.2 MMBbl and 4.9 Bcf. We note that the revision of reserves related to the commodity prices decrease was negligible.

The revisions in estimates in 2024 are related to:

- In Ghana, Jubilee had a negative revision of 5.4 MMBbl and 12.7 Bcf due to field performance primarily related to the J-69 & J-68 wells, partially offset by the positive revision of 4.4 MMBbl and 5.7 Bcf due to drilling of two wells that had no prior proved recognition, in addition to Jubilee net production of 11.7 MMBbl and 13.7 Bcf. TEN had a negative revision of 2.6 MMBbl driven by removal of future development opportunities from the TEN Fields and a small positive revision of 0.9 Bcf of gas due to extension in the field life, in addition to the net TEN production of 1.3 MMBbl and 0.9 Bcf. Overall, for the year ended December 31, 2024, Jubilee had a decrease in reserves of 12.7 MMBbl and 20.7 Bcf and TEN had a decrease in reserves of 4.0 MMBbl. We note that the decrease in commodity prices did not result in revisions of estimates.
- In Equatorial Guinea, we had a reserves decrease of 2.5 MMBbl and 3.3 Bcf primarily from the loss of uneconomic PUD volume in Okume with an additional decrease from net production of 1.3 MMBbl and 0.6 Bcf in Ceiba and 1.9 MMBbl and 0.9 Bcf in Okume. Overall, Equatorial Guinea had a decrease in reserves of 5.7 MMBbl and 4.7 Bcf. We note that the decrease in commodity prices did not result in revisions of estimates.
- In Mauritania and Senegal, we had a positive revision of 0.2 MMBbl and 4.2 Bcf due change in the calculated net reserves amount based on the updated economic parameters as part of the petroleum contract calculations of the Greater Tortue Ahmeyim Phase 1 project. We note that the decrease in commodity prices did not result in revisions of estimates.
- In the Gulf of America, we had a positive reserves revision of 3.2 MMBbl and 2.1 Bcf due to Winterfell performance and an updated plan of development for Marmalard, in addition to an extension of 1.2 MMBbl and 0.2 Bcf based on the results of the drilled Winterfell-3 well, offset by the net production of 5.0 MMBbl and 3.7 Bcf. Overall, for the year ended December 31, 2024, the Gulf of America had a reserves decrease of 0.6 MMBbl and 1.5 Bcf. We note that the decrease in commodity prices did not result in revisions of estimates.

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 Gulf of America, 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 Gulf of America had a reserves decrease of 6.8 MMBbl and 6.2 Bcf.

(3) 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.

(4) The revisions in estimates in 2025 are related to:

- In Ghana, we converted 14.4 MMBbl and 14.0 Bcf of proved undeveloped reserves to proved developed with the drilling of two wells in Jubilee at a cost of approximately $61.0 million. License extension, an update to the Petroleum Agreement amendments, facilitating additional field development, and an update to the GSA resulted in a positive revision of 29.8 MMBbl and 34.2 Bcf.
- In Equatorial Guinea, we had a negative revision of 1.3 MMBbl in Ceiba due to loss of uneconomic PUD.

- In Mauritania and Senegal, we spent approximately $49.1 million related to the completion of the first phase of the Greater Tortue Ahmeyim development. With the start up of production of three previously drilled wells in the Greater Tortue Ahmeyim Phase 1 project, 4.3 MMBbl and 357.8 Bcf of proved undeveloped reserves were converted to proved developed.
- In the Gulf of America, we converted 0.2 MMBbl and 0.4 Bcf at a cost of approximately $6.2 million by drilling a sidetrack in Marmalard. In addition, we had a negative reserves revision of 1.1 MMBbl and 1.7 Bcf in Marmalard due to the change in the plan of development, and a reserves revision of 0.7 MMBbl and -0.7 Bcf, driven primarily by the addition of a planned sidetrack in Winterfell.

The changes in proved undeveloped reserves in 2024 are related to:

- In Ghana, we converted 13.9 MMBbl and 14.7 Bcf of proved undeveloped reserves to proved developed with the drilling of three wells in Jubilee at a cost of approximately $42.6 million. We also drilled two wells at a cost of $62.7 million that did not convert proved developed reserves as the wells did not have any proved recognition in the prior year. Optimization of future well forecasts in Jubilee resulted in a positive revision of 7.4 MMBbl, offset by the negative adjustment of the sales gas forecast of 1.8 Bcf in Jubilee and a negative revision of 3.2 MMBbl due to removal of additional planned development at TEN.
- In Equatorial Guinea, we converted 1.8 MMBbl of proved undeveloped reserves to proved developed reserves at a cost of $142.6 million by drilling of two wells. We also had a negative revision of 2.7 MMBbl in Okume due to loss of uneconomic PUD, partially offset by a positive revision of 1.3 MMBbl in Ceiba with an addition of two undeveloped wells.
- In Mauritania and Senegal, we spent approximately $310.9 million progressing the Greater Tortue Ahmeyim Phase 1 project. We had a positive revision of 0.2 MMBbl and 4.2 Bcf due to the change in the calculated net reserves amount based on the updated economic parameters as part of the petroleum contract calculations of the Greater Tortue Ahmeyim Phase 1 project.
- In the Gulf of America, we converted 1.2 MMBbl and 1.6 Bcf at a cost of approximately $42.6 million with the installation of the subsea pump in Odd Job. In addition, we converted 2.7 MMBbl and 1.0 Bcf with the completion of two wells in the Winterfell Field at a cost of $78.9 million. We also had a positive revision of 0.8 MMBbl and 1.6 Bcf due to the addition of two undeveloped wells in Marmalard.

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 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.
- In the Gulf of America, 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.

(5) These reserves include the estimated quantity of gas to be exported as LNG from the Greater Tortue Ahmeyim Phase 1 project, 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 Phase 1 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, 18.5 Bcf and 19.9 Bcf for 2025, 2024 and 2023, 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 50.2 Bcf, 55.8 Bcf and 52.3 Bcf in 2025, 2024 and 2023, respectively. For the Gulf of America, total proved natural gas reserves include fuel gas of approximately 0.6 Bcf for 2025, 1.9 Bcf for 2024 and 1.1 Bcf for 2023.

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 2025. 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	Gulf of America	Other	Kosmos Total
			(In millions)			
As of December 31, 2025						
Unproved properties	$ —	$ 14	$ 1	$ 182	$ 13	$ 210
Proved properties	3,976	788	1,972	1,564	$ 2	8,302
	3,976	802	1,973	1,746	15	8,512
Accumulated depletion	(3,088)	(378)	(66)	(1,249)	—	(4,781)
Net capitalized costs	$ 888	$ 424	$ 1,907	$ 497	$ 15	$ 3,731
As of December 31, 2024						
Unproved properties	$ —	$ 33	$ 135	$ 205	$ 14	$ 387
Proved properties	3,911	760	1,923	1,749	(1)	8,342
	3,911	793	2,058	1,954	13	8,729
Accumulated depletion	(2,924)	(311)	—	(1,053)	—	(4,288)
Net capitalized costs	$ 987	$ 482	$ 2,058	$ 901	$ 13	$ 4,441

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	Gulf of America	Other	Kosmos Total
			(In millions)			
Year ended December 31, 2025						
Property acquisition:						
Unproved	$ —	$ —	$ —	$ —	$ —	$ —
Proved	—	—	2	—	—	2
Exploration	—	3	6	73	2	84
Development	135	9	48	18	—	210
Total costs incurred(1)	$ 135	$ 12	$ 56	$ 91	$ 2	$ 296
Year ended December 31, 2024						
Property acquisition:						
Unproved	$ —	$ —	$ —	$ 5	$ —	$ 5
Proved	—	—	—	—	—	—
Exploration	—	36	27	45	5	113
Development	145	150	460	152	—	907
Total costs incurred	$ 145	$ 186	$ 487	$ 202	$ 5	$ 1,025
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

(1) Excludes $96.6 million reduction of capitalized asset retirement costs primarily related to the license extension of the WCTP and DT Petroleum Agreements in Ghana in December 2025 and changes in estimated timing of work.

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 2025. 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	Gulf of America	Total
			(In millions)		
At December 31, 2025					
Future cash inflows	$ 6,313	$ 793	$ 4,492	$ 1,044	$ 12,642
Future production costs	(1,379)	(480)	(2,876)	(395)	(5,130)
Future development and abandonment costs	(1,832)	(362)	(696)	(234)	(3,124)
Future tax expenses	(998)	(63)	—	(13)	(1,074)
Future net cash flows	2,104	(112)	920	402	3,314
10% annual discount for estimated timing of cash flows	(616)	106	(893)	(21)	(1,424)
Standardized measure of discounted future net cash flows	$ 1,488	$ (6)	$ 27	$ 381	$ 1,890
At December 31, 2024					
Future cash inflows	$ 6,592	$ 1,426	$ 5,305	$ 1,415	$ 14,738
Future production costs	(1,275)	(744)	(3,155)	(453)	(5,627)
Future development and abandonment costs	(990)	(434)	(1,104)	(239)	(2,767)
Future tax expenses	(1,399)	(144)	—	(22)	(1,565)
Future net cash flows	2,928	104	1,046	701	4,779
10% annual discount for estimated timing of cash flows	(722)	126	(818)	(63)	(1,477)
Standardized measure of discounted future net cash flows	$ 2,206	$ 230	$ 228	$ 638	$ 3,302
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

Changes in the Standardized Measure for Discounted Cash Flows

	Ghana	Equatorial Guinea	Mauritania | Senegal	Gulf of America	Total
			(In millions)		
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
Purchase of minerals in place	—	—	—	—	—
Sales of minerals in place	—	—	—	—	—
Sales and transfers 2024	(880)	(124)	—	(234)	(1,238)
Extensions and discoveries	—	—	—	51	51
Net changes in prices and costs	(205)	(122)	(209)	(109)	(645)
Previously estimated development costs incurred during the period	139	141	308	70	658
Net changes in development costs	56	(65)	(643)	(26)	(678)
Revisions of previous quantity estimates	(113)	(75)	3	132	(53)
Net changes in tax expenses	81	70	2	24	177
Accretion of discount	406	55	—	65	526
Changes in timing and other	(51)	(2)	(14)	(49)	(116)
Balance at December 31, 2024	$ 2,206	$ 230	$ 228	$ 638	$ 3,302
Purchase of minerals in place	—	—	—	—	—
Sales of minerals in place	—	—	—	—	—
Sales and transfers 2025	(444)	(33)	120	(224)	(581)
Extensions and discoveries	—	—	—	—	—
Net changes in prices and costs	(757)	(218)	(812)	(161)	(1,948)
Previously estimated development costs incurred during the period	135	10	49	14	208
Net changes in development costs	(583)	(6)	395	(18)	(212)
Revisions of previous quantity estimates	380	(80)	3	85	388
Net changes in tax expenses	205	38	—	1	244
Accretion of discount	320	34	23	65	442
Changes in timing and other	26	19	21	(19)	47
Balance at December 31, 2025	$ 1,488	$ (6)	$ 27	$ 381	$ 1,890

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, 2025, 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, 2025 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

Rule 10b5-1 and Non Rule 10b5-1 Trading Arrangements

During the three months ended December 31, 2025, none of our officers or directors adopted or terminated a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as each term is defined in Item 408(a) of Regulation S-K.

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 2026 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2025.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2026 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2025.

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 2026 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2025.

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

The information required by this item is incorporated herein by reference to the 2026 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2025.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the 2026 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2025.

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 2025, 2024 and 2023 (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, 2025	December 31, 2024
Assets		
Current assets:		
Cash and cash equivalents	$ 345	$ 39
Prepaid expenses and other	1,125	707
Derivatives	8,162	—
Total current assets	9,632	746
Other assets:		
Restricted cash	305	305
Investment in subsidiaries at equity	2,486,929	3,262,312
Derivatives	543	—
Deferred tax assets	—	22,919
Total assets	$ 2,497,409	$ 3,286,282
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable	$ 2	$ 23
Accounts payable to subsidiaries	183,282	175,922
Accrued liabilities	32,017	34,845
Current maturities of long-term debt	100,000	—
Derivatives - related party	8,162	—
Total current liabilities	323,463	210,790
Long-term liabilities:		
Long-term debt, net	1,630,074	1,875,068
Derivatives - related party	543	—
Deferred tax liabilities	14,739	—
Total long-term liabilities	1,645,356	1,875,068
Shareholders' equity:		
Preference shares, $0.01 par value; 200,000,000 authorized shares; zero issued at December 31, 2025 and December 31, 2024	—	—
Common stock, $0.01 par value; 2,000,000,000 authorized shares; 522,590,223 and 516,158,749 issued at December 31, 2025 and December 31, 2024, respectively	5,226	5,162
Additional paid-in capital	2,542,627	2,514,739
Accumulated deficit	(1,782,256)	(1,082,470)
Treasury stock, at cost, 44,263,269 shares at December 31, 2025 and 2024, respectively	(237,007)	(237,007)
Total shareholders' equity	528,590	1,200,424
Total liabilities and shareholders' equity	$ 2,497,409	$ 3,286,282

KOSMOS ENERGY LTD.

CONDENSED PARENT COMPANY STATEMENTS OF OPERATIONS

(In thousands)

	Years Ended December 31,		
	2025	2024	2023
Revenues and other income:			
Oil and gas revenue	$ —	$ —	$ —
Total revenues and other income	—	—	—
Costs and expenses:			
General and administrative	36,927	49,279	52,279
General and administrative recoveries—related party	2,274	1,326	(6,048)
Interest and other financing costs, net	134,943	136,950	122,773
Derivatives, net—related party	8,705	—	—
Derivatives, net	(8,705)	—	—
Other expenses, net	(43)	65	131
Equity in (earnings) of subsidiaries	488,119	(365,362)	(370,729)
Total costs and expenses	662,220	(177,742)	(201,594)
Income before income taxes	(662,220)	177,742	201,594
Income tax expense (benefit)	37,566	(12,109)	(11,926)
Net income (loss)	$ (699,786)	$ 189,851	$ 213,520

KOSMOS ENERGY LTD.

CONDENSED PARENT COMPANY STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31,		
	2025	2024	2023
Operating activities			
Net income (loss)	$ (699,786)	$ 189,851	$ 213,520
Adjustments to reconcile net income to net cash (used in) operating activities:			
Equity in (earnings) of subsidiaries	488,119	(365,362)	(370,729)
Equity-based compensation	27,953	37,951	42,693
Depreciation and amortization	6,147	7,497	6,588
Deferred income taxes	37,659	(10,869)	(11,589)
Other income—related party	8,705	—	413
Change in fair value of derivatives	(8,705)	—	—
Debt modifications and extinguishments	195	3,192	—
Changes in assets and liabilities:			
Decrease in receivables	(1)	6	87
(Increase) decrease in prepaid expenses and other	(418)	45	299
Decrease due to/from related party	6,802	22,501	37,765
Increase (decrease) in accounts payable and accrued liabilities	(3,542)	6,694	60
Net cash (used in) operating activities	(136,872)	(108,494)	(80,893)
Investing activities			
Investment in subsidiaries	287,264	(213,294)	90,858
Net cash provided by (used in) investing activities	287,264	(213,294)	90,858
Financing activities			
Net proceeds from issuance of senior notes	—	885,285	—
Repurchase and redemption of senior notes	(150,000)	(499,515)	—
Purchase of capped call transactions	—	(49,800)	
Dividends	—	—	(166)
Other financing costs	(86)	(14,418)	(11,810)
Net cash provided by (used in) financing activities	(150,086)	321,552	(11,976)
Net increase (decrease) in cash and cash equivalents	306	(236)	(2,011)
Cash, cash equivalents and restricted cash at beginning of period	344	580	2,591
Cash, cash equivalents and restricted cash at end of period	$ 650	$ 344	$ 580

Schedule II

Kosmos Energy Ltd.

Valuation and Qualifying Accounts

For the Years Ended December 31, 2025, 2024 and 2023

		Additions			
Description	**Balance January 1,**	**Charged to Costs and Expenses**	**Charged To Other Accounts**	**Deductions From Reserves**	**Balance December 31,**
2025					
Allowance for credit losses	$ 13,568	$ 3,737	$ (59)	$ —	$ 17,246
Allowance for deferred tax assets	$ 405,831	$ 125,865	$ —	$ —	$ 531,696
2024					
Allowance for credit losses	$ 9,847	$ 3,721	$ —	$ —	$ 13,568
Allowance for deferred tax assets	$ 333,651	$ 72,180	$ —	$ —	$ 405,831
2023					
Allowance for credit losses	$ 7,011	$ 2,842	$ (6)	$ —	$ 9,847
Allowance for deferred tax assets	$ 312,727	$ 20,924	$ —	$ —	$ 333,651

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 136 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: March 2, 2026

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)	March 2, 2026
/s/ NEAL D. SHAH Neal D. Shah	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	March 2, 2026
/s/ RONALD W. GLASS Ronald W. Glass	Vice President and Chief Accounting Officer (Principal Accounting Officer)	March 2, 2026
/s/ ROY A. FRANKLIN Roy A. Franklin	Director	March 2, 2026
/s/ DEANNA L. GOODWIN Deanna L. Goodwin	Director	March 2, 2026
/s/ ADEBAYO O. OGUNLESI Adebayo O. Ogunlesi	Director	March 2, 2026
/s/ STEVEN M. STERIN Steven M. Sterin	Director	March 2, 2026
/s/ MARIA M. HANSSEN Maria M. Hanssen	Director	March 2, 2026
/s/ SIR JOHN GRANT Sir John Grant	Director	March 2, 2026
/s/ J. MIKE STICE J. Mike Stice	Director	March 2, 2026

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).
	Equatorial Guinea
10.15	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).
10.16	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).
10.17	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).
10.18	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).
10.19	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).
10.20	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 (filed as Exhibit 10.21 to the Company’s Annual Report on Form 10-K as of the year ended December 31, 2023, and incorporated herein by reference).
10.21	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 (filed as Exhibit 10.22 to the Company’s Annual Report on Form 10-K as of the year ended December 31, 2023, and incorporated herein by reference).
10.22	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).
10.23	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).

Exhibit Number	Description of Document
10.24	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).
10.25	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
10.26††	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
10.27	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).
10.28	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).
10.29	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 99.1 to the Company’s Current Report on Form 8-K filed August 7, 2018 (File No. 001-35167), and incorporated herein by reference).
10.30	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).
10.31	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).
10.32	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).
10.33	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).
10.34	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).

Exhibit Number	Description of Document
10.35	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).
10.36	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).
10.37	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 herein by reference).
10.38	Indenture dated March 8, 2024 among the Company, the guarantors named therein, and Wilmington Trust, National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K filed March 8, 2024 (File No. 001-35167), and incorporated herein by reference).
10.39	Amended and Restated Facility Agreement, effective April 25, 2024, 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 Energy Equatorial Guinea, Inc., Kosmos Energy International Petroleum, Inc., ABSA Bank Limited, ING Belgium SA/NV, Natixis, N.B.S.A Limited, The Standard Bank of South Africa Limited, Isle of Man Branch, Standard Chartered Bank, ABSA Bank (Mauritius) Limited and Deutsche Bank AG, Amsterdam Branch (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2024, and incorporated herein by reference).
10.40	Indenture dated September 24, 2024 among the Company, the guarantors named therein, Wilmington Trust, National Association, as trustee, paying agent, transfer agent and registrar, and Circumference Services S.À.r.l., as Luxembourg paying agent, listing agent, registrar and transfer agent (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K filed September 24, 2024 (File No. 001-35167), and incorporated herein by reference).
10.41† †	Senior Secured Term Loan Credit Agreement, dated September 24, 2025, among Kosmos Energy Gulf of Mexico Operations, LLC, as Borrower, the other Loan Parties party thereto from time to time, Shell Trading (US) Company, as Lender, and Ankura Trust Company, LLC, as the Collateral Agent and Administrative Agent (filed as Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2025, and incorporated herein by reference).
	Management Contracts/Compensatory Plans or Arrangements
10.42†	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).
10.43†	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).
10.44†	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).
10.45†	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).
10.46†	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).
10.47†	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).

Exhibit Number	Description of Document
10.48†	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).
10.49†	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).
10.50†	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).
10.51†	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).
10.52†	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).
10.53†	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).
10.54†	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).
10.55†	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).
10.56†	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).
10.57†	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).
10.58†	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).
10.59†	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).
10.60†	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).
10.61†	Exit Agreement between Kosmos Energy, LLC and Jason E. Doughty dated July 8, 2024 (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2024, and incorporated herein by reference).
10.62†	Offer Letter, dated July 6, 2024, between Kosmos Energy, LLC and Josh R. Marion (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2025, and incorporated herein by reference).
10.63†	Transition Agreement between Kosmos Energy, LLC and Christopher J. Ball dated August 21, 2025 (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2025, and incorporated herein by reference).
10.64†	Advisory Agreement between Kosmos Energy, LLC and Christopher J. Ball dated August 21, 2025 (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2025, and incorporated herein by reference).
	Anadarko WCTP Acquisition
10.65	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
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).
19.0	Kosmos Dealing Policy (filed as Exhibit 19.0 to the Company's Annual Report on Form 10-K for the year ended December 31, 2024, 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.

Exhibit Number	Description of Document
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 (filed as Exhibit 97.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2023, and incorporated herein by reference).
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.

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Corporate Leadership

BOARD OF DIRECTORS

ANDREW G. INGLIS

Chairman of the Board of Directors
Chief Executive Officer

ROY A. FRANKLIN

Former Chairman, Wood plc

DEANNA L. GOODWIN

Director, Arcadis NV
Director, Oceaneering International, Inc.

SIR JOHN GRANT

Retired Vice President, International Government Relations, Anadarko Petroleum Corporation

MARIA MORÆUS HANSSEN

Director, SLB
Director, Scatec ASA

ADEBAYO O. OGUNLESI

Chairman and Chief Executive Officer, Global Infrastructure Partners

STEVEN M. STERIN

Director, Qnity Electronics, Inc.

J. MICHAEL STICE

Director, Marathon Petroleum Corporation
Director, MPLX GP LLC

SENIOR LEADERSHIP

ANDREW G. INGLIS

Chairman of the Board of Directors
Chief Executive Officer

NEAL D. SHAH

Senior Vice President
Chief Financial Officer

JOSH R. MARION

Senior Vice President
General Counsel

RONALD GLASS

Vice President
Chief Accounting Officer

DIVERSITY IN THE BOARD OF DIRECTORS AND EXECUTIVE MANAGEMENT OF KOSMOS ENERGY

Pursuant to UKLR 14.3.30R(1) of the UK Financial Conduct Authority (FCA) Listing Rules, the Board of Directors of Kosmos Energy confirms that, as of December 31, 2025, the Company has partially met the targets set out in this provision because at least one member of the Board of Directors was from a minority ethnic background. The Company did not meet the targets in relation to the requirements that at least 40% of the members of the Board were women and that at least one of the named executive positions should be held by a woman. The Company recognizes the importance of diversity and its long-term goal is to further improve diversity on the Board. This is taken into account primarily in the context of succession planning for the Board.

Since December 31, 2025, there have been no changes in the composition of the Board of Directors that would affect the company's ability to achieve any of the objectives mentioned above.

Data on gender and ethnicity was collected directly from Board members and members of the executive management who were asked to indicate their gender and their ethnicity using the categories in the tables below.

In accordance with UKLR 14.3.30R(2) of the UK FCA Listing Rules, the following tables contain data on the gender and ethnicity of the members of the Board of Directors and executive management of the company as of December 31, 2025.

	Number of Board Members	Percentage of the Board	Number of Senior Positions on the Board (CEO, CFO, SID and Chair)	Number in Executive Management	Percentage of Executive Management
GENDER					
Men	6	75%	2	3	100%
Women	2	25%	0	0	0%
Not specified/ Prefer not to say	—	—	—	—	—

	Number of Board Members	Percentage of the Board	Number of Senior Positions on the Board (CEO, CFO, SID and Chair)	Number in Executive Management	Percentage of Executive Management
ETHNICITY					
White British or other White (including minority-white groups)	7	87.5%	1	2	67%
Mixed/Multiple Ethnic Groups	—	—	—	—	—
Asian/Asian British	—	—	—	1	33%
Black/African/ Caribbean/ Black British	1	12.5%	1	—	—
Other ethnic group	—	—	—	—	—
Not specified/ Prefer not to say	—	—	—	—	—

Within the meaning of UKLR 14.3.30R, the Company only has two senior positions on the Board, being a combined CEO and Chair role and a SID. The CFO forms part of Executive Management but does not sit on the Board. The individual holding the CEO / Chair role is also a member of Executive Management: data pertaining to these individuals has not been included when reporting on Executive Management, so as to avoid double counting.

Corporate Information

PRIMARY OFFICE

Kosmos Energy Ltd.
8176 Park Lane
Suite 500
Dallas, TX 75231

REGISTERED OFFICE

Kosmos Energy Ltd.
Corporation Trust Center
1209 Orange Street
Wilmington, DE 19801

WEBSITE

www.kosmosenergy.com

STOCK EXCHANGE LISTING

New York Stock Exchange
London Stock Exchange
Symbol: KOS

ANNUAL MEETING

May 28, 2026
8:00 a.m. Central Daylight Time
Virtual-Only Format:
www.virtualshareholdermeeting.com/KOS2026

FORM 10-K

Copies of the Company's 10-K are available on our website at www.kosmosenergy.com

AUDITORS

Ernst & Young
Dallas, TX

SHAREHOLDER SERVICES

Computershare
250 Royall Street
Canton, MA 02021
1-800-962-4284 (Toll-Free)
1-781-575-3120 (International)

INVESTOR RELATIONS

Additional corporate information is available on our website at www.kosmosenergy.com

CLIMATE-RELATED DISCLOSURE

The climate-related financial disclosures required under UKLR 14.3.24R are included in our 2025 Sustainability Report. We have considered our obligations in respect of climate-related disclosures under the UK Financial Conduct Authority's Listing Rules and confirm that we have made disclosures consistent with the relevant Listing Rules and the Taskforce for Climate-related Financial Disclosures (TCFD) Recommendations and Recommended Disclosures. We value our climate reporting and believe that our stakeholders are, at present, better served by including these disclosures in a complete and distinct report which incorporates all relevant information on our business and the climate.

FORWARD-LOOKING STATEMENTS

This annual report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this report that address activities, events or developments that Kosmos Energy Ltd. ("Kosmos" or the "Company") expects, believes or anticipates will or may occur in the future are forward-looking statements. Without limiting the generality of the foregoing, forward-looking statements contained in this report specifically include the expectations of management regarding plans, strategies, objectives, anticipated financial and operating results of the Company, including as to estimated oil and gas in place and recoverability of the oil and gas, estimated reserves and drilling locations, capital expenditures, typical well results and well profiles and production and operating expenses guidance included in the report. The Company's estimates and forward-looking statements are mainly based on its current expectations and estimates of future events and trends, which affect or may affect its businesses and operations. Although the Company believes 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 the Company. When used in this report, the words "anticipate," "believe," "intend," "expect," "plan," "will" or other similar words are intended to identify forward-looking statements. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. Further information on such assumptions, risks and uncertainties is available in the Company's Securities and Exchange Commission ("SEC") filings. The Company's SEC filings are available on the Company's website at www.kosmosenergy.com. Kosmos undertakes no obligation and does not intend to update or correct these forward-looking statements to reflect events or circumstances occurring after the date of this report, whether as a result of new information, future events or otherwise, except as required by applicable law. You are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date of this report. All forward-looking statements are qualified in their entirety by this cautionary statement.

CAUTIONARY STATEMENTS REGARDING OIL AND GAS QUANTITIES

The SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves that meet the SEC's definitions for such terms, and price and cost sensitivities for such reserves, and prohibits disclosure of resources that do not constitute such reserves. The Company uses terms in this report, such as "discovered resources," "potential," "significant resource upside," "resource," "net resources," "recoverable resources," "discovered resource," "world-class discovered resource," "significant defined resource," "gross unrisked resource potential," "defined growth resources," "recovery potential" and similar terms or other descriptions of volumes of reserves potentially recoverable that the SEC's guidelines strictly prohibit the Company from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved, probable and possible reserves and accordingly are subject to substantially greater risk of being actually realized. Investors are urged to consider closely the disclosures and risk factors in the Company's SEC filings, available on the Company's website at www.kosmosenergy.com. Potential drilling locations and resource potential estimates have not been risked by the Company. Actual locations drilled and quantities that may be ultimately recovered from the Company's interest may differ substantially from these estimates. There is no commitment by the Company to drill all of the drilling locations that have been attributed these quantities. Factors affecting ultimate recovery include the scope of the Company's ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability of drilling and completion services and equipment, drilling results, agreement terminations, regulatory approval and actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of reserves and resource potential may change significantly as development of the Company's oil and gas assets provides additional data.

NON-GAAP FINANCIAL MEASURES

EBITDAX and net debt are supplemental non-GAAP financial measures used by management and external users of the Company's consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. The Company defines EBITDAX as 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) debt modifications and extinguishments, (ix) doubtful accounts expense and (x) similar other material items which management believes affect the comparability of operating results. The Company defines net debt as total long-term debt less cash and cash equivalents and total restricted cash.

We believe that EBITDAX, net debt and other similar measures are useful to investors because they are frequently used by securities analysts, investors and other interested parties in the evaluation of companies in the oil and gas sector and will provide investors with a useful tool for assessing the comparability between periods, among securities analysts, as well as company by company. EBITDAX and net debt as presented by us may not be comparable to similarly titled measures of other companies.

KOSMOS ENERGY®