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, 2019

☐ **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 is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the voting and non-voting common stock held by non-affiliates, based on the per-share closing price of the registrant's common stock as of the last business day of the registrant's most recently completed second fiscal quarter was $2,220,129,484.

The number of the registrant's Common Stock outstanding as of February 14, 2020 was 405,098,215.

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, 2019.

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

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Unless otherwise stated in this report, references to "Kosmos," "we," "us" or "the company" refer to Kosmos Energy Ltd. and its subsidiaries. On December 28, 2018, we changed our jurisdiction of incorporation from Bermuda to the State of Delaware, which we refer to herein as the Redomestication. All references to "Kosmos," "we," "us" or "the company" on or before December 28, 2018 refer to Kosmos Energy Ltd., an exempted company incorporated pursuant to the laws of Bermuda, and its subsidiaries. All such references after December 28, 2018 refer to Kosmos Energy Ltd., a Delaware corporation, and its subsidiaries. In addition, all references to "common stock" on or before December 28, 2018 refer to the common shares of Kosmos Energy Ltd. prior to the Redomestication, and all such references after December 28, 2018 refer to the common stock of Kosmos Energy Ltd. after the Redomestication. For additional detail, please see "Item 1. Business—Corporate Information."

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 3.

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.
“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.
"DGE"	Deep Gulf Energy (together with its subsidiaries).
"DST"	Drill stem test.
“Dry hole” or "Unsuccessful well"	A well that has not encountered a hydrocarbon bearing reservoir expected to produce in commercial quantities.
"DT"	Deepwater Tano.
“EBITDAX”	Net income (loss) plus (i) exploration expense, (ii) depletion, depreciation and amortization expense, (iii) equity-based compensation expense, (iv) unrealized (gain) loss on commodity derivatives (realized losses are deducted and realized gains are added back), (v) (gain) loss on sale of oil and gas properties, (vi) interest (income) expense, (vii) income taxes, (viii) loss on extinguishment of debt, (ix) doubtful accounts expense and (x) similar other material items which management believes affect the comparability of operating results. The Facility EBITDAX definition includes 50% of the EBITDAX adjustments of Kosmos-Trident International Petroleum Inc for the period it was an equity method investment and includes Last Twelve Months ("LTM") EBITDAX for any acquisitions and excludes LTM EBITDAX for any divestitures.
"ESG"	Environmental, social, and governance.
"ESP"	Electric submersible pump.
“E&P”	Exploration and production.

“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.
"Galp"	Galp Energia Sao Tome E Principe, Unipessoal, LDA.
"GEPetrol"	Guinea Equatorial De Petroleos.
"GHG"	Greenhouse gas.
"GJFFDP"	Greater Jubilee Full Field Development Plan.
"GNPC"	Ghana National Petroleum Corporation.
“Greater Tortue Ahmeyim”	Ahmeyim and Guembeul discoveries.
"GTA UUOA"	Unitization and Unit Operating Agreement covering the Greater Tortue Ahmeyim Unit.
"Hess"	Hess Corporation.
"HLS"	Heavy Louisiana Sweet.
"H&M"	Hull and Machinery insurance.
"Jubilee UUOA"	Unitization and Unit Operating Agreement covering the Jubilee Unit.
"KBSL"	Kosmos BP Senegal Limited.
"KTEGI"	Kosmos-Trident Equatorial Guinea Inc.
"KTIPI"	Kosmos-Trident International Petroleum Inc.
“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.
"LOPI"	Loss of Production Income.
"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.
"NAMCOR"	National Petroleum Corporation of Namibia.
"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.
"NYSE"	New York Stock Exchange.
"Ophir"	Ophir Energy plc.
"PETROCI"	PETROCI Holding.
"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.
"SEC"	Securities and Exchange Commission.
"Senior Notes"	7.125% Senior Notes due 2026.
"Senior Secured Notes"	7.875% Senior Secured Notes due 2021.
"Shelf margin"	The path created by the change in direction of the shoreline in reaction to the filling of a sedimentary basin.
"Shell"	Royal Dutch Shell and related subsidiaries.
"SNPC"	Société Nationale des Pétroles du Congo.
"Stratigraphy"	The study of the composition, relative ages and distribution of layers of sedimentary rock.
"Stratigraphic trap"	A stratigraphic trap is formed from a change in the character of the rock rather than faulting or folding of the rock and oil is held in place by changes in the porosity and permeability of overlying rocks.
"Structural trap"	A topographic feature in the earth's subsurface that forms a high point in the rock strata. This facilitates the accumulation of oil and gas in the strata.
"Structural-stratigraphic trap"	A structural-stratigraphic trap is a combination trap with structural and stratigraphic features.
"Submarine fan"	A fan-shaped deposit of sediments occurring in a deep water setting where sediments have been transported via mass flow, gravity induced, processes from the shallow to deep water. These systems commonly develop at the bottom of sedimentary basins or at the end of large rivers.
"TAG GSA"	TEN Associated Gas - Gas Sales Agreement.

"TEN"	Tweneboa, Enyenra and Ntomme.
“Three-way fault trap”	A structural trap where at least one of the components of closure is formed by offset of rock layers across a fault.
"Tortue Phase 1 SPA"	Greater Tortue Ahmeyim Agreement for a Long Term Sale and Purchase of LNG.
“Trap”	A configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not migrate.
"Trident"	Trident Energy.
“Undeveloped acreage”	Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains discovered resources.
"WCTP"	West Cape Three Points.

Cautionary Statement Regarding Forward-Looking Statements

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

- our ability to find, acquire or gain access to other discoveries and prospects and to successfully develop and produce from our current discoveries and prospects;
- uncertainties inherent in making estimates of our oil and natural gas data;
- the successful implementation of our and our block partners' prospect discovery and development and drilling plans;
- projected and targeted capital expenditures and other costs, commitments and revenues;
- termination of or intervention in concessions, rights or authorizations granted to us by the governments of the countries in which we operate (or their respective national oil companies) or any other federal, state or local governments or authorities;
- our dependence on our key management personnel and our ability to attract and retain qualified technical personnel;
- the ability to obtain financing and to comply with the terms under which such financing may be available;
- the volatility of oil, natural gas and NGL prices;
- the availability, cost, function and reliability of developing appropriate infrastructure around and transportation to our discoveries and prospects;
- the availability and cost of drilling rigs, production equipment, supplies, personnel and oilfield services;
- other competitive pressures;
- potential liabilities inherent in oil and natural gas operations, including drilling and production risks and other operational and environmental risks and hazards;
- current and future government regulation of the oil and gas industry 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 environmental, health and safety or climate change or GHG laws and regulations or the implementation, or interpretation, of those laws and regulations;
- 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 tropical storms and hurricanes in the Gulf of Mexico;
- 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;
- the result of any legal proceedings, arbitrations, or investigations we may be subject to or involved in;
- our success in risk management activities, including the use of derivative financial instruments to hedge commodity and interest rate risks; and
- other risk factors discussed in the "Item 1A. Risk Factors" section of this annual report on Form 10-K.

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

PART I

Item 1. Business
General

Kosmos is a full-cycle deepwater independent oil and gas exploration and production company focused along the Atlantic Margins. Our key assets include production offshore Ghana, Equatorial Guinea and U.S. Gulf of Mexico, as well as a world-class gas development offshore Mauritania and Senegal. We also maintain a sustainable exploration program balanced between proven basin infrastructure-led exploration (Equatorial Guinea and U.S. Gulf of Mexico), emerging basins (Mauritania, Senegal and Suriname) and frontier basins (Cote d'Ivoire, Namibia, Sao Tome and Principe, and South Africa). Kosmos is listed on the NYSE and LSE and is traded under the ticker symbol KOS.

Kosmos was founded in 2003 to find oil in under-explored or overlooked parts of West Africa. In its relatively brief history, the Company has successfully opened two new hydrocarbon basins through the discovery of the Jubilee field offshore Ghana in 2007 and the Greater Tortue Ahmeyim field in 2015 (which includes the Ahmeyim and Guembeul-1 discovery wells offshore Mauritania and Senegal in 2015 and 2016, respectively). Jubilee was one of the largest oil discoveries worldwide in 2007 and is considered one of the largest finds offshore West Africa discovered during that decade. First oil production was delivered just 42 months after initial discovery, a record for a deepwater development in West Africa in this water depth. The Ahmeyim discovery was one of the largest natural gas discoveries worldwide in 2015 and is believed to be the largest ever gas discovery offshore West Africa.

Over the last two years, our business strategy has evolved to include production-enhancing infill drilling and well work as well as infrastructure-led exploration. This strategic evolution was initially enabled by our acquisition of the Ceiba Field and Okume Complex assets offshore Equatorial Guinea in October 2017 together with access to surrounding exploration licenses, and bolstered by the September 2018 acquisition of DGE, a deepwater company operating in the U.S. Gulf of Mexico, which further enhanced our production, exploitation and infrastructure-led exploration capabilities.

Our Business Strategy

As a full-cycle 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.

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 and development; and (3) add new resources through an efficient low cost exploration program. We are focused on increasing production, cash flows and reserves from our producing assets in Equatorial Guinea, Ghana, and the U.S. Gulf of Mexico. In Mauritania and Senegal, we are progressing our Greater Tortue Ahmeyim development with the objective of reaching first gas in 2022, as well as advancing our other discoveries towards a final investment decision. In addition, our exploration portfolio consists of a large inventory of leads and prospects along the Atlantic Margins, both infrastructure-led and basin opening opportunities, which we plan to continue to mature for future drilling, providing us access to additional growth potential in the coming years. We do not plan on accessing new basin opening oil positions.

Grow cash flow, proved reserves and production through exploitation, development, infrastructure-led exploration and basin opening exploration activities

In the near term, we plan to grow cash flow, proved reserves and production by further exploiting our fields offshore Ghana, U.S. Gulf of Mexico, and Equatorial Guinea. In Ghana, we plan to continue drilling additional development and production wells at both the Jubilee and TEN fields in 2020. In the U.S. Gulf of Mexico, we plan to continue development drilling on existing fields and drilling multiple infrastructure-led exploration targets. In Equatorial Guinea, our activity set is expanding beyond production optimization projects, such as utilizing electrical submersible pumps, to include infrastructure-led exploration which, if successful, can be brought online quickly via subsea tieback to existing infrastructure. In addition, we have sanctioned the first phase of the Greater Tortue Ahmeyim development offshore Mauritania and Senegal, which defines the timing and path to first gas. Beyond the phase 1 development of Greater Tortue Ahmeyim, growth could also be realized through additional development of Greater Tortue Ahmeyim and through the development of all or a portion of our other discoveries in Mauritania and Senegal. Additionally, our basin opening exploration activity include opportunities offshore Equatorial Guinea, Sao Tome and Principe, Cote d'Ivoire, Suriname, Namibia and South Africa. During 2020, we plan to mature development concepts from previous discoveries in Mauritania, Senegal and Equatorial Guinea, drill three infrastructure-led prospects and two development wells in the U.S. Gulf of Mexico, drill two infill wells in Equatorial Guinea and drill one frontier exploration well in Sao Tome and Principe.

Focus on optimally developing our discoveries to initial production

Our approach to development is designed to deliver first production on an accelerated timeline, leverage early learnings to improve future outcomes and maximize returns. In certain circumstances, we believe a phased approach can be employed to optimize full-field development. A phased approach facilitates refinement of the development plans based on experience gained in initial phases of production and by leveraging existing infrastructure as subsequent phases of development are implemented. Production and reservoir performance from the initial phases are monitored closely to determine the most efficient and effective techniques to maximize the recovery of reserves and returns. Other benefits include minimizing upfront capital costs, reducing execution risks through smaller initial infrastructure requirements, and enabling cash flow from the initial phases of production to fund a portion of capital costs for subsequent phases. Our development of the Jubilee Field is an example of this approach.

The Greater Tortue Ahmeyim development is also expected to be developed in an accelerated, phased approach consistent with our business strategy. This is anticipated to result in first gas approximately seven years after initial discovery. Lastly, our approach to discoveries in the U.S. Gulf of Mexico is to develop them via subsea tie-back to existing host facilities with existing spare capacity. This reduces the average timeline to first production.

Kosmos Exploration Approach - A balance of basin opening and infrastructure-led

Kosmos' philosophy, in new basin opening exploration, is deeply rooted in a fundamental, geologic approach geared toward the identification of under-explored or overlooked petroleum systems. Once an area of interest has been identified, Kosmos targets licenses over the particular basin or fairway to achieve an early-mover or in many cases a first-mover advantage. In terms of license selection, Kosmos targets specific regions that have sufficient size to manage exploration risks and provide scale should the exploration concept prove successful. Kosmos also looks for: (i) long-term contract durations to enable the "right" exploration program to be executed, (ii) play type diversity to provide multiple exploration concept options, (iii) prospect dependency to enhance the chance of replicating success, and (iv) sufficiently attractive fiscal terms to maximize the commercial viability of discovered hydrocarbons.

Alongside the subsurface analysis, Kosmos performs an analysis of country-specific risks to gain an understanding of the "above-ground" dynamics, which may influence a particular country's relative desirability from an overall oil and natural gas operating and risk-adjusted return perspective. This process is utilized for all new areas and is a key strength of Kosmos.

In support of delivering a sustainable, balanced exploration program, our approach has broadened to include infrastructure-led exploration. This shorter-cycle approach is aimed at areas where we have existing production and where there is sufficient infrastructure capacity to enable the development of new discoveries via subsea tieback. Acquisition of the Ceiba Field and Okume Complex in Equatorial Guinea and assets in the U.S. Gulf of Mexico have added high-quality prospectivity to our inventory of infrastructure-led exploration opportunities given their attractive acreage positions within proximity of existing infrastructure with excess capacity available. This opens a potential new growth area with attractive economics in areas with high margin production that complements the basin opening exploration program.

Build the right strategic partnerships with complementary capabilities

As a full-cycle E&P company, part of our strategy is to optimize our portfolio at appropriate times for our exploration and development projects. One way to accomplish this is to partner with high-quality industry players with world-class complementary capabilities. This strategy is designed to ensure the relative project can benefit from specific expertise provided by these partners, including exploration, development, production and above-ground capabilities. We have proven we can execute this strategy by partnering with supermajors, including BP and Shell, across our exploration portfolio. In addition, bringing in the right strategic partners early in our projects often comes with a financial carry on future expenditures, allowing us to reduce our costs and increase return on investment.

For example, the alliance formed in 2017 with a subsidiary of BP broadened our relationship to cover new venture opportunities in Mauritania, Senegal and The Gambia to create an Atlantic Margin explorer-developer partnership that leveraged Kosmos' regional exploration knowledge and capability with BP's deepwater development expertise to execute a selective, basin opening exploration strategy in the Atlantic Margin.

Similarly, during the fourth quarter of 2018, Kosmos entered into an additional strategic exploration alliance with a subsidiary of Shell to jointly explore in Southern West Africa. The alliance initially focused on Namibia where Kosmos had completed a farm-in to Shell's acreage in PEL 39, and Kosmos' Sao Tome & Principe acreage where Shell farmed into Blocks 6 and 11. In September 2019, Shell and Kosmos completed a farm-in agreement whereby Kosmos and Shell obtained interests in the Northern Cape Ultra Deep block offshore the Republic of South Africa. As part of the alliance, the two companies are also jointly evaluating opportunities in adjacent geographies. This alliance is consistent with Kosmos' strategy of partnering with supermajors to leverage complementary skill sets.

During the first quarter of 2019, Kosmos farmed-into 18 BP-owned blocks in the Garden Banks area of the deepwater U.S. Gulf of Mexico. In addition, Kosmos can earn an interest in three BP blocks in other areas of the deepwater U.S. Gulf of Mexico. This should allow Kosmos to execute projects that can be tied back to existing infrastructure. Kosmos is the designated operator.

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

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

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

Kosmos recognizes that creating long-term shareholder returns can only be achieved by advancing the societies in which we work and operating in a manner that protects the environment. Kosmos focuses on continuously improving its ESG credentials by working with a range of stakeholders, including shareholders, partners, suppliers, host governments and civil society organizations.

The company looks upon the United Nations Sustainable Development Goals as a useful template for evaluating and understanding how our activities promote economic and social progress in host countries. In 2013, we adopted the Kosmos Energy Business Principles to formalize our commitment to act as a force for good. Our Business Principles are supported by more detailed policies, procedures, and management systems. Each year, we report on our environmental, social, and governance practices and performance in our Sustainability Report and on our website.

Most recently, our ESG work has centered 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, we established governance structures to monitor and manage climate-related risks and opportunities; developed a strategy to measure and reduce greenhouse gas emissions from our own operations and mitigate remaining emissions through innovative nature-based solutions. Beginning in 2020, we plan to report on these issues in a manner aligned with the Task Force on Climate-related Disclosure (TCFD) and the Sustainability Accounting Standards Board (SASB) guidelines.

Maintain financial discipline

Execution of our strategy requires us to maintain a conservative financial approach with a strong balance sheet, ample liquidity, a commitment to low leverage and the ability to maintain significant headroom on our debt covenants. Typically, we fund exploration and development activities from a combination of operating cash flows, debt and partner carries.

As of December 31, 2019, our net leverage ratio was approximately 1.8 times as a result of utilizing our free cash flow generated in 2019 to reduce outstanding borrowings. Likewise, our liquidity increased to approximately $0.8 billion.

Additionally, we use derivative instruments to partially limit our exposure to fluctuations in oil prices. We have an active commodity hedging program where we aim to hedge a portion of our anticipated sales volumes on a two-to-three year rolling basis, with the goal to protect against the downside price scenario while still retaining partial exposure to the upside. As of December 31, 2019, we have hedged positions covering 16.0 million barrels of oil production from 2020 through 2021. We also maintain insurance to partially protect against loss of production revenues from our producing assets.

During 2019, Kosmos generated approximately $628.2 million of cash flow from operating activities.

Operations by Geographic Area

We currently have operations in Africa and the Americas. Presently, our operating revenues are generated from our operations offshore Ghana, Equatorial Guinea, and U.S. Gulf of Mexico. The following tables provide a summary of certain key 2019 data for our geographic areas.

Geographic Area	Sales Volumes (Net to Kosmos)	Percentage of Total Sales Volumes	Revenue	Year-End Estimated Proved Reserves(1)	Percentage of Total Estimated Proved Reserves
	(in MMboe)		(in thousands)	(in MMboe)	
Ghana	11.4	46%	$ 738,909	95	56%
Equatorial Guinea	4.7	19%	300,547	28	17%
Mauritania / Senegal(2)	—	—	—	—	—
U.S. Gulf of Mexico	8.8	35	459,960	46	27
Total	24.9	100%	$ 1,499,416	169	100%

(1) For information concerning our estimated proved reserves as of December 31, 2019, see “—Our Reserves.”

(2) The Tortue Phase 1 SPA was signed on February 11, 2020, resulting in approximately 100 MMBoe of proved undeveloped reserves being recognized at that time as evaluated by the company's independent reserve auditor Ryder Scott, LP.

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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)	24.1% (2)	Tullow	Production	2034
TEN	DT	17.0% (4)	Tullow	Production	2036
U.S. Gulf of Mexico(1)					
Barataria	MC 521	22.5%	Kosmos	Production	(8)
Big Bend	MC 697 / 698 / 742	5.3%	Fieldwood	Production	(8)
Don Larsen	EB 598	20.0%	Occidental	Production	(8)
Gladden	MC 800	20.0%	W&T	Production	(8)
Kodiak	MC 727 / 771	29.1%	Kosmos	Production	(8)
Marmalard	MC 255 / 300	11.4%	Murphy	Production	(8)
Nearly Headless Nick	MC 387	21.9%	Murphy	Production	(8)
Danny Noonan	EC 381 / GB 506	30.0%	Talos	Production	(8)
Odd Job	MC 214 / 215	Various (5)	Kosmos	Production	(8)
Sargent	GB 339	50.0%	Kosmos	Production	(8)
SOB II	MC 431	11.4%	Murphy	Production	(8)
S. Santa Cruz	MC 563	40.5%	Kosmos	Production	(8)
Tornado	GC 281	35.0%	Talos	Production	(8)
Mauritania					
Greater Tortue Ahmeyim	Block C8 (3)	26.8%	BP	Development	2049(9)
Marsouin	Block C8	28.0% (6)	BP	Appraisal	2022
Orca	Block C8	28.0% (6)	BP	Appraisal	2022
Senegal					
Greater Tortue Ahmeyim	Saint Louis Offshore Profond (3)	26.7%	BP	Development	2044(10)
Teranga	Cayar Offshore Profond	30.0% (7)	BP	Appraisal	2021
Yakaar	Cayar Offshore Profond	30.0% (7)	BP	Appraisal	2021
Equatorial Guinea(1)					
Ceiba Field and Okume Complex	Block G	40.4%	Trident	Production	2034

(1) For information concerning our estimated proved reserves as of December 31, 2019, 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 the 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.

These interest percentages are 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 26.9%.

(3) The Greater Tortue Ahmeyim Unit, which includes the Ahmeyim discovery in Mauritania Block C8 and the Guembeul discovery in the Senegal Saint Louis Offshore Profond Block, straddles the border between Mauritania and Senegal. To optimize resource recovery in this field, we entered into the GTA UUOA in February 2019 with the governments of Mauritania and Senegal. 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. Our current payment interest on development activities in the Greater Tortue Ahmeyim Unit is 26.7%.

(4) Our paying interest on development activities in the TEN fields is 19%.

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

(6) SMHPM has the option to acquire up to an additional 4% participating interest in a commercial development on Block C8. These interest percentages do not give effect to the exercise of such option.

(7) PETROSEN has the option to acquire up to an additional 10% participating interest in a commercial development on the Saint Louis Offshore Profond and Cayar Offshore Profond Blocks. The interest percentage does not give effect to the exercise of such option.

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

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

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

Exploration License and Lease Areas

Country	Number of Blocks	Kosmos Average Participating Interest		Operator(s)	Current Phase License Expiration Range	
Cote d'Ivoire	5	45.0%	(1)	Kosmos	2020	(9)
Equatorial Guinea	4	50.0%	(2)	Kosmos	2020-2021	(9)
Mauritania	4	28.0%	(3)	BP	2020-2022	(9)
Namibia	1	45.0%	(4)	Shell	2022	(9)
Sao Tome and Principe	6	39.0%	(5)	Kosmos, BP, Galp	2020-2022	(9)
Senegal	2	30.0%	(6)	BP	2021	
South Africa	1	45.0%	(7)	Shell	2021	(9)
Suriname	2	41.5%	(8)	Kosmos	2020-2021	(9)
U.S. Gulf of Mexico	79	53.0%		Kosmos, Chevron, Murphy, Talos, Fieldwood, Occidental, W&T Offshore	through 2029	(10)

(1) PETROCI has the option to acquire up to an additional 2% paying interests in a commercial development. The interest percentage does not give effect to the exercise of such option.

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

(3) Should a commercial discovery be made, SMHPM's 10% carried interest is extinguished and SMHPM will have an option to obtain a participating interest in the discovery area between 10% and 14% (blocks C8, C12 and C13) and 10% and 18% (Block C6). SMHPM will pay its portion of development and production costs in a commercial development on the blocks. The interest percentage does not give effect to the exercise of such option.

(4) Should a commercial discovery be made, NAMCOR's 10% carried interest during the exploration period may continue through first commercial production but must be reimbursed through production.

(5) 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. Formal withdraw notice on STP Block 12 was communicated to partners on December 13, 2019 and was effective January 31, 2020.

(6) PETROSEN has the option to obtain up to an additional 10% paying interest in a commercial development on the Saint Louis Offshore Profond and Cayar Offshore Profond Blocks. The interest percentage does not give effect to the exercise of such option.

(7) The Republic of South Africa has the option to obtain a percentage of the participating interest ("State Option") in accordance with the provisions of the Applicable Laws prevailing at the time of the granting of a Production Right governing State Option requirements.

(8) Should a commercial discovery be made, Staatsolie has the option to participate up to 10% in Block 42 and up to 15% in Block 45 in each commercial discovery. Staatsolie will pay its portion of development and production costs in a commercial development in which it participates.

(9) License expiration date can be extended beyond the current exploration period upon completion of required work program and subject to additional work obligations.

(10) Our U.S. Gulf of Mexico blocks can be held by continued operations, and the lease periods on blocks that are held by continued operations extend as long as governmental approved operations continue on the relevant block. This can extend the license expiration to a date later than 2029.

Ghana

The WCTP Block and DT Block are located within the Tano Basin, offshore Ghana. This basin contains a proven world-class petroleum system as evidenced by our discoveries. The following is a brief discussion of our discoveries on our license areas offshore Ghana.

Jubilee Field

The Jubilee Field was discovered by Kosmos in 2007, with first oil produced in November 2010. Appraisal activities confirmed that the Jubilee discovery straddled the WCTP and DT Blocks. Pursuant to the terms of the Jubilee UUOA, the discovery area was unitized for purposes of joint development by the WCTP and DT Block partners.

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 is being 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 GJFFDP was approved by the Government of Ghana in October 2017. This plan has been optimized to reduce overall capital expenditures to reflect the current oil price market. In November 2015, we signed the Jubilee Field Unit Expansion Agreement with our partners, which became effective upon approval of the GJFFDP, to allow for the development of the Mahogany and Teak discoveries as part of the Jubilee Field Unit through the Jubilee FPSO and infrastructure, thus reducing their development cost. As a result of the approval of the GJFFDP by the Ministry of Energy in October 2017, operatorship for the Mahogany and Teak discoveries transferred to Tullow. The WCTP partners transferred operatorship of the remaining portions of the WCTP Block, including the Akasa discovery, to Tullow effective February 1, 2018.

The Government of Ghana completed the construction and connection of a gas pipeline in 2017 from the Jubilee Field to transport natural gas to the mainland for processing and sale. In the absence of continuous export of large quantities of natural gas from the Jubilee Field, it is anticipated that we will need to reinject or flare such natural gas. Our inability to continuously export associated natural gas in large quantities from the Jubilee Field could impact our oil production.

In February 2016, the Jubilee Field operator identified an issue with the turret bearing of the FPSO Kwame Nkrumah. Kosmos and its partners completed the lifting and locking of the main turret bearing, and the rotation of the vessel to its final heading in the second half of 2018. Permanent spread mooring of the vessel was completed in 2019. The final phase of the Turret Remediation Project, the installation and commissioning of the catenary anchor leg mooring ("CALM") Buoy, is expected to be completed around mid-year 2020. The financial impact of the additional expenditures associated with the damage to the turret bearing was mitigated through H&M insurance.

Oil production from the Jubilee Field averaged approximately 87,400 Bopd gross (20,000 Bopd net) during 2019.

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 are being jointly developed with shared infrastructure and a single FPSO, with first oil produced in August 2016.

Similar to Jubilee, the TEN fields are being developed in a phased manner. The TEN PoD was designed to include an expandable subsea system that would provide for multiple phases.

Oil production from TEN averaged approximately 61,100 Bopd gross (9,900 Bopd net) during 2019.

The construction and connection of a gas pipeline between the Jubilee and TEN fields to transport natural gas to the mainland for processing and sale was completed in the first quarter of 2017. In December 2017, we signed the TAG GSA. Our inability to continuously export associated natural gas in large quantities from the TEN fields could impact our oil production.

U.S. Gulf of Mexico

In September 2018, as part of the DGE transaction, Kosmos acquired: (i) a portfolio of producing assets that Kosmos can continue to exploit, (ii) infrastructure-led exploration growth assets, and (iii) a high-quality inventory of exploration prospects across the East Breaks, Garden Banks, Green Canyon and Mississippi Canyon areas. After the acquisition, we have expanded our inventory through the U.S. Gulf of Mexico Federal lease sales and farm-in transactions, including expansion into the Walker Ridge, De Soto Canyon and Keathley Canyon areas of the U.S. Gulf of Mexico. Our U.S. Gulf of Mexico assets averaged approximately 24,100 Boepd (net) (~ 82% oil) from 13 fields during 2019.

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

Odd Job

The Odd Job field is producing through the Delta House FPS, operated by Murphy. The technical team initially identified the Middle Miocene sands at the Odd Job prospect, and these sands are currently producing. The Odd Job 214 #2 well, the third well in the Odd Job field, was drilled in 2018, and came online in the fourth quarter of 2019. Net production during 2019 averaged approximately 7,200 Boepd.

Tornado

The Tornado field is producing from three Pliocene wells through the Helix Producer I, a ship-shaped, dynamically-positioned production platform in the deepwater U.S. Gulf of Mexico, which is operated by Talos Energy. A water injection well is expected to be drilled in 2020 to help enhance overall recoveries in the Tornado field. Net production during 2019 averaged approximately 6,000 Boepd.

Marmalard

The Marmalard field produces from four wells, each completed in Middle Miocene sands. These wells are flowing through the Delta House FPS, operated by Murphy. Net production during 2019 averaged approximately 2,800 Boepd.

Kodiak

The Kodiak field is producing from one well, which is completed in the Middle Miocene sands. This well is flowing through the Devils Tower Spar platform, which is operated by ENI. A second development well is anticipated to be drilled and completed during 2020. Net production during 2019 averaged approximately 3,400 Boepd.

South Santa Cruz / Barataria

The South Santa Cruz field is producing from one well in a Late Miocene sand. The Barataria field is also producing from one well in a Late Miocene sand. Both fields produce through the Blind Faith tension-leg platform, which is operated by Chevron. Net production from these two wells during 2019 averaged approximately 2,400 Boepd.

Mauritania

The C6, C8, C12, and C13 blocks are located on the western margin of the Mauritania Salt Basin offshore Mauritania and range in water depths from 100 to 3,000 meters. These blocks are located in a proven petroleum system, with our primary targets being Cretaceous sands in structural and stratigraphic traps.

These blocks cover an aggregate area of approximately 4.9 million acres (gross). We have acquired approximately 6,200 line-kilometers of 2D seismic data and 21,700 square kilometers of 3D seismic data covering portions of our blocks in Mauritania. Based on these 2D and 3D seismic programs, we have drilled three successful exploration wells and an appraisal well and have identified additional prospects in our blocks. We continue to integrate the results of our drilling program in Mauritania.

In the second quarter of 2019, we withdrew from Block C18 offshore Mauritania.

Senegal

The Senegal Blocks are located in the Senegal River Cretaceous petroleum system and range in water depth from 300 to 3,100 meters. The area is an extension of the working petroleum system in the Mauritania Salt Basin. We acquired approximately 7,500 square kilometers of 3D seismic data over the central and eastern portions of the Senegal Blocks in January 2015. In February 2016, we completed a 4,600 square kilometer survey over the western portions of the Senegal Blocks to fully evaluate the prospectivity. We have drilled three successful exploration wells and two appraisal wells.

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

Greater Tortue Ahmeyim Development

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

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

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

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

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

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

In December 2018, the partners agreed on a final investment decision for Phase 1 of the Greater Tortue Ahmeyim project. The Greater Tortue Ahmeyim project is designed to produce gas from a deepwater subsea system to a mid-water FPSO and then to a FLNG facility at a nearshore hub located on the Mauritania and Senegal maritime border. The FLNG facility for Phase 1 is designed to produce approximately 2.5 million tons per annum on average. The project will provide LNG for global export, as well as make gas available for domestic use in both Mauritania and Senegal. First gas for the project is expected in the first half of 2022. Following a competitive tender process involving all partners and subject to final documentation, BP Gas Marketing has been selected as the buyer for the LNG offtake for Greater Tortue Ahmeyim Phase 1. Additionally, in February 2020 the Tortue Phase 1 SPA was executed.

Other Mauritania and Senegal Discoveries

BirAllah and Orca Discoveries

The BirAllah discovery (formally known as Marsouin), located in Block C8 offshore Mauritania, is a significant, play-extending gas discovery, building on our successful exploration program in the outboard Cretaceous petroleum system offshore Mauritania. The Marsouin-1 well is located approximately 60 kilometers north of the Ahmeyim discovery and was drilled to a total depth of 5,150 meters in nearly 2,400 meters of water. Based on analysis of drilling results and logging data, Marsouin-1 encountered at least 70 meters of net gas pay in Upper and Lower Cenomanian intervals comprised of excellent quality reservoir sands.

The Orca-1 well, located in Block C8 offshore Mauritania, was drilled in October 2019 and delivered a major gas discovery. The Orca-1 well, which targeted a previously untested Albian play, encountered 36 meters of net gas pay in excellent quality reservoirs. In addition, the well extended the Cenomanian play fairway by confirming 11 meters of net gas pay in a down-structure position relative to the original Marsouin-1 discovery well. The location of the Orca-1 well proved both the structural and stratigraphic components of the trap are working, thereby proving a significant volume. The Orca-1 well was drilled in approximately 2,510 meters of water to a total measured depth of around 5,266 meters.

In total, we believe that Orca-1 and Marsouin-1 have de-risked more than sufficient resource to support a world-scale LNG project from the Cenomanian and Albian plays in the BirAllah area.

Yakaar and Teranga Discoveries

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

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

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

Equatorial Guinea

In October 2017, we entered into petroleum contracts covering Blocks EG-21, S, and W with the Republic of Equatorial Guinea. The petroleum contracts cover approximately 6,000 square kilometers, with a first exploration period expiring in March 2023. The first exploration period consists of two sub-periods of three and two years, respectively. The first exploration sub-period work program included an approximately 6,000 square kilometer 3D seismic acquisition requirement across the blocks, which was completed in November 2018.

In June 2018, we closed a farm-in agreement with a subsidiary of Ophir for Block EG-24, offshore Equatorial Guinea, whereby we acquired a 40% non-operated participating interest. The petroleum contract covers approximately 3,500 square kilometers, with a first exploration period of three years from the effective date (March 2018), which can be extended up to four additional years at our election subject to fulfilling specific work obligations. The first exploration period work program includes a 3,000 square kilometer 3D seismic acquisition requirement, which was completed in November 2018. In the first quarter of 2019, we acquired Ophir's remaining interest in and operatorship of the block, which results in Kosmos owning an 80% interest in Block EG-24. Should a commercial discovery be made, GEPetrol's 20% carried interest will convert to a 20% participating interest for all development and production operations.

In November 2018, we completed a 3D seismic survey of approximately 9,500 square kilometers over blocks EG-21, EG-24, S and W offshore Equatorial Guinea, and approximately 200 square kilometers over Block G. The seismic data is being interpreted with the objective of high grading prospects for future drilling as early as 2021.

Ceiba Field and Okume Complex

In the fourth quarter of 2017, through a joint venture with an affiliate of Trident, we acquired all of the equity interest of Hess International Petroleum Inc., a subsidiary of Hess, which held an 85% paying interest (80.75% revenue interest) in the Ceiba Field and Okume Complex assets. Under the terms of the agreement, Kosmos and Trident each owned 50% of Hess International Petroleum Inc. Hess International Petroleum Inc. was subsequently renamed KTIPI. Kosmos is primarily responsible for exploration and subsurface evaluation while Trident is primarily responsible for production operations and optimization. The transaction expands our position in the Gulf of Guinea and provides immediate cash flow through existing production with potential to increase existing production through exploration opportunities with potential low cost tie-backs through the existing infrastructure. The gross acquisition price was $650 million effective as of January 1, 2017. After post closing entries Kosmos paid net cash of approximately $231 million. The transaction was accounted for as an equity method investment.

Effective as of January 1, 2019, our outstanding shares in KTIPI were transferred to Trident in exchange for a 40.4% undivided participating interest in the Ceiba Field and Okume Complex. As a result, our interest in the Ceiba Field and Okume Complex is accounted for under the proportionate consolidation method of accounting going forward. Oil production from the Ceiba Field and Okume Complex averaged approximately 38,300 Bopd gross (12,100 Bopd net) of oil per day during 2019.

In May 2018, we signed a farm-out agreement with a subsidiary of Trident covering blocks S, W and EG-21 offshore Equatorial Guinea, and completed the farm-out agreement in August of 2018. Under the terms of the agreement, Trident acquired a 40% non-operated participating interest in the blocks and Kosmos remains the operator.

Asam Discovery

In October 2019, the S-5 exploration well was drilled to a total depth of 4,400 meters offshore Equatorial Guinea, encountering 39 meters of net oil pay in good-quality Santonian reservoir. The well is located within tieback range of the Ceiba FPSO and work is currently ongoing to establish the scale of the discovered resource and evaluate the optimum development solution.

Suriname

We are the operator for petroleum contracts covering Block 42 and Block 45 offshore Suriname, which are located within the Guyana Suriname Basin, along the Atlantic transform margin of northern South America. Suriname lies between Guyana to the west and French Guyana to the east. The Suriname basin is analogous to the working petroleum systems of the West African transform margin. The emerging petroleum system in Suriname has been proven by the presence of onshore producing fields and most recently by the nearby Maka Central-1 discovery offshore Suriname Block 58, as well as the discoveries offshore Guyana, including the Liza-1 well.

Suriname Block 42 and Block 45 are positioned centrally in the Suriname-Guyana Basin, and located to the east of the play opening Liza-1 oil discovery. Likewise, the blocks are also positioned to the northeast of the Maka Central-1 discovery offshore Suriname. Of note are the stratigraphically trapped Upper Cretaceous plays similar to the discoveries in Guyana (Liza-1) and Suriname (Maka Central-1), and a carbonate reef play analagous to the Ranger-1 discovery in Guyana. These plays are located in the same geologic basin providing positive points of calibration for the prospectivity in Suriname Block 42.

The Tambaredjo and Calcutta Fields onshore Suriname, as well as the Liza-1 well discovery offshore Guyana, demonstrate that a working petroleum system exists, and geological and geochemical studies suggest the hydrocarbons in these fields were generated from source rocks located in the offshore basin. The source rocks are believed to be analogous in age to those which have charged numerous fields in offshore West Africa.

In June 2018, the Anapai-1A exploration well was drilled in Block 45 to a total depth of approximately 4,600 meters and was fully tested, encountering high quality reservoirs in the targeted zones, but did not find hydrocarbons. The well has been plugged and abandoned.

In July 2018, we entered into the second exploration phase in Blocks 42 and 45, which now expires in September 2021. The second phase carried a one well commitment per block that has been met for both blocks with the Anapai-1A and Pontoenoe-1 exploration wells.

In October 2018, the Pontoenoe-1 exploration well was drilled in Block 42 to a total depth of approximately 6,200 meters and was fully tested but did not discover commercial hydrocarbons. High-quality reservoir was encountered, but the primary exploration objective proved to be water bearing. The well has been plugged and abandoned.

Recent well results are being integrated into the ongoing evaluation of the remaining prospectivity in our Suriname acreage position, with the objective of high-grading a prospect for drilling in 2021.

Sao Tome and Principe

We are operator for petroleum contracts covering Blocks 5 and 11 and maintain a non-operated position in Blocks 6, 10 and 13 offshore Sao Tome and Principe in the Gulf of Guinea. Galp, a wholly-owned subsidiary of Petrogal, S.A., is the operator of Block 6. BP is the operator of Blocks 10 and 13. These blocks cover an area of approximately 8.5 million acres (gross) in water depths ranging from 2,250 to 3,000 meters and provide an opportunity to pursue the same core Cretaceous theme that was successful for us in Ghana.

Our blocks are adjacent to, and represent an extension of, a proven and prolific petroleum system offshore Equatorial Guinea and northern Gabon comprising Early Cretaceous post-rift source rocks and Late Cretaceous reservoirs. Kosmos has established an extensive position in the Rio Muni Basin where there is a proven source and reservoir inboard with the Ceiba and Okume discoveries in Equatorial Guinea, which appears to extend outboard into the deepwater in Sao Tome and Principe, where there are oil seeps on both islands. Kosmos has identified large potential structural and stratigraphic traps on early seismic, which is currently being processed.

We believe that the southern extent of the West African transform margin in Sao Tome and Principe comprises a series of basins formed during the separation of Africa from South America, providing the necessary conditions for the generation, migration and entrapment of hydrocarbons. Large deep-water slope channels and basin floor fans draping over and around anticlinal highs adjacent to fracture zones constitute the main play in the acreage.

In August 2017, we completed a 3D seismic survey of approximately 15,800 square kilometers offshore Sao Tome and Principe. Processing has been completed. We are compiling an inventory of prospects on the license areas in Sao Tome and Principe and will continue to refine and assess the prospectivity, integrating this new 3D seismic data into our geological evaluation. We plan to drill an exploration well in Block 6 offshore Sao Tome and Principe in late 2020.

In the fourth quarter of 2019, formal withdrawal notice from Block 12 offshore Sao Tome and Principe was communicated to partners with an effective date of January 31, 2020.

Cote d'Ivoire

In December 2017, as part of our Alliance with BP, we entered into petroleum contracts as operator for five Offshore Blocks, CI-526, CI-602, CI-603, CI-707 and CI-708, which are located approximately 150 kilometers west of our TEN discoveries in Ghana in water depth from 450 to 4,500 meters. We believe the area has multiple Cretaceous source rocks with Cenomanian through Maastrichtian reservoir sands providing the potential for exploration targets. We are compiling an inventory of prospects on the license areas in Cote d'Ivoire and will continue to refine and assess the prospectivity, integrating the 3D seismic data acquired in May 2018 into our geological evaluation. Following evaluation, a decision will be made on future exploration plans prior to the expiry of the current exploration phase in December 2020.

Namibia

In September 2018, we acquired a 45% non-operated participating interest in PEL 39 offshore Namibia, which later became part of a larger strategic alliance with Shell to jointly explore in Southern West Africa. The block covers an area of approximately 3.1 million acres in water depth ranging from 250 to 3,000 meters. The blocks provide for multiple plays targeting Cretaceous deepwater systems with reservoir sands sourced from the Orange River. In January 2019, we completed a 3D seismic survey covering approximately 7,400 square kilometers. Processing of this data is complete. We are compiling an inventory of prospects on the license and continue to refine and assess the prospectivity and petroleum systems analysis while integrating the new 3D seismic data in our geological evaluation with a view to drilling in early 2021.

Republic of South Africa

In September 2019, we completed a farm-in agreement with OK Energy to acquire a 45% non-operated interest in the Northern Cape Ultra Deep block offshore the Republic of South Africa. Shell owns 45% of the block and is the operator and OK Energy retained 10%. The petroleum contract covers approximately 6,930 square kilometers at water depths ranging from 2,500 to 3,100 meters and has an initial exploration phase of two years. We believe this block contains Cretaceous deepwater sand systems and the same Aptian Kudu source rock proven by discoveries north of this block, in Namibia. During 2020, we will design a 2D seismic survey to be acquired during 2021 in order to high-grade areas for a potential 3D seismic survey in the future.

Republic of Congo

In March 2019, we entered into a petroleum contract covering the offshore Marine XXI block with the Republic of the Congo, subject to governmental approvals. Upon approval, we will hold an 85% participating interest and be the operator. The Congolese national oil company, SPNC, has a 15% carried participating interest during the exploration period. Should a commercial discovery be made, SNPC's 15% carried interest will convert to a participating interest of at least 15%. The petroleum contract covers approximately 2,350 square kilometers, with a first exploration period of four years and includes a work program to acquire and interpret 2,200 square kilometers of 3D seismic. There are two optional exploration phases, each for a period of three years, which are subject to additional work program commitments.

Our Reserves

The following table sets forth summary information about our estimated proved reserves as of December 31, 2019. 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, 2019, were associated with our fields in Ghana, Equatorial Guinea, and the U.S. Gulf of Mexico. Our estimated proved reserves as of December 31, 2018, were associated with our fields in Ghana and the U.S. Gulf of Mexico as well as our share of our equity method investment in the Ceiba Field and Okume Complex in Equatorial Guinea. Our estimated proved reserves as of December 31, 2017 were associated with our fields in Ghana as well as our share of our equity method investment in the Ceiba Field and Okume Complex in Equatorial Guinea.

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Summary of Oil and Gas Reserves

	2019 Net Proved Reserves(1)			2018 Net Proved Reserves(1)			2017 Net Proved Reserves(1)		
	Oil, Condensate, NGLs	Natural Gas(3)	Total	Oil, Condensate, NGLs	Natural Gas(3)	Total	Oil, Condensate, NGLs	Natural Gas(3)	Total
	(MMBbl)	(Bcf)	(MMBoe)	(MMBbl)	(Bcf)	(MMBoe)	(MMBbl)	(Bcf)	(MMBoe)
Reserves Category									
Proved developed									
Ghana(2)	47	31	52	48	33	54	59	38	65
Equatorial Guinea(4)	23	12	25	—	—	—	—	—	—
Mauritania/Senegal(5)	—	—	—	—	—	—	—	—	—
U.S. Gulf of Mexico	34	28	39	33	25	37	—	—	—
Total proved developed	104	71	116	82	57	91	59	38	65
Proved undeveloped									
Ghana(2)	41	14	43	34	14	36	23	11	24
Equatorial Guinea(4)	3	—	3	—	—	—	—	—	—
Mauritania/Senegal(5)	—	—	—	—	—	—	—	—	—
U.S. Gulf of Mexico	6	7	7	12	13	14	—	—	—
Total proved undeveloped(6)	50	21	53	45	28	50	23	11	24
Total Kosmos proved reserves	154	92	169	127	85	141	82	49	89
Equity method investment(4)				24	14	27	19	13	21
Total proved reserves				151	99	167	100	61	110

(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 quantities of fuel gas required to operate the Jubilee and TEN FPSOs during normal field operations and the associated gas forecasted to be exported from TEN. This volume of associated gas is included as of December 31, 2017 as a result of the finalization of the TAG GSA. If and when a subsequent gas sales agreement is executed for Jubilee, a portion of the remaining Jubilee gas may be recognized as reserves. If and when a gas sales agreement and the related infrastructure are in place for the TEN fields non-associated gas, a portion of the remaining gas may be recognized as reserves.

(4) We disclosed our share of reserves that were accounted for by the equity method. Effective of January 1, 2019, our outstanding shares in KTIPI were transferred to Trident in exchange for a 40.4% undivided participating interest in the Ceiba Field and Okume Complex. As a result, our interest in the Ceiba Field and Okume Complex is accounted for under the proportionate consolidation method of accounting going forward.

(5) The Tortue Phase 1 SPA was signed on February 11, 2020, resulting in approximately 100 MMBoe of proved undeveloped reserves being recognized at that time as evaluated by the company's independent reserve auditor Ryder Scott, LP.

(6) All of our proved undeveloped reserves are expected to be developed within six years or less. Proved undeveloped reserves expected to be developed beyond five years are related to long-term projects which will be completed under a continuous drilling program.

Changes at Jubilee include a positive revision of 8.2 MMBbl related to positive drilling results and increased original oil in place, and optimized development plan, partially offset by net Jubilee production of 7.6 MMBbl. Changes at TEN include an increase of 8.8 MMBoe related to original oil in place adjustments based on updated static modeling and development plan updates, partially offset by net TEN production of 3.8 MMBoe. Changes at Equatorial Guinea include an increase of 6.3 MMBbl due to production optimization plans and plans for new drilling, which was offset by 4.7 MMBbl of net production. Changes at the U.S. Gulf of Mexico include an increase of 2.9 MMBoe related to strong performance of certain fields and the Gladden Deep discovery, offset by net U.S. Gulf of Mexico production of 8.8 MMBoe.

During the year ended December 31, 2019, we had an addition of 16.1 MMBoe of proved undeveloped reserves as a result of several factors, including updated original oil in place due to positive drilling results and improved static models in Jubilee and TEN, plans for one new well to be drilled in TEN and three new wells to be drilled in the Okume Complex.

We converted a total of 13.7 MMBoe of proved undeveloped reserves to proved developed due to completions of three new wells in Jubilee, two new wells in TEN, and three new wells in the U.S. Gulf of Mexico with a combined cost of $176.7 million. We spent $41.6 million to convert 4.0 MMBbl of proved undeveloped reserves in Jubilee and $12.8 million to convert 2.5 MMBoe proved undeveloped reserves in TEN; and $122.3 million spent to convert 7.2 MMBoe of proved undeveloped reserves in the U.S. Gulf of Mexico.

Changes for the year ended December 31, 2018, include an addition of 51.1 MMBoe as a result of the acquisition of DGE. Changes at Greater Jubilee include a revision of 9.4 MMBbl related to strong field performance, positive drilling results and increased original oil in place, partially offset by 6.4 MMBbl of net Jubilee production during 2018. Changes at TEN include a positive revision of 4.2 MMBbl due to original oil in place adjustments, new drilling and development plan updates, and a negative revision of 3.1 MMBbl due to recovery factor adjustment from dynamic modeling, which in total were offset by 3.7 MMBoe of net production. Changes at Equatorial Guinea include an increase of 11.0 MMBbl, which comprises 0.7 MMBbl of revision due to economic modeling, 3.9 MMBbl of revision due to strong field performance at both Ceiba and Okume Complex, and 6.4 MMBbl of revision due to reservoir management strategies (re-opening shut-in wells, stimulations, surface/subsurface equipment installation), all of which was partially offset by 5.4 MMBbl of net production. During the year ended December 31, 2018, we had an addition of 13.9 MMBoe of proved undeveloped reserves as a result of the DGE acquisition. We converted 2.0 MMBbl of proved undeveloped reserves to proved developed reserves in TEN incurring $9.7 million drilling a new well. We added 12.9 MMBbl of proved undeveloped reserves in Jubilee as a result of several factors, including additional data from drilling two new wells, increased oil-in-place due to improved static model utilizing new seismic and petrophysics data, and upgrading volumes associated with the Mahogany area that is now part of the Greater Jubilee Unit. We incurred $27.2 million in drilling the two Jubilee wells, however, we note that we did not have a net migration of proved undeveloped reserves to proved developed reserves due to negative revisions in Jubilee proved developed reserves, which more than offset the effects of drilling two wells during the year.

Changes for the year ended December 31, 2017, include an increase of 15.6 MMBbl in Jubilee related to the approval of the GJFFDP, partially offset by 7.7 MMBbl of net Jubilee production during 2017. Changes at TEN include an increase of 7.2 MMBoe as a result of positive Ntomme performance and the finalization of the TAG GSA, which was partially offset by 3.3 MMBbl of net TEN production during 2017. As a result of the approval of the GJFFDP, we now have 10.4 MMBbl of proved undeveloped reserves in the Greater Jubilee area, representing future infill drilling plans. Changes for 2017 also include the initial certification of proved volumes in Equatorial Guinea, representing the reserves associated with our equity method investment.

The following table sets forth the estimated future net revenues, excluding derivatives contracts, from net proved reserves and the expected benchmark prices used in projecting net revenues at December 31, 2019. All estimated future net revenues are attributable to projected production from Ghana, Equatorial Guinea and the U.S. Gulf of Mexico. If we are unable to export associated natural gas in large quantities from the Jubilee and TEN fields then production could be limited and the future net revenues discussed herein could be adversely affected.

	Estimated Future Net Revenues (in millions except $/Bbl)				
	Ghana	**Equatorial Guinea**	**Mauritania / Senegal(4)**	**U.S Gulf of Mexico**	**Total**
Estimated future net revenues	$ 3,127	$ 575	$ —	$ 1,500	$ 5,202
Present value of estimated future net revenues:					
PV-10(1)	$ 2,103	$ 526	$ —	$ 1,184	$ 3,813
Future income tax expense (levied at a corporate parent and intermediate subsidiary level)	(1,026)	(317)	—	$ (123)	$ (1,466)
Discount of future income tax expense (levied at a corporate parent and intermediate subsidiary level) at 10% per annum	349	85	—	38	472
Standardized Measure(2)	$ 1,426	$ 294	$ —	$ 1,099	$ 2,819

Benchmark Dated Brent oil price($/Bbl)(3)	$ 62.69
Benchmark HLS oil price($/Bbl)(3)	$ 61.31
Benchmark Henry Hub gas price($/MMBtu)(3)	$ 2.58

(1) PV-10 represents the present value of estimated future revenues to be generated from the production of proved oil and natural gas reserves, net of future development and production costs, royalties, additional oil entitlements and future tax expense levied at an asset level, using prices based on an average of the first-day-of-the-months throughout 2019 and costs as of the date of estimation without future escalation, without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, and discounted using an annual discount rate of 10% to reflect the timing of future cash flows. PV-10 is a non-GAAP financial measure and often differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of future income tax expense related to proved oil and gas reserves levied at a corporate parent level on future net revenues. However, it does include the effects of future tax expense levied at an asset level. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas assets. PV-10 should not be considered as an alternative to the Standardized Measure as computed under GAAP; however, we and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific corporate tax characteristics of such entities.

(2) Standardized Measure represents the present value of estimated future cash inflows to be generated from the production of proved oil and natural gas reserves, net of future development and production costs, future income tax expense related to our proved oil and gas reserves levied at a corporate parent and intermediate subsidiary level, royalties, additional oil entitlements and future tax expense levied at an asset level, without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, and discounted using an annual discount rate of 10% to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized Measure often differs from PV-10 because Standardized Measure includes the effects of future income tax expense related to our proved oil and gas reserves levied at a corporate parent level on future net revenues.

(3) This amount represents the unweighted arithmetic average first-day-of-the-month prices for the prior 12 months at December 31, 2019 for the respective benchmark. The benchmark price was adjusted for handling fees, transportation fees, quality, and a regional price differential.

(4) The Tortue Phase 1 SPA was signed on February 11, 2020, resulting in approximately 100 MMBoe of proved undeveloped reserves being recognized at that time as evaluated by the company's independent reserve auditor Ryder Scott, LP.

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, 2019, 2018 and 2017 has been prepared by RSC, our independent reserve engineering firm for such years, in accordance with the rules and regulations of the SEC applicable to companies involved in oil and natural gas producing activities. These rules require SEC reporting companies to prepare their reserve estimates using reserve definitions and pricing based on 12-month historical unweighted first-day-of-the-month average prices, rather than year-end prices. For a definition of proved reserves under the SEC rules, see the “Glossary and Selected Abbreviations.” For more information regarding our independent reserve engineers, please see “—Independent petroleum engineers” below.

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

Future net revenues represent projected revenues from the sale of proved reserves net of production and development costs (including operating expenses and production taxes). Such calculations at December 31, 2019 are based on costs in effect at December 31, 2019 and the 12-month unweighted arithmetic average of the first-day-of-the-month price for the year ended December 31, 2019, adjusted for anticipated market premium, without giving effect to derivative transactions, and are held constant throughout the life of the assets. There can be no assurance that the proved reserves will be produced within the periods indicated or prices and costs will remain constant.

Independent petroleum engineers

Ryder Scott Company, L.P.

RSC, our independent reserve engineers for the years ended December 31, 2019, 2018 and 2017, was established in 1937. For over 80 years, RSC has provided services to the worldwide petroleum industry that include the issuance of reserves reports and audits, appraisal of oil and gas properties including fair market value determination, reservoir simulation studies, enhanced recovery services, expert witness testimony, and management advisory services. RSC professionals subscribe to a code of professional conduct and RSC is a Registered Engineering Firm in the State of Texas.

For the years ended December 31, 2019, 2018 and 2017, 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, 2019, 2018 and 2017 and related future net revenues and PV-10 at December 31, 2019, 2018 and 2017 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, 2019 reserve report was completed on January 13, 2020, and a copy is included as an exhibit to this report.

In connection with the preparation of the December 31, 2019, 2018 and 2017 reserves report, RSC prepared its own estimates of our proved reserves. In the process of the reserves evaluation, RSC did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices or any agreements relating to current and future operations of the fields and sales of production. However, if in the course of the examination something came to the attention of RSC which brought into question the validity or sufficiency of any such information or data, RSC did not rely on such information or data until it had satisfactorily resolved its questions relating thereto or had independently verified such information or data. RSC independently prepared reserves estimates to conform to the guidelines of the SEC, including the criteria of “reasonable certainty,” as it pertains to expectations about the recoverability of reserves in future years, under existing economic and operating conditions, consistent with the definition in Rule 4-10(a)(2) of Regulation S-X. RSC issued a report on our proved reserves at December 31, 2019, 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 international experience that contribute to our internal reserve and resource estimates. This team works closely with our independent petroleum engineers to ensure the integrity, accuracy and timeliness of data furnished in their reserve and resource estimation process. Our Reservoir Engineering team is responsible for overseeing the preparation of our reserves estimates and has over 100 combined years of industry experience among them with positions of increasing responsibility in engineering and evaluations. Each member of our team holds a minimum of a Bachelor of Science degree in petroleum engineering or geology.

The 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 18 years of practical experience in petroleum engineering. He graduated from University of California at Berkeley in 2000 with Bachelor of Science Degrees in Chemical Engineering and Material Science Engineering, and he received a Master of Science degree in Petroleum Engineering from University of Southern California in 2007. Mr. Famurewa meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

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

Gross and Net Undeveloped and Developed Acreage

The following table sets forth certain information regarding the developed and undeveloped portions of our license and lease areas as of December 31, 2019 for the countries in which we currently operate.

	Developed Area (Acres)		Undeveloped Area (Acres)		Total Area (Acres)	
	Gross	Net(1)	Gross	Net(1)	Gross	Net(1)
	(In thousands)					
Ghana(2)	163	32	34	7	197	39
Cote d'Ivoire	—	—	4,143	1,865	4,143	1,865
Equatorial Guinea	65	26	2,355	1,292	2,420	1,318
Mauritania	—	—	4,944	1,383	4,944	1,383
Namibia	—	—	3,039	1,368	3,039	1,368
South Africa	—	—	1,712	770	1,712	770
Sao Tome and Principe(3)	—	—	8,524	3,159	8,524	3,159
Senegal	—	—	2,116	631	2,116	631
Suriname	—	—	2,793	1,142	2,793	1,142
U.S. Gulf of Mexico	92	26	338	211	430	237
Total	320	84	29,998	11,828	30,318	11,912

(1) Net acreage based on Kosmos' participating interests, before the exercise of any options or back-in rights, except for our net acreage associated with the Jubilee, TEN, and Greater Tortue Ahmeyim fields, which are after the exercise of options or back-in rights. Our net acreage in Ghana may be affected by any redetermination of interests in the Jubilee Unit and our net acreage in Mauritania and Senegal may be affected by any redetermination of interests in the Greater Tortue Ahmeyim Unit.

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

(3) Formal withdrawal notice on STP Block 12 was communicated to partners on December 13, 2019 and will be effective January 31, 2020.

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, 2019:

	Productive Oil Wells		Productive Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Ghana	46	10.08	—	—	46	10.08
Equatorial Guinea	82	33.13	—	—	82	33.13
U.S. Gulf of Mexico	21	5.93	—	—	21	5.93
Total(1)	149	49.14	—	—	149	49.14

(1) Of the 149 productive wells, 37 (gross) or 8.70 (net) have multiple completions within the wellbore.

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, 2019														
Ghana	—	—	—	—	—	—	4	0.89	—	—	4	0.89	4	0.89
Equatorial Guinea	—	—	—	—	—	—	—	—	—	—	—	—	—	—
U.S. Gulf of Mexico	2	0.42	1	0.50	3	0.92	2	0.96	—	—	2	0.96	5	1.88
Mauritania	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Senegal	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	2.00	0.42	1	0.50	3	0.92	6	1.85	—	—	6	1.85	9	2.77
Year Ended December 31, 2018														
Ghana	—	—	3	0.80	3	0.80	4	0.89	—	—	4	0.89	7	1.69
U.S. Gulf of Mexico(4)	—	—	—	—	—	—	1	0.55	—	—	1	0.55	1	0.55
Senegal	—	—	1	0.30	1	0.30	—	—	—	—	—	—	1	0.30
Suriname	—	—	2	1.20	2	1.20	—	—	—	—	—	—	2	1.20
Total	—	—	6	2.30	6	2.30	5	1.44	—	—	5	1.44	11	3.74
Year Ended December 31, 2017														
Ghana	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Mauritania	—	—	2	0.56	2	0.56	—	—	—	—	—	—	2	0.56
Total	—	—	2	0.56	2	0.56	—	—	—	—	—	—	2	0.56

(1) As of December 31, 2019, nine 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 16 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) Represents activity from the U.S. Gulf of Mexico after the acquisition date.

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, 2019.

	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	—	—	—	—	—	—	8	1.93
TEN	—	—	—	—	—	—	7	1.19
Equatorial Guinea								
Block S	—	—	—	—	1	0.40	—	—
U.S. Gulf of Mexico								
Oldfield	1	0.40	—	—	—	—	—	—
Mauritania / Senegal								
Mauritania C8	—	—	—	—	2	0.56	—	—
Greater Tortue Ahmeyim Unit	—	—	—	—	3	0.80	1	0.27
Senegal Cayar Profond	—	—	—	—	3	0.90	—	—
Total	1	0.40	—	—	9	2.66	16	3.39

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 December 31, 2019, 105 Bcf of the 200 Bcf of natural gas has been provided.

Significant License Agreements

Below is a discussion concerning the petroleum contracts governing our current drilling and production operations.

Ghana West Cape Three Points Block

As a result of the approval of the GJFFDP by the Ghana Ministry of Energy in October 2017, operatorship for the West Cape Three Points Block, including the Mahogany and Teak discoveries, transferred to Tullow in February 2018 and are now included in the Jubilee Unit. Kosmos is required to pay to the government of Ghana a fixed royalty of 5% and a potential sliding-scale royalty ("additional oil entitlement"), which comes into effect and escalates as the nominal project rate of return increases above a certain threshold. These royalties are to be paid in-kind or, at the election of the government of Ghana, in cash. A corporate tax rate of 35% is applied to profits at a country level.

The WCTP petroleum contract has a duration of 30 years from its effective date (July 2004). However, in July 2011, at the end of the seven-year Exploration Period, parts of the WCTP Block on which we had not declared a discovery area, were not in a development and production area, or were not in the Jubilee Unit, were relinquished ("WCTP Relinquishment Area"). We maintain rights to the Akasa discovery within the WCTP Block as the WCTP petroleum contract remains in effect after the end of the Exploration Period. We and our WCTP Block partners have certain rights to negotiate a new petroleum contract with respect to the WCTP Relinquishment Area. We and our WCTP Block partners, the Ghana Ministry of Energy and GNPC have agreed such WCTP petroleum contract rights to negotiate extend from July 21, 2011 until such time as either a new petroleum contract is negotiated and entered into with us or we decline to match a bona fide third party offer GNPC may receive for the WCTP Relinquishment Area.

Ghana Deepwater Tano Block

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

The DT petroleum contract has a duration of 30 years from its effective date (July 2006). However, in 2013, at the end of the seven-year Exploration Period, parts of the DT Block on which we had not declared a discovery area, were not in a development and production area, or were not in the Jubilee Unit, were relinquished ("DT Relinquishment Area"). Our existing Wawa discovery within the DT Block was not subject to relinquishment upon expiration of the Exploration Period of the DT petroleum contract, as the DT petroleum contract remains in effect after the end of the Exploration Period while commerciality is being determined. Pursuant to our DT petroleum contract, we and our DT Block partners have certain rights to negotiate a new petroleum contract with respect to the DT Relinquishment Area until such time as either a new petroleum contract is negotiated and entered into with us or we decline to match a bona fide third party offer GNPC may receive for the DT Relinquishment Area.

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

Ghana Jubilee Field Unitization

The Jubilee Field, discovered by the Mahogany-1 well in June 2007, 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 remain the same. Our Jubilee Unit interest is 24.1% subject to redetermination of the participating interests pursuant to the terms of the Jubilee UUOA. Our paying interest on development activities is 26.9%.

Greater Tortue Ahmeyim Unitization

The Greater Tortue Ahmeyim Field, discovered by the Tortue-1 well in May 2015, in Mauritania block C8 and by the Guembuel-1 well in January 2016, in the Saint-Louis Offshore Profond Block in Senegal covers an area within both the C8 and Saint-Louis Offshore Profond Blocks. Mauritania and Senegal agreed that the Greater Tortue Ahmeyim Field would be unitized for optimal resource recovery in the Inter-State Cooperation Agreement (ICA) signed in February 2018. The GTA UUOA was agreed between the contractor groups of the C8 and Saint-Louis Offshore Profond Blocks and approved by the appropriate Ministers in Mauritania and Senegal in February 2019. BP Mauritania and BP Senegal are co-Unit Operator and will allocate responsibilities for the initial development of the Greater Tortue Ahmeyim Field. Although the Greater Tortue Ahmeyim Field is unitized, Kosmos' participating interests in each block outside the boundary of the Greater Tortue Ahmeyim Unit remain the same. Our Unit interest is 26.7% 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.

Mauritania Agreements

Effective June 2012, we entered into three petroleum contracts covering offshore Mauritania Blocks C8, C12 and C13 with the Islamic Republic of Mauritania. We provide technical exploration services to BP, the operator. The Mauritanian national oil company, SMHPM, currently has a 10% carried interest during the exploration period only. Should a commercial discovery be made, SMHPM's 10% carried interest is extinguished and SMHPM will have an option to obtain a participating interest between 10% and 14%. SMHPM will pay its portion of development and production costs in a commercial development. Cost recovery oil is apportioned to the contractor from up to 55% (62% for gas) of total production prior to profit oil being split between the government of Mauritania and the contractor. Profit oil is then apportioned based upon "R-factor" tranches, where the R-factor is cumulative net revenues divided by the cumulative investment. At the election of the government of Mauritania, the government may receive its share of production in cash or in kind. A corporate tax rate of 27% is applied to profits at the license level. The terms of exploration periods of these Offshore Blocks are all ten years and initially included a first exploration period of four years followed by the second exploration period of three years and the third exploration period of three years. Kosmos is currently in the third exploration period for Blocks C8 and C12, expiring in June 2022. Kosmos is currently in the second exploration period for Block C13, having received a two year extension, now expiring in June 2021. This extension also reduced the third exploration period for Block C13 from three years to one year. In the event of commercial success, we have the right to develop and produce oil for 25 years and gas for 30 years from the grant of an exploitation authorization from the government, which may be extended for an additional period of 10 years under certain circumstances.

In October 2016, we entered into a petroleum contract covering Block C6 with the Islamic Republic of Mauritania. As a result of a subsequent farm-out, we have a 28% participating interest and provide technical exploration services to BP, the operator. The Mauritanian national oil company, SMHPM, currently has a 10% carried interest during the exploration period. We are currently in the first exploration period, which extends four years from the effective date (October 28, 2016).

Senegal Agreements

In June 2018, we entered the final renewal of the exploration period for the Senegal Cayar Offshore Profond and Saint Louis Offshore Profond Blocks, which lasts for approximately two and one-half years, ending in March 2021 for Cayar Offshore Profond and July 2021 for Saint Louis Offshore Profond. In the event of commercial success, we have the right to develop and produce oil and/or gas for a period of 25 years from the grant of an exploitation authorization from the government, which may be extended on two separate occasions for a period of 10 years each under certain circumstances.

Equatorial Guinea Exploration Agreements

In March 2018, we entered into petroleum contracts covering Blocks EG-21, S, and W with the Republic of Equatorial Guinea. We currently have a 40% interest in the blocks. The Equatorial Guinean national oil company, GEPetrol, currently has a 20% carried participating interest during the exploration period. Should a commercial discovery be made, GEPetrol's 20% carried interest will convert to a 20% participating interest. The petroleum contracts cover approximately 6,000 square kilometers, with a first exploration period of five years from the date of notification of ratification by the President of Equatorial Guinea. The first exploration period consists of two sub-periods of three and two years, respectively, which can be extended up to two additional years at our election, subject to fulfilling specific work obligations. The first exploration sub-period work program includes an approximately 6,000 square kilometer 3D seismic acquisition requirement across the three blocks.

In the first quarter of 2019, we acquired Ophir's remaining interest in and operatorship of Block EG-24 offshore Equatorial Guinea, which results in Kosmos owning an 80% interest in Block EG-24. 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 20% participating interest for all development and production operations. The petroleum contract covers approximately 3,500 square kilometers, with a first exploration sub-period of three years from the effective date (March 2018), which can be extended up to four additional years at our election, subject to fulfilling specific work obligations. The first exploration sub-period work program includes a 3,000 square kilometer 3D seismic acquisition requirement.

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. 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. We do not anticipate entering into any long term sales agreements at this time.

In December 2017, we signed the TAG GSA and we began exporting TEN associated gas to shore in the fourth quarter of 2018. The TAG GSA provides for an inflation-adjusted sales price of $0.50 per mmbtu.

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 production as are the other Ceiba Field partners. We have entered into an agreement with an oil marketing agent to market our share of the Ceiba Field oil, and we approve the terms of each sale proposed by such agent. We do not anticipate entering into any long term sales agreements at this time.

In the U.S. Gulf of Mexico, we sell crude oil to purchasers typically through monthly contracts, with the sale taking place at multiple points offshore, depending on the particular property. Natural gas is sold to purchasers through monthly contracts, with the sale taking place either offshore or at an onshore gas processing plant after the removal of NGLs. We actively market our crude oil and natural gas to purchasers, and sales prices for purchased oil and natural gas volumes are negotiated with purchasers and are based on certain published indices. Since most of the oil and natural gas contracts are month-to-month, there are very few dedications of production to any one purchaser. We sell the NGLs entrained in the natural gas that we produce. The arrangements to sell these products first requires natural gas to be processed at an onshore gas processing plant. Once the liquids are removed and fractionated (broken 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 lease production from the Company's leases offshore.

There are a variety of factors which affect the market for oil, including the proximity and capacity of transportation facilities, demand for oil both within the local market and beyond, the marketing of competitive fuels and the effects of government regulations on oil production and sales. Our revenue can be materially affected by current economic conditions and the price of oil. However, based on the current demand for crude oil and the fact that alternative purchasers are available, we believe that the loss of our marketing agent 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.

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. Dated Brent crude, the benchmark for our international oil sales, ranged from approximately $53 to $75 per barrel during 2019. HLS crude, the benchmark for our U.S. Gulf of Mexico oil sales, which generally trades at a discount to Dated Brent, ranged from approximately $52 to $75 during 2019. Excluding the impact of hedges, our realized price for 2019 was $63.25 per barrel. We believe lower prices will generally result in greater availability of assets and necessary equipment. However, the impacts on the industry from a competitive perspective are not entirely known.

Title to Property

Other than as specified in this annual report on Form 10-K, 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 of various permits before operations commence or for operations to continue;
- enjoin some or all of the operations or facilities deemed not in compliance with 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;
- 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 cannot assure you that we have been or will be at all times in compliance with such laws, or that environmental laws and regulations will not change or become more stringent in the future in a manner that could have a material adverse effect on our financial condition and results of operations.

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

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

Capping and Containment (Excluding the U.S. Gulf of Mexico)

We entered into an agreement with a third party service provider for it to supply subsea capping and containment equipment on a global basis (excluding the U.S. Gulf of Mexico). 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. We also developed an emergency response plan and response organization to prepare and demonstrate our readiness to respond to a subsea well control incident. Capping and containment for the U.S. Gulf of Mexico is detailed in the U.S. Gulf of Mexico (Operated and Non-operated) section below.

Oil Spill Response

To complement our agreement discussed above for subsea capping and containment equipment, we became a charter member of the Global Dispersant Stockpile ("GSD"). The dispersant stockpile, which is managed by Oil Spill Response Limited ("OSRL") of Southampton, England, an oil spill response contractor, consists of 5,000 cubic meters of dispersant strategically located at OSRL bases around the world. The total volume of the stockpile located at the OSRL bases is calculated to provide members with the ability to respond to a major spill incident. Dispersant from the GSD can be used in the U.S. Gulf of Mexico.

Mauritania and Senegal (Non-operated)

Kosmos transferred operatorship of Mauritania and Senegal operations to BP at the beginning of 2018 and was not the operator for any operations during 2019.

Ghana (Non-operated)

Tullow, our partner and the operator of the Jubilee Unit and the TEN fields, maintains Oil Spill Contingency Plans ("OSCP") covering the Jubilee Field and Deepwater Tano Block. Under the OSCPs, emergency response teams may be activated to respond to oil spill incidents. Tullow has access to OSRL's oil spill response services comprising technical expertise and assistance, including access to response equipment and dispersant spraying systems. Tullow maintains lease agreements with OSRL for Tier 1 and Tier 2 packages of oil spill response equipment.

Equatorial Guinea (Operated and Non-operated)

Effective January 1, 2019, Trident became operator of the Ceiba Field and Okume Complex. In addition, Kosmos drilled an exploration well in 2019 after joining the Equatorial Guinea Oil and Gas Operators Emergency Resource Allocation Agreement to share equipment with other in country operators in case of emergency. Our membership in OSRL provided access to Tier II and III equipment located in Accra, Ghana and Southampton, UK.

Sao Tome and Principe (Operated and Non-operated)

Kosmos plans on drilling an exploration well offshore Sao Tome and Principe and began the Oil Spill Contingency Planning process in 2019. Kosmos is also supporting the government of Sao Tome and Principe with the development of their National Oil Spill Contingency Plan to enable them to access the International Oil Pollution Compensation Funds to respond to third party incidents.

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

After the major well control incident and oil release in the U.S. Gulf of Mexico in 2010, the U.S. Department of Interior updated regulations which govern the type, amount and capabilities of response equipment that needs to be available to operators to respond to similar incidents. These regulations also dictate the type and frequency of training that operating personnel need to receive and demonstrate proficiency in. Kosmos also has an Oil Spill Response Plan ("OSRP") which is approved by the Bureau of Safety and Environmental Enforcement ("BSEE"). This OSRP would be activated if needed in the event of an oil spill or containment event in the U.S. Gulf of Mexico. Kosmos joined several cooperatives that were established to meet the requirements of the new regulations. For capping and containment, Kosmos joined the Helix Well Containment Group ("HWCG") consortium whose capabilities include; (i) two dual ram capping stacks rated at 15,000 psi and 10,000 psi respectively, (ii) intervention equipment to cap and contain a well with the mechanical and structural integrity to be shut in at depths up to 10,000 feet, and (iii) the ability to capture and process 130,000 barrels of fluid per day and 220 Mcf of gas per day. Kosmos is also a member of the Clean Gulf Associate ("CGA") Oil Spill Cooperative, which provides oil spill response capabilities to meet regulatory requirements. Equipment and services include a High Volume Open Sea Skimming System ("HOSS"), dedicated oil spill response vessels strategically positioned along the U.S. gulf coast, dispersant 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.

Employees

As of December 31, 2019, we had approximately 360 employees. None of these employees are represented by labor unions or covered by any collective bargaining agreement. We believe that relations with our employees are satisfactory.

Corporate Information

On December 28, 2018, we changed our jurisdiction of incorporation from Bermuda to the State of Delaware, USA. Kosmos Energy Ltd. discontinued as a Bermuda exempted company pursuant to Section 132G of the Companies Act 1981 of Bermuda and, pursuant to Section 265 of the General Corporation Law of the State of Delaware (the “DGCL”), continued its existence under the DGCL as a corporation organized in the State of Delaware. This transaction is referred to as the “Redomestication”. The business, assets and liabilities of the Company and its subsidiaries on a consolidated basis, as well as its principal locations and fiscal year, were the same immediately after the Redomestication as they were immediately prior to the Redomestication. In addition, the directors and executive officers of the Company immediately after the Redomestication were the same individuals who were directors and executive officers, respectively, of the Company immediately prior to the Redomestication.

The Company did not change its name in connection with the Redomestication. In the Redomestication, each of the outstanding common shares of Kosmos Energy Ltd., an exempted company incorporated pursuant to the laws of Bermuda, were automatically converted by operation of law, on a one-for-one basis, into shares of common stock of Kosmos Energy Ltd., a company incorporated pursuant to the laws of Delaware. Consequently, each holder of a Kosmos Energy Ltd. common share now holds a share of Kosmos Energy Ltd.'s common stock in each case representing the same proportional equity interest in the Company as that shareholder held prior to the Redomestication. The number of shares of the Company's common stock outstanding immediately after the Redomestication was the same as the number of common shares of Kosmos Energy Ltd. outstanding immediately prior to the Redomestication. In connection with the Redomestication, the Company adopted a new certificate of incorporation, bylaws and form of common stock certificate, copies of which are filed herewith as Exhibits 3.1, 3.2 and 4.1, respectively.

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.

Risks Relating to the Oil and Natural Gas Industry and Our Business

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

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

The deepwater offshore Mauritania and Senegal, an area in which we currently focus a substantial amount of our development efforts, has only recently been considered economically viable for hydrocarbon production due to the costs and difficulties involved in drilling and development at such depths and the relatively recent discovery of commercial quantities of hydrocarbons in the region. Likewise, our deepwater offshore Cote d'Ivoire, Namibia, Sao Tome and Principe, South Africa and Suriname licenses have not yet proved to be economically viable production areas. 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.

In this report we provide 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 a tightening in the supply of various types of oilfield equipment and related services or unanticipated geologic conditions.

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 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 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 operations may be adversely affected by political and economic circumstances in the countries 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 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 decrease or operating or development costs increase.

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

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

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

The prices that we will receive for our oil and natural gas will significantly affect our revenue, profitability, access to capital and future growth rate. Historically, the oil and natural gas markets have been volatile and will likely continue to be volatile in the future. Oil prices experienced significant and sustained declines in the past few years and will likely continue to be volatile in the future. The prices that we will receive for our production and the levels of our production depend on numerous factors. These factors include, but are not limited to, the following:

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

Lower oil prices may not only reduce our revenues but also may limit the amount of oil that we can produce economically. A substantial or extended decline in oil and natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Under the terms of our various 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.

In order to protect our exploration and production rights in our license areas, we must meet various drilling and declaration requirements. In general, unless we make and declare discoveries within certain time periods specified in our various 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 these 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, 2019, we have unfulfilled drilling obligations in one of our Mauritania petroleum contracts. In certain other petroleum contracts, we are in the initial exploration phase, 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 each of the WCTP and DT petroleum contracts has expired. Pursuant to the terms of such petroleum contracts, while we and our respective block partners have certain rights to negotiate new petroleum contracts with respect to the WCTP Relinquishment Area and DT Relinquishment Area, we cannot assure you that we will determine to enter any such new petroleum contracts. 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 are unable to meet their commitments under such agreements. We are currently exposed to credit risk through joint interest receivables from our block and/or unit partners. If any of our partners in the blocks or unit in which we hold interests are unable to fund their share of the exploration and development 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 joint operating 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 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 the third parties we contract with 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, which we currently sell to an oil marketing company, and to cover our commodity derivatives contracts. The inability or failure of our significant customers or counterparties to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. In addition, our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. Joint interest receivables arise from our block partners. The inability or failure of third parties we contract with to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. We are unable to predict sudden changes in creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited and we could incur significant financial losses.

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

The interests in and development of the Jubilee Field are governed by the terms of the Jubilee UUOA. The parties to the Jubilee UUOA, the collective interest holders in each of the WCTP and DT Blocks, initially agreed that interests in the Jubilee Unit will be shared equally, with each block deemed to contribute 50% of the area of such unit. The respective interests in the Jubilee Unit were therefore initially determined by the respective interests in such contributed block interests. Pursuant to the terms of the Jubilee UUOA, the percentage of such contributed interests is subject to a process of redetermination once sufficient development work has been completed in the unit. The initial redetermination process was completed on October 14, 2011. As a result of the initial redetermination process, the tract participation was determined to be 54.4% for the WCTP Block and 45.6% for the DT Block. Our Unit Interest (participating interest in the Jubilee Unit) was increased from 23.5% to 24.1%. 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, Ceiba and Okume, the Greater Tortue Ahmeyim Unit or certain producing fields in the U.S. Gulf of Mexico and do not hold operatorship in certain other offshore blocks. In addition, our agreements with BP and Chevron contemplate that operatorship will be transitioned fully to these companies in our Cote d'Ivoire (BP) and Suriname (Chevron) acreage upon a commercial discovery. As a result, we may have limited ability to exercise influence over the operations of the discoveries or prospects operated by our block or unit partners, or which are not wholly-owned by us, as the case may be. Dependence on block or unit partners could prevent us from realizing our target returns for those discoveries or prospects. Further, because we do not have majority ownership in all of our properties, we may not be able to control the timing, or the scope, of exploration or development activities or the amount of capital expenditures and, therefore, may not be able to carry out one of our key business strategies of minimizing the cycle time between discovery and initial production. The success and timing of exploration and development activities will depend on a number of factors that will be largely outside of our control, including:

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

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

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

The process of estimating oil and natural gas reserves is technically complex. It requires interpretations of available technical data and many assumptions, including those relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this report. See “Item 1. Business—Our Reserves” for information about our estimated oil and natural gas reserves and the present value of our net revenues at a 10% discount rate (“PV-10”) and Standardized Measure of discounted future net revenues (as defined herein) as of December 31, 2019.

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

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

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

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

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

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

We 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.

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, strategic alliances or future private or public equity offerings if our cash flows from operations, or the timing of, are not sufficient to cover such costs.

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

- the scope, rate of progress and cost of our exploration, appraisal, development and production activities;
- the success of our exploration, appraisal, development and production activities;
- oil and natural gas prices;
- our ability to locate and acquire hydrocarbon reserves;
- our ability to produce oil or natural gas from those reserves;
- the terms and timing of any drilling and other production-related arrangements that we may enter into;

- the cost and timing of governmental approvals and/or concessions; and
- the effects of competition by other companies operating in the oil and gas industry.

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

Assuming we are able to commence exploration, appraisal, development and production activities or successfully exploit our licenses during the exploratory term, our interests in our licenses (or the development/production area of such licenses as they existed at that time, as applicable) could extend beyond the term set for the exploratory phase of the license to a fixed period or life of production, depending on the jurisdiction. If we are unable to meet our well commitments and/or declare commerciality of the prospective areas of our licenses during this time, we may be subject to significant potential forfeiture of all or part of the relevant license interests. If we are not successful in raising additional capital, we may be unable to continue our exploration and production activities or successfully exploit our license areas, and we may lose the rights to develop these areas. See "—Under the terms of our various license agreements, 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 declare any discoveries and thereby establish development areas 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."

All of our proved reserves, oil production and cash flows from operations are currently associated with our licenses offshore Ghana, Equatorial Guinea, and U.S. Gulf of Mexico. Should any event occur which adversely affects such proved reserves, oil 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 as a result of decreases in oil and natural gas prices, and such decreases could result in reduced availability under our corporate revolver and commercial debt facility.

We capitalize costs to acquire, find and develop our oil and natural gas properties under the successful efforts accounting method. Under such method, we are required to perform impairment tests on our assets periodically and whenever events or changes in circumstances warrant a review of our assets. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of appraisal and development plans, production data, oil and natural gas prices, economics and other factors, we may be required to write down the carrying value of our oil and natural gas assets. A write-down constitutes a non-cash charge to earnings. As a result of the recent drop in oil and natural gas prices, we may incur future write-downs and charges should prices remain at low levels.

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

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

In Ghana, we currently produce associated gas from the Jubilee and TEN fields. A gas pipeline from the Jubilee Field has been constructed to transport such natural gas for processing and sale. However, we granted the Government of Ghana the first 200 Bcf of natural gas exported from the Jubilee Field to shore at zero cost. Through December 31, 2019, the Jubilee partners have provided approximately 105 Bcf from the Jubilee Field to Ghana. Thus, in Ghana, it is forecasted to be a few years before we are able to commercialize the Jubilee Field natural gas. We do not currently book proved gas reserves associated with natural gas sales from the Jubilee Field in Ghana. However, we expect to book gas reserves upon finalization and execution of a gas sales agreement for such Jubilee Field natural gas that will have a price associated with it. A gas pipeline from the TEN fields to the Jubilee Field was completed in the first quarter of 2017 to transport associated natural gas as well as non-associated natural gas for processing and sale. We finalized the TAG GSA, and as a result, we booked proved gas reserves for the associated natural gas from the TEN fields in Ghana. If and when a gas sales agreement and the related infrastructure are in place for the TEN fields non-associated gas, a portion of the remaining gas may be recognized as reserves.

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

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

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

Additionally, the future exploitation and sale of associated and non-associated natural gas and liquids and LNG will be subject to timely commercial processing and marketing of these products, which depends on the contracting, financing, building and operating of infrastructure by third parties. The Government of Ghana completed the construction and connection of a gas pipeline from the Jubilee Field and the pipeline between the Jubilee and TEN fields to transport such natural gas to the mainland for processing and sale was completed in the first quarter of 2017. However, the uptime of the pipeline and processing facilities in future periods is not known. In the absence of the continuous removal of large quantities of natural gas it is anticipated that we will either need to flare such natural gas in order to maintain crude oil production or reduce crude oil production. If we are unable to resolve potential issues related to the continuous removal of associated natural gas in large quantities, our oil production will be negatively impacted.

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

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

In the event that our currently undeveloped discoveries and prospects are developed and become operational, they may not produce oil and natural gas in commercial quantities or at the costs anticipated, and our projects may cease production, in part or entirely, in certain circumstances. Discoveries may become uneconomic as a result of an increase in operating costs to produce oil and natural gas. 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, health and safety laws and regulations 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 and exploration. 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 tropical storms and hurricanes.

Tropical storms, hurricanes and the threat of tropical storms and hurricanes often result in the shutdown of operations, particularly in the U.S. Gulf of Mexico, as well as operations within the path and the projected path of the tropical storms or hurricanes. In addition, climate change could result in an increase in the frequency and severity of tropical storms, hurricanes or other extreme weather events. Weather events have caused significant disruption to the operations of offshore and coastal facilities in the U.S. Gulf of Mexico region. In the future, during a shutdown period, we may be unable to access well sites and our services may be shut down. Additionally, tropical storms or hurricanes may cause evacuation of personnel and damage to our platforms and other equipment, which may result in suspension of our operations. The shutdowns, related evacuations and damage can create unpredictability in activity and utilization rates, as well as delays and cost overruns, which could have a material adverse effect on our business, financial condition and results of operations.

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

Historically, some oil and natural gas development projects have experienced delays and capital cost increases and overruns due to, among other factors, the unavailability or high cost of drilling rigs and other essential equipment, supplies, personnel and oilfield services, as well as mechanical and technical issues. 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 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 experienced mechanical issues in the Jubilee Field, including failures of its gas and water injection facilities on the FPSO, and the turret bearing issue on the FPSO. The equipment downtime caused by these mechanical issues negatively impacted oil production during the year.

Furthermore, deepwater operations generally, and operations in Africa and South America, 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 and South America 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 disagreements with host governments regarding certain of our rights and responsibilities and may have future disagreements with our host governments.

There can be no assurance that future disagreements will not arise with any host government and/or national oil companies 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.

As an example, multiple discovered fields and a significant portion of our proved reserves are located offshore Ghana. The WCTP petroleum contract, the DT petroleum contract and the Jubilee UUOA cover the two blocks and the Jubilee and TEN fields that form the basis of our current operations in Ghana. Pursuant to these petroleum contracts, most significant decisions, including our plans for development and annual work programs, must be approved by GNPC, the Ghanaian Revenue Authority (the “GRA”), the Petroleum Commission and/or Ghana’s Ministry of Energy. We have previously had disagreements with the Ministry of Energy and GNPC regarding certain of our rights and responsibilities under these petroleum contracts, the 1984 Ghanaian Petroleum Law and the Internal Revenue Act, 2000 (Act 592) (the “Ghanaian Tax Law”). These included disagreements over sharing information with prospective purchasers of our interests, pledging our interests to finance our development activities, potential liabilities arising from discharges of small quantities of drilling fluids into Ghanaian territorial waters, the failure to approve the proposed sale of our Ghanaian assets, assertions that could be read to give rise to taxes or other payments payable under the Ghanaian Tax Law, failure to approve PoDs relating to certain discoveries offshore Ghana and the relinquishment of certain exploration areas on our licensed blocks offshore Ghana. The resolution of certain of these disagreements required us to pay agreed settlement costs to GNPC and/or the government of Ghana.

The geographic locations of our licenses in Africa and South America subject us to an increased 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 South America. 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 and South America 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.

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

Oil and natural gas exploration, development and production activities are subject to political and economic uncertainties (including but not limited to the results of the 2020 U.S. presidential election, changes in energy policies or the personnel administering them), changes in laws and policies governing operations of foreign-based 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 and other risks arising out of foreign 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 to possible changes in such tax laws (or the application thereof), each of which could result in an increase in our tax liabilities. These risks may be higher in the developing countries in which we conduct a majority of our activities, as it is the case in Ghana, where the GRA previously disputed certain tax deductions we had claimed in prior fiscal years' Ghanaian tax returns as non-allowable under the terms of the Ghanaian Petroleum Income Tax Law, as well as non-payment of certain transactional taxes and other payments. We have faced similar tax related disputes with the Senegal Tax Administration.

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

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;
- restrict the movement of funds or limit repatriation of profits;
- lead to U.S. government or international sanctions; or
- limit access to markets for periods of time.

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

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

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

In the U.S. Gulf of Mexico, there have been a series of regulatory initiatives developed and implemented at the federal level to address the direct impact of the incident and to prevent similar incidents in the future. Beginning in 2010 and continuing through the present, the Department of Interior (“DOI”) through the BOEM and the Bureau of Safety and Environmental Enforcement (“BSEE”), has issued a variety of regulations and Notices to Lessees and Operators (“NTLs”), intended to impose additional safety, permitting and certification requirements applicable to exploration, development and production activities in the U.S. Gulf of Mexico. These regulatory initiatives effectively slowed down the pace of drilling and production operations in the U.S. Gulf of Mexico as adjustments were being made in operating procedures, certification requirements and lead times for inspections, drilling applications and permits, and exploration and production plan reviews, and as the federal agencies evolved into their present day bureaus. On April 17, 2015, BSEE published a proposed rule that would impose more stringent standards on blowout preventers (“BOP”). In April 2016, BSEE issued a final version of this rule effective July 2016, though some requirements of the rule have delayed compliance deadlines. The final rule addresses the full range of systems and equipment associated with well control operations, focusing on requirements for BOPs, well design, well control casing, cementing, real-time monitoring and subsea containment. Key features of the well control regulations include requirements for 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. On March 28, 2017, President Trump signed an executive order (the “March 2017 Executive Order”) directing federal agencies to initiate rulemakings to suspend, revise or rescind certain regulations relating to the energy industry as necessary to ensure consistency with the goals of energy independence, economic growth and cost-effective environmental regulation. In response to the March 2017 Executive Order and a subsequent executive order issued by President Trump in April 2017 focusing on offshore energy development, in May 2018, BSEE published a proposal to relax certain requirements of the July 2016 rule. The proposed rule’s comment period expired on August 6, 2018, but a final rule has not yet been published; this rule is likely to be subject to legal challenges.

In addition to the array of new or revised safety, permitting and certification requirements developed and implemented by the DOI in the past few years, there have been a variety of proposals to change existing laws and regulations that could affect offshore development and production, such as, for example, a proposal to significantly increase the minimum financial responsibility demonstration required under the Oil Pollution Act of 1990. To the extent the existing regulatory initiatives implemented and pursued over the past few years or any future restrictions, whether through legislative or regulatory means or increased or broadened permitting and enforcement programs, foster uncertainties or delays in our offshore oil and natural gas development or exploration activities, then such conditions may have a material adverse effect on our business, financial condition and results of operations.

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

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

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

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

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

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

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

We are subject to various international, foreign, federal, state and local health, safety and environmental laws and regulations governing, among other things, the emission and discharge of pollutants into the ground, air or water, the generation, storage, handling, use, transportation and disposal of regulated materials and the health and safety of our employees, contractors and communities in which our assets are located. We are required to obtain environmental permits from governmental authorities for our operations, including drilling permits for our wells. We have not been or may not be at all times in complete compliance with these permits and laws and regulations to which we are subject, and there is a risk such requirements could change in the future or become more stringent. If we violate or fail 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. 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.

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

In addition, we expect continued and increasing attention to climate change issues and emissions of GHGs, including methane (a primary component of natural gas) and carbon dioxide (a byproduct of oil and natural gas combustion). For example, in April 2016, 195 nations, including Ghana, Mauritania, Sao Tome and Principe, Senegal, Suriname and the U.S., signed and officially entered into an international climate change accord (the "Paris Agreement"). The Paris Agreement calls for signatory countries to set their own GHG emissions targets, make these emissions targets more stringent over time and be transparent about the GHG emissions reporting and the measures each country will use to achieve its GHG targets. A long-term goal of the Paris Agreement is to limit global temperature increase to well below two degrees Celsius from temperatures in the pre-industrial era. The Paris Agreement is in effect a successor to the Kyoto Protocol, an international treaty aimed at reducing emissions of GHGs, to which various countries and regions, including Ghana, Mauritania, Sao Tome and Principe, Senegal and Suriname, are parties. In 2012, the Kyoto Protocol was extended by amendment through 2020 in the so-called Doha Amendment (although, as of early January 2020, the Doha Amendment had still not entered into force because it had not yet been ratified by the requisite number of parties). It cannot be determined at this time what effect the Paris Agreement, and any related GHG emissions targets, regulations or other requirements, will have on our business, results of operations and financial condition. It also cannot be determined what impact the U.S.'s announced withdrawal from the Paris Agreement will have on international climate change regulation. This regulatory uncertainty, however, could result in a disruption to our business or operations. The physical impacts of climate change in the areas in which our assets are located or in which we otherwise operate, including through increased 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.

Health, safety and environmental laws 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 face various risks associated with increased activism against oil and gas exploration and development activities.

Opposition toward oil and gas drilling and development 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 regarding safety, human rights, climate change, environmental matters, sustainability, and business practices. Anti-development activists are working to, among other things, delay or cancel certain operations such as offshore drilling and development.

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;
- individuals requesting more analysis and disclosure of environmental and climate change-related risks;

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

Activism worldwide may continue to increase if the Trump administration in the U.S. is perceived to be following, or actually follows, through on President Trump's campaign commitments to promote increased fossil fuel exploration and production in the U.S. 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.

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

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

While we believe we maintain a robust compliance program (including policies, procedures, and controls) and corresponding compliance culture, from time-to-time assertions may be raised, including by media outlets or competitors, related to our operations or assets which, notwithstanding the lack of veracity of such assertions, may attract the interest of regulators or affect the market perception of Kosmos. On June 3, 2019, the BBC *Panorama* broadcast a television program, which included various assertions concerning the Cayar Offshore Profond and Saint Louis Offshore Profond Blocks offshore Senegal in which the Company holds interests, which we believe are inaccurate and misleading. We, BP (block operator) and the Government of Senegal all promptly issued independent statements strongly refuting these assertions. As noted in our statement, Kosmos conducted extensive pre-transaction due diligence, and we believe we acquired our interests in the blocks in compliance with applicable laws. After the program aired, the SEC requested that Kosmos voluntarily provide certain documents related to the blocks. We are cooperating with the SEC's voluntary request for documents to ensure that the SEC has an accurate and complete understanding concerning the history of the blocks.

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. For example, we are not insured against political or terrorism risks. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition and results of operations. Further, even in instances where we maintain adequate insurance coverage, potential delays related to receipt of insurance proceeds as well as delays associated with the repair or rebuilding of damaged facilities could also materially and adversely affect our business, financial condition and results of operations.

We operate in a litigious environment.

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

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

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

We face various risks associated with global populism.

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

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

Market volatility and reduced consumer demand may increase economic uncertainty. Many developed countries are constrained by long term structural government budget deficits and international financial markets and credit rating agencies are pressing for budgetary reform and discipline. This need for fiscal discipline is balanced by calls for continuing government stimulus and social spending as a result of the impacts of the global economic crisis. As major countries implement government fiscal reform, such measures, if they are undertaken too rapidly, could further undermine economic recovery, reducing demand and slowing growth. Impacts of the crisis have spread to China and other emerging markets, which have fueled global economic development in recent years, slowing their growth rates, reducing demand, and resulting in further drag on the global economy.

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 our 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 of capital could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in credit rating. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows available for drilling and place us at a competitive disadvantage. Recent and continuing disruptions and volatility in the global financial markets 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 and natural gas, we have and may in the future enter into derivative arrangements for a portion of our oil and natural gas production, including, but not limited to, puts, collars and fixed-price swaps. In addition, we may in the future, hold swaps designed to hedge our interest rate risk. We do not currently designate any of our derivative instruments as hedges for accounting purposes and record all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Derivative arrangements also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counter-party to the derivative instrument defaults on its contract obligations; or
- there is an increase in the differential between the underlying price and actual prices received in the derivative instrument.

In addition, these types of derivative arrangements may limit the benefit we could receive from increases in the prices for oil and natural gas or beneficial interest rate fluctuations and may expose us to cash margin requirements.

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

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

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

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

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

Certain provisions of the indenture governing the 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 indenture governing the 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, 2019, we had $1.4 billion outstanding and $200.0 million of committed undrawn capacity under our commercial debt facility, subject to borrowing base availability. As of December 31, 2019, we had zero outstanding under the Corporate Revolver and the undrawn availability was $400.0 million. As of December 31, 2019, there were five outstanding letters of credit totaling $3.1 million under the letter of credit facility agreement and $650.0 million principal amount of Senior Notes outstanding. We also currently have, and may in the future incur, significant off balance sheet obligations. In the future, we may incur 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 performance. General economic conditions, risks associated with exploring for and producing oil and natural gas, oil and natural gas prices and financial, business and other factors affect our operations and our future 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 our commercial debt facility, 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 the Senior Notes and commercial debt facility 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 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 or the commercial debt facility. 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 indenture governing the Senior Notes limits the ability of our subsidiaries to incur consensual encumbrances or restrictions on their ability to pay dividends or make other intercompany payments to us, with significant qualifications and exceptions. In addition, the terms of the commercial debt facility limit the ability of the obligors thereunder, including our material operating subsidiaries that hold interests in our assets located offshore Ghana and Equatorial Guinea and their intermediate parent companies to provide cash to us through dividend, debt repayment or intercompany lending. In the event that we do not receive distributions from our subsidiaries, we may be unable to make required principal and interest payments on our indebtedness, including the Senior Notes and commercial debt facility.

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

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

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

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

- diversion of our management’s attention to evaluating, negotiating and integrating significant 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 a significant acquisition, our results of operations may be adversely affected.

The success of a significant acquisition (e.g., our acquisition of DGE) 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.

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

We use derivative instruments to manage our commodity price and interest rate risk. The Commodity Futures Trading Commission ("CFTC") has jurisdiction over derivatives instruments including commodity futures and "swaps" under the Commodity Exchange Act; the SEC has jurisdiction over "security-based swaps" under the federal securities laws. The CFTC's regime is largely in effect, while the SEC's regime for "security-based swaps" largely has not yet come into effect.

Of particular importance to us, the CFTC has the authority to, under certain findings, establish position limits for certain futures, options on futures and swap contracts. Certain bona fide hedging transactions or positions would be exempt from these position limits. The CFTC has proposed rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain energy, metal, and agricultural physical commodities, subject to exceptions for certain bona fide hedging transactions. The CFTC has not yet finalized these regulations; therefore, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest-rate swaps and index credit default swaps for mandatory clearing and exchange trading. The CFTC has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. The application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that the Company uses for hedging.

Derivatives dealers that we transact with will need to comply with new margin and segregation requirements for uncleared swaps and security-based swaps. While it is expected that our uncleared derivatives transactions will not directly be subject to those margin requirements, due to the increased costs to dealers for transacting uncleared derivatives in general, our costs for these transactions may increase.

Federal law may also require the counterparties to our derivative instruments to register with the CFTC and become subject to substantial regulation or even spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. These requirements and others could significantly increase the cost of derivatives contracts (including through requirements to clear swaps and to post collateral, each of which could adversely affect our available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and 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 are also implementing 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. At this time, the impact of such regulations is not clear.

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

A cyber incident could result in information theft, data corruption, operational disruption, and/or financial loss.

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

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

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. A cyber-attack could include gaining unauthorized access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or causing operational disruption, or result in denial-of-service on websites. For example, in 2012, a wave of network attacks impacted Saudi Arabia’s oil industry and breached financial institutions in the U.S. A number of U.S. companies have also been subject to cyber-attacks in recent years resulting in unauthorized access to sensitive information. Certain countries are believed to possess cyber warfare capabilities and are credited with attacks on American companies and government agencies.

Our technologies, systems, networks, and those of our business partners may become the target of cyber-attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. A cyber incident involving our information systems and related infrastructure, or that of our business partners, could disrupt our business plans and negatively impact our operations. Although to date we have not experienced any significant cyber-attacks, there can be no assurance that we will not be the target of cyber-attacks in the future or suffer such losses related to any cyber-incident. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

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

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

An epidemic of the Ebola virus disease occurred in parts of West Africa in 2014 and continued through 2015. A substantial number of deaths were reported by the World Health Organization (“WHO”) in West Africa, and the WHO declared it a global health emergency. It is impossible to predict the effect and potential spread of new outbreaks of the Ebola virus in West Africa and surrounding areas. Should another Ebola virus outbreak occur, including to the countries in which we operate, or not be satisfactorily contained, our exploration, development and production plans for our operations could be delayed, or interrupted after commencement. Any changes to these operations could significantly increase costs of operations. Our operations require contractors and personnel to travel to and from Africa as well as the unhindered transportation of equipment and oil and gas production (in the case of our producing fields). Such operations also rely on infrastructure, contractors and personnel in Africa. If travel bans are implemented or extended to the countries in which we operate, or contractors or personnel refuse to travel there, we could be adversely affected. If services are obtained, costs associated with those services could be significantly higher than planned which could have a material adverse effect on our business, results of operations, and future cash flow. In addition, should an Ebola 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.

The ongoing coronavirus outbreak emanating from China at the beginning of 2020 has resulted in increased travel restrictions and extended shutdown of certain businesses in the region. These or any further political or governmental developments or health concerns in China or other countries could result in social, economic and labor instability. These uncertainties could have a material impact on our business operations and financial condition.

Changes in the method of determining London Interbank Offered Rate (“LIBOR”), or the replacement of LIBOR with an alternative reference rate, may adversely affect interest expense related to outstanding debt.

On July 27, 2017, the Financial Conduct Authority in the United Kingdom announced that it would no longer persuade or compel panel banks to submit the rates required to calculate LIBOR after the end of 2021. The announcement indicates that the continuation of LIBOR on the current basis cannot and will not be guaranteed after 2021. The continued existence of LIBOR after 2021, therefore, remains highly uncertain. While various governmental working groups are pursuing replacement rates, if LIBOR ceases to exist, we may need to renegotiate our Facility and Corporate Revolver and may not be able to do so on terms that are favorable to us.

Risks Relating to Our Common Stock

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

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

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

A substantial portion of our total issued and outstanding common stock may be sold into the market at any time. This could cause the market price of our common stock to drop significantly, even if our business is doing well.

All of the shares sold in our initial public offering are freely tradable without restrictions or further registration under the federal securities laws, unless purchased by our "affiliates" as that term is defined in Rule 144 under the Securities Act of 1933, as amended (the "Securities Act"). Substantially all of the remaining shares of common stock are restricted securities as defined in Rule 144 under the Securities Act (unless they have been sold pursuant to Rule 144 to date). Restricted securities may be sold in the U.S. public market only if registered or if they qualify for an exemption from registration, including by reason of Rule 144 or Rule 701 under the Securities Act. All of our restricted shares are eligible for sale in the public market, subject in certain circumstances to the volume, manner of sale limitations with respect to shares held by our affiliates and other limitations under Rule 144. Additionally, we have registered all our shares of common stock that we may issue under our employee benefit plans. These shares can be freely sold in the public market upon issuance, unless pursuant to their terms these share awards have transfer restrictions attached to them. Sales of a substantial number of shares of our common stock, or the perception in the market that the holders of a large number of shares intend to sell common stock, could reduce the market price of our common stock.

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

We may issue additional 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 shares to our executive officers, employees and independent directors as part of their compensation. If we issue additional 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 2. Properties

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

Item 3. Legal Proceedings

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

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Common Stock Trading Summary

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

As of February 19, 2020, 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 55. On February 19, 2020, the last reported sale price of Kosmos' common stock, as reported on the NYSE, was $5.22 per share.

We began paying quarterly cash dividends of $0.0452 per common share in March 2019. Certain of our subsidiaries are currently restricted in their ability to pay dividends to us pursuant to the terms of the Senior Notes, the Facility and the Corporate Revolver unless we meet certain conditions, financial and otherwise. 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.

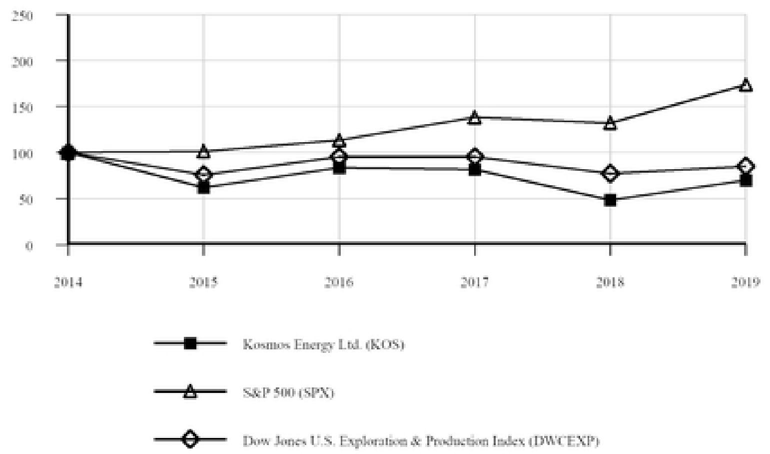
Issuer Purchases of Equity Securities

Under the terms of our LTIP, we have issued restricted shares to our employees. On the date that these restricted shares 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 award agreements and the LTIP, at either the number of vested shares (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. The Company may repurchase the restricted shares sold by the grantees to settle their tax liability. The repurchased shares are reallocated to the number of shares available for issuance under the LTIP. During 2019, there were no shares purchased.

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, 2019, 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,					
	2014	2015	2016	2017	2018	2019
Kosmos Energy Ltd. (KOS)	$ 100.00	$ 61.98	$ 83.55	$ 81.64	$ 48.51	$ 70.01
S&P 500 (SPX)	100.00	101.37	113.49	138.26	132.19	173.80
Dow Jones U.S. Exploration & Production Index (DWCEXP)	100.00	75.80	95.28	95.55	77.11	85.05

Item 6. Selected Financial Data

The following selected consolidated financial information set forth below as of and for the five years ended, December 31, 2019, should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data."

Consolidated Statements of Operations Information:

	Years Ended December 31,				
	2019	2018	2017	2016	2015
	(In thousands, except per share data)				
Revenues and other income:					
Oil and gas revenue	$ 1,499,416	$ 886,666	$ 578,139	$ 310,377	$ 446,696
Gain on sale of assets	10,528	7,666	—	—	24,651
Other income, net	(35)	8,037	58,697	74,978	209
Total revenues and other income	1,509,909	902,369	636,836	385,355	471,556
Costs and expenses:					
Oil and gas production	402,613	224,727	126,850	119,367	105,336
Facilities insurance modifications, net	(24,254)	6,955	(820)	14,961	—
Exploration expenses	180,955	301,492	216,050	202,280	156,203
General and administrative	110,010	99,856	68,302	87,623	136,809
Depletion, depreciation and amortization	563,861	329,835	255,203	140,404	155,966
Interest and other financing costs, net	155,074	101,176	77,595	44,147	37,209
Derivatives, net	71,885	(31,430)	59,968	48,021	(210,649)
(Gain) loss on equity method investments, net	—	(72,881)	6,252	—	—
Other expenses, net	24,648	(6,501)	5,291	23,116	5,246
Total costs and expenses	1,484,792	953,229	814,691	679,919	386,120
Income (loss) before income taxes	25,117	(50,860)	(177,855)	(294,564)	85,436
Income tax expense (benefit)	80,894	43,131	44,937	(10,784)	155,272
Net loss	$ (55,777)	$ (93,991)	$ (222,792)	$ (283,780)	$ (69,836)
Net loss per share:					
Basic	$ (0.14)	$ (0.23)	$ (0.57)	$ (0.74)	$ (0.18)
Diluted	$ (0.14)	$ (0.23)	$ (0.57)	$ (0.74)	$ (0.18)
Weighted average number of shares used to compute net loss per share:					
Basic	401,368	404,585	388,375	385,402	382,610
Diluted	401,368	404,585	388,375	385,402	382,610
Dividends declared per common share	$ 0.1808	$ —	$ —	$ —	$ —

Consolidated Balance Sheets Information:

	December 31,				
	2019	2018	2017	2016	2015
	(In thousands)				
Cash and cash equivalents	$ 224,502	$ 173,515	$ 233,412	$ 194,057	$ 275,004
Total current assets	566,557	509,700	533,602	475,187	734,148
Total property and equipment, net	3,642,332	3,459,701	2,317,828	2,708,892	2,322,839
Total other assets	108,343	118,788	341,173	157,386	146,063
Total assets	4,317,232	4,088,189	3,192,603	3,341,465	3,203,050
Total current liabilities	539,101	384,308	428,730	370,025	456,741
Total long-term liabilities	2,936,429	2,762,403	1,866,761	1,890,241	1,420,796
Total shareholders' equity	841,702	941,478	897,112	1,081,199	1,325,513
Total liabilities and shareholders' equity	4,317,232	4,088,189	3,192,603	3,341,465	3,203,050

Consolidated Statements of Cash Flows Information:

	Years Ended December 31,				
	2019	2018	2017	2016	2015
	(In thousands)				
Net cash provided by (used in):					
Operating activities	$ 628,150	$ 260,491	$ 236,617	$ 52,077	$ 440,779
Investing activities	(363,931)	(985,138)	(152,565)	(537,763)	(796,433)
Financing activities	(220,489)	605,277	(52,261)	448,019	79,634

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

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

Overview

Kosmos is a full-cycle deepwater independent oil and gas exploration and production company focused along the Atlantic Margins. Our key assets include production offshore Ghana, Equatorial Guinea and U.S. Gulf of Mexico, as well as a world-class gas development offshore Mauritania and Senegal. We also maintain a sustainable exploration program balanced between proven basin infrastructure-led exploration (Equatorial Guinea and U.S. Gulf of Mexico), emerging basins (Mauritania, Senegal and Suriname) and frontier basins (Cote d'Ivoire, Namibia, Sao Tome and Principe, and South Africa).

Recent Developments

Corporate

During April 2019, the Company issued $650 million of 7.125% Senior Notes due 2026 and received net proceeds of approximately $640.0 million after deducting commission and deferred financing costs. We used the net proceeds to fund the redemption of our 7.875% Senior Secured Notes due 2021, of which there was a $525 million aggregate principal amount outstanding, to repay a portion of the outstanding indebtedness under our Corporate Revolver and to pay fees and expenses related to the redemption, repayment and the offering.

Ghana

Jubilee

During the year ended December 31, 2019, Jubilee production averaged approximately 87,400 Bopd (gross), as one new producer well came online. During the first quarter of 2019, gas reliability issues were worked on by the operator with the reliability of the gas system enhanced by having a spare high-pressure compressor made available. However, oil production rates remain constrained by gas handling capabilities. Work to enhance gas handling capacity has been deferred by the operator to first quarter of 2020.

TEN

During the year ended December 31, 2019, TEN production averaged approximately 61,100 Bopd (gross) as one new producer well at Enyenra came online. During the second quarter of 2019, the completion of the Enyenra-14 production well was deferred due to operational issues. As a result, the accompanying Enyenra-16 water injection well was also deferred.

U.S. Gulf of Mexico

During the year ended December 31, 2019, U.S. Gulf of Mexico production averaged approximately 24,100 Boepd (net) (~82% oil).

During the first quarter of 2019, the Helix Producer I, the facility that supports production from the Company's Tornado field, completed its planned, regulatory-required dry-dock period. After approximately two months of downtime, production from the Tornado wells re-commenced as scheduled. Early in the second quarter of 2019, the Tornado-3 development well located in Green Canyon block 281 (35.0% working interest) came online.

During the first quarter of 2019, Kosmos farmed-into 18 BP-owned blocks in the Garden Banks area of the deepwater U.S. Gulf of Mexico. In addition, Kosmos can earn an interest in three BP blocks in other areas of the deepwater U.S. Gulf of Mexico. This should allow Kosmos to execute projects that can be tied back to existing infrastructure. Kosmos is the designated operator and drilled the first well in Garden Banks block 492 (Kosmos 50%, BP 50%), the Resolution exploration well, in November 2019. The well encountered reservoir quality sands; however, the primary exploration objective proved to be water bearing. The well was plugged and abandoned and the well results are being integrated into the ongoing evaluation of the surrounding area.

During the first quarter of 2019, Kosmos executed a farm-in agreement with Chevron covering the right to earn an interest in Mississippi Canyon block 728 in the deepwater U.S. Gulf of Mexico. This agreement allows Kosmos another opportunity to execute its deepwater U.S. Gulf of Mexico strategy of infrastructure-led exploration. In the fourth quarter of 2019, Kosmos then entered into a cross assignment of our interest in Mississippi Canyon block 728 with Hess Corporation on their interest in an adjacent block, Mississippi Canyon block 684, after which Kosmos now has a 40% interest in the two blocks, and Hess Corporation has a 60% interest. Kosmos is the designated operator and drilled the first well in Mississippi Canyon block 728, the Oldfield exploration well, in December 2019. The well did not encounter commercial quantities of hydrocarbons and was plugged and abandoned in the first quarter of 2020.

In the second quarter of 2019, we announced the Gladden Deep exploration well located in Mississippi Canyon Block 800 (20.0% working interest) made an oil discovery. Gladden Deep is a subsea tieback that was brought online in September 2019 through the existing Gladden pipeline to the Medusa SPAR.

In October 2019, we drilled the Moneypenny prospect, which was unsuccessful. The well was designed as an inexpensive exploration tail of an Odd Job development well.

Kosmos participated in the U.S. Gulf of Mexico Federal Lease Sales 252 and 253 and was ultimately awarded 13 deepwater blocks during 2019. As part of the Company's strategy to expand its position in the U.S. Gulf of Mexico, these new leases have added significant infrastructure-led exploration prospects to our portfolio.

Equatorial Guinea

Effective January 1, 2019, our outstanding shares in KTIPI were transferred to Trident in exchange for a 40.4% undivided interest in the Ceiba Field and Okume Complex. As a result, our interest in the Ceiba Field and Okume Complex will be accounted for under the proportionate consolidation method of accounting going forward. Pre-tax income from our interests in our Ceiba Field and Okume Complex are taxable in Equatorial Guinea at a 35% statutory tax rate, which will impact our overall effective tax rate.

Production in Equatorial Guinea averaged approximately 38,300 Bopd (gross) for the year ended December 31, 2019. Our ESP program is supporting field production with five ESPs completed during the year ended December 31, 2019.

In March 2019, we acquired Ophir's remaining interest in Block EG-24 offshore Equatorial Guinea, which resulted in Kosmos owning an 80% participating interest and operatorship in the block.

In October 2019, the S-5 exploration well was drilled to a total depth of 4,400 meters offshore Equatorial Guinea, encountering 39 meters of net oil pay in good-quality Santonian reservoir. The well is located within tieback range of the Ceiba FPSO and work is currently ongoing to establish the scale of the discovered resource and evaluate the optimum development solution.

Mauritania and Senegal

Greater Tortue Ahmeyim Unit

In February 2019, to optimize resource recovery in this field, we entered into the GTA UUOA with the governments of Mauritania and Senegal. 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. Mauritania and Senegal each issued an exploitation authorization for the Greater Tortue Ahmeyim Unit area covered by the GTA UUOA. Kosmos and BP signed Carry Advance Agreements with the national oil companies of Mauritania and Senegal, which obligate us separately to finance the respective national oil company’s share of certain development costs incurred through first gas for Phase 1, currently projected in the first half of 2022. Kosmos’ total share for the two agreements combined is up to $239.7 million, which is to be repaid with interest through the national oil companies’ share of future revenues.

In April 2019, KBR was awarded the Pre-FEED services contract for Phases 2 and 3 of the Greater Tortue Ahmeyim project. These next phases are expected to expand capacity of this hub to approximately 10 MMTPA of LNG for export.

During the second quarter of 2019, the national oil companies in Mauritania and Senegal elected to increase their respective interest in their portion of the Greater Tortue Ahmeyim Unit to the maximum allowed percentages under the respective petroleum contracts. After the election, our interest in the exploration areas of Block C8 offshore Mauritania and in Saint Louis Offshore Profound offshore Senegal are unchanged, however, our interest in the Greater Tortue Ahmeyim Unit is now 26.7%.

In the second quarter of 2019, we withdrew from Block C18 offshore Mauritania and we entered into the second exploration phase on blocks C8 and C12 offshore Mauritania, each of which expire in June 2022. Block C12 contains a one well drilling commitment.

In July 2019, we announced the Greater Tortue Ahmeyim-1 (GTA-1) appraisal well was drilled on the eastern anticline within the unit development area of the Greater Tortue Ahmeyim field. The GTA-1 well encountered approximately 30 meters of net gas pay in high quality Albian reservoir. The well was drilled in approximately 2,500 meters of water, approximately 10 kilometers inboard of the Guembeul-1A and Tortue-1 wells, to a total depth of 4,884 meters.

Senegal

In September 2019, we announced the Yakaar-2 appraisal well was drilled approximately nine kilometers from the Yakaar-1 exploration well and further delineated the southern extension of the field. The Yakaar-2 well encountered approximately 30 meters of net gas pay in similar high-quality Cenomanian reservoir to the Yakaar-1 exploration well. The Yakaar-2 well was drilled in approximately 2,500 meters of water to a total depth of approximately 4,800 meters. The Yakaar and Teranga discoveries are being analyzed as a joint development.

Mauritania

In October 2019, we announced the Orca-1 exploration well, located in Block C-8 offshore Mauritania, made a major gas discovery. The Orca-1 well, which targeted a previously untested Albian play, encountered 36 meters of net gas pay in excellent quality reservoirs. In addition, the well extended the Cenomanian play fairway by confirming 11 meters of net gas pay in a down-structure position relative to the original Marsouin-1 discovery well. The location of the Orca-1 proved the structural and stratigraphic trap. The Orca-1 well was drilled in approximately 2,510 meters of water to a total measured depth of around 5,266 meters. The Bir Allah and Orca discoveries are being analyzed as a joint development.

Sao Tome and Principe

In May 2019, we entered into the second exploration phase on Block 5 offshore Sao Tome and Principe, which contains a one well drilling commitment and expires in May 2021. Galp provided notice of withdrawal at the same time, resulting in an increase in Kosmos participating interest from 45% to 58.8%.

In July 2019, the petroleum contract for Block 11 offshore Sao Tome and Principe was amended to remove any well commitment from the second exploration phase and add a contingent well to the third exploration phase in addition to the existing firm well. We also entered the second exploration phase, which will expire in July 2021.

In November 2019, we entered the second exploration phase of Block 6 offshore Sao Tome and Principe, which will expire in November 2021. We plan to drill an exploration well on Block 6 offshore Sao Tome and Principle, as technical operator of the well, in late 2020.

In November 2019, we completed a farm-out agreement with Shell Sao Tome and Principe B.V. to farmout a 20% participating interest in Block 6 and a 30% participating interest in Block 11, offshore Sao Tome and Principe resulting in our participating interests in Block 6 and 11 being 25% and 35%, respectively. A gain of $10.5 million was recognized as a result of the farm-out.

In December 2019, a formal withdrawal notice from Block 12 offshore Sao Tome and Principe was communicated to partners with and effective date of January 31, 2020.

Namibia

In the second quarter of 2019, we received government approval to enter the second renewal period on Block PEL039 offshore Namibia, which contains a one well drilling commitment. We also received a one year extension to the phase, resulting in a three year period ending in August 2022.

Republic of the Congo

In March 2019, we entered into a petroleum contract covering the offshore Marine XXI block with the Republic of the Congo, subject to governmental approvals. Upon approval, we will hold an 85% participating interest and be the operator. The Congolese national oil company, SPNC, has a 15% carried participating interest during the exploration period. Should a commercial discovery be made, SNPC's 15% carried interest will convert to a participating interest of at least 15%. The petroleum contract covers approximately 2,350 square kilometers, with a first exploration period of four years and includes a work program to acquire and interpret 2,200 square kilometers of 3D seismic. There are two optional exploration phases, each for a period of three years, which are subject to additional work program commitments.

Republic of South Africa

In September 2019, we completed a farm-in agreement with OK Energy to acquire a 45% non-operated interest in the Northern Cape Ultra Deep Block offshore the Republic of South Africa. Shell owns 45% of the Block and is the operator and OK

Energy retained 10%. The petroleum contract covers approximately 6,930 square kilometers at water depths ranging from 2,500 to 3,100 meters. The current exploration phase began in January 2019 and lasts for two years.

Results of Operations

All of our results, as presented in the table below, represent operations from the Jubilee and TEN fields in Ghana, the U.S. Gulf of Mexico (commencing September 14, 2018, the DGE acquisition date), and Equatorial Guinea, which was accounted for as an equity method investment during 2018 and 2017. Certain operating results and statistics for the years ended December 31, 2019 and 2018 are included in the following tables. For a discussion of the year ended December 31, 2018 compared to the year ended December 31, 2017, 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, 2018.

		Year Ended December 31, 2019
		(In thousands, except per volume data)
Sales volumes:		
Oil (MBbl)		23,331
Gas (MMcf)		6,323
NGL (MBbl)		548
Total (MBoe)		24,933
Revenues:		
Oil sales	$	1,475,706
Gas sales		15,599
NGL sales		8,111
Total revenues	$	1,499,416
Average oil sales price per Bbl	$	63.25
Average gas sales price per Mcf		2.47
Average NGL sales price per Bbl		14.80
Average total sales price per Boe		60.14
Costs:		
Oil and gas production, excluding workovers	$	370,962
Oil and gas production, workovers		31,651
Total oil and gas production costs	$	402,613
Depletion, depreciation and amortization	$	563,861
Average cost per Boe:		
Oil and gas production, excluding workovers	$	14.88
Oil and gas production, workovers		1.27
Total oil and gas production costs		16.15
Depletion, depreciation and amortization		22.62
Total oil and gas production costs, depletion, depreciation and amortization	$	38.77

	Year Ended December 31, 2018		
	Kosmos	Equity Method Investment- Equatorial Guinea(1)	Total
	(In thousands, except per volume data)		
Sales volumes:			
Oil (MBbl)	12,673	5,228	17,901
Gas (MMcf)	2,268	—	2,268
NGL (MBbl)	179	—	179
Total (MBoe)	13,230	5,228	18,458
Revenues:			
Oil sales	$ 874,382	$ 360,649	$ 1,235,031
Gas sales	7,101	—	7,101
NGL sales	5,183	—	5,183
Total revenues	$ 886,666	$ 360,649	$ 1,247,315
Average oil sales price per Bbl	$ 69.00	$ 68.98	$ 68.99
Average gas sales price per Mcf	3.13	—	3.13
Average NGL sales price per Bbl	28.96	—	28.96
Average total sales price per Boe	67.02	68.98	67.58
Costs:			
Oil and gas production, excluding workovers	$ 217,818	$ 73,843	$ 291,661
Oil and gas production, workovers	6,909	—	6,909
Total oil and gas production costs	$ 224,727	$ 73,843	$ 298,570
Depletion, depreciation and amortization	$ 329,835	$ 134,983	$ 464,818
Average cost per Boe:			
Oil and gas production, excluding workovers	$ 16.46	$ 14.12	$ 15.80
Oil and gas production, workovers	0.52	—	0.38
Total oil and gas production costs	16.98	14.12	16.18
Depletion, depreciation and amortization	24.93	25.82	25.18
Total oil and gas production costs, depletion, depreciation and amortization	$ 41.91	$ 39.94	$ 41.36

(1) For the year ended December 31, 2018, we have presented our 50% share of the results of operations, including our basis difference which is reflected in depletion, depreciation and amortization. Under the equity method of accounting, we only recognize our share of the net income of KTIPI as adjusted for our basis differential, which is recorded in (Gain) loss on equity method investments, net in the consolidated statement of operations.

	Year Ended December 31, 2017		
	Kosmos	Equity Method Investment-Equatorial Guinea(1)	Total
	(In thousands, except per volume data)		
Sales volumes:			
Oil (MBbl)	10,761	405	11,166
Gas (MMcf)	—	—	—
NGL (MBbl)	—	—	—
Total (MBoe)	10,761	405	11,166
Revenues:			
Oil sales	$ 578,139	$ 27,307	$ 605,446
Gas sales	—	—	—
NGL sales	—	—	—
Total revenues	$ 578,139	$ 27,307	$ 605,446
Average oil sales price per Bbl	$ 53.73	$ 67.42	$ 54.22
Average gas sales price per Mcf	—	—	—
Average NGL sales price per Bbl	—	—	—
Average total sales price per Boe	53.73	67.42	54.22
Costs:			
Oil and gas production, excluding workovers	$ 121,429	$ 7,755	$ 129,184
Oil and gas production, workovers	5,421	—	5,421
Total oil and gas production costs	$ 126,850	$ 7,755	$ 134,605
Depletion, depreciation and amortization	$ 255,203	$ 11,181	$ 266,384
Average cost per Boe:			
Oil and gas production, excluding workovers	$ 11.28	$ 19.15	$ 11.57
Oil and gas production, workovers	0.50	—	0.48
Total oil and gas production costs	11.78	19.15	12.05
Depletion, depreciation and amortization	23.72	27.61	23.86
Total oil and gas production costs, depletion, depreciation and amortization	$ 35.50	$ 46.76	$ 35.91

(1) For the year ended December 31, 2017, we have presented our 50% share of the results of operations from the date of acquisition, November 28, 2017 through December 31, 2017, including our basis difference which is reflected in depletion, depreciation and amortization. Under the equity method of accounting, we only recognize our share of the net income of KTIPI as adjusted for our basis differential, which is recorded in (Gain) loss on equity method investments, net in the consolidated statement of operations.

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, 2019 vs. 2018

	Years Ended December 31, 2019	Years Ended December 31, 2018	Increase (Decrease)
	(In thousands)		
Revenues and other income:			
Oil and gas revenue	$ 1,499,416	$ 886,666	$ 612,750
Gain on sale of assets	10,528	7,666	2,862
Other income, net	(35)	8,037	(8,072)
Total revenues and other income	1,509,909	902,369	607,540
Costs and expenses:			
Oil and gas production	402,613	224,727	177,886
Facilities insurance modifications, net	(24,254)	6,955	(31,209)
Exploration expenses	180,955	301,492	(120,537)
General and administrative	110,010	99,856	10,154
Depletion, depreciation and amortization	563,861	329,835	234,026
Interest and other financing costs, net	155,074	101,176	53,898
Derivatives, net	71,885	(31,430)	103,315
Gain on equity method investments, net	—	(72,881)	72,881
Other expenses, net	24,648	(6,501)	31,149
Total costs and expenses	1,484,792	953,229	531,563
Income (loss) before income taxes	25,117	(50,860)	75,977
Income tax expense	80,894	43,131	37,763
Net loss	$ (55,777)	$ (93,991)	$ 38,214

The results of operations for our equity method investments are presented in "Gain on equity method investments, net." See "Item 8. Financial Statements and Supplementary Data—Note 7—Equity Method Investments" for additional information regarding our equity method investments.

Oil and gas revenue. Oil and gas revenue increased by $612.8 million as a result of the inclusion of a full year of revenue from our U.S. Gulf of Mexico business unit for the period ended December 31, 2019 related to the DGE acquisition, versus 108 days of revenue in the previous year's period. The current year period also benefited from the inclusion of revenue from Equatorial Guinea on a consolidated basis for the year ended December 31, 2019, which was previously accounted for as an equity method investment. The revenue increase from higher sales volumes was impacted by lower oil prices during the year ended December 31, 2019. We sold 23,331 MBbl at an average realized price per barrel of $63.25 in 2019 and 12,673 MBbl at an average realized price per barrel of $69.00 in 2018.

Gain on sale of assets. In November 2019, we closed a farm-out agreement with Shell for Blocks 6 and 11 offshore Sao Tome and Principe. As part of the transaction, we received proceeds in excess of our book basis resulting in a gain of $10.5 million. In August 2018, we closed a farm-out agreement with Trident covering blocks S, W and EG-21 offshore Equatorial Guinea. As part of the transaction, we received proceeds in excess of our book basis resulting in a gain of $7.7 million.

Other income. Other income, net decreased by $8.1 million as we recognized a gain of $8.0 million in 2018 on the exit of the Essaouira Offshore block, located offshore Morocco.

Oil and gas production. Oil and gas production costs increased by $177.9 million during the year ended December 31, 2019 as compared to the year ended December 31, 2018. This is a result of the inclusion of a full year of oil and gas production costs from our U.S. Gulf of Mexico business unit for the period ended December 31, 2019 related to the DGE acquisition, versus 108 days of costs in the previous year's period. The current year was also impacted by the inclusion of production costs from

Equatorial Guinea on a consolidated basis for the year ended December 31, 2019, which was previously accounted for as an equity method investment.

Facilities insurance modifications, net. During the year ended December 31, 2019, we incurred $47.2 million of facilities insurance modification costs associated with the long-term solution to the Jubilee turret bearing issue versus $50.2 million during the year ended December 31, 2018. During the year ended December 31, 2019 and 2018, these costs were offset by $71.5 million of hull and machinery insurance proceeds in 2019 as a result of final settlement of the insurance claim and $43.2 million in 2018.

Exploration expenses. Exploration expenses decreased by $120.5 million during the year ended December 31, 2019, as compared to the year ended December 31, 2018. During the year ended December 31, 2019 we recorded lower unsuccessful well costs of $81.3 million primarily related to U.S. Gulf of Mexico drilling versus the 2018 period costs of $123.2 million primarily related to Suriname drilling and the Wawa-1 and Akasa-1 exploration wells in Ghana, which were previously capitalized as suspended well costs. Additionally, seismic acquisition costs decreased $89.1 million versus the prior period primarily related to activity in the U.S. Gulf of Mexico.

General and administrative. General and administrative costs increased by $10.2 million during the year ended December 31, 2019, as compared to the year ended December 31, 2018. This is primarily a result of having a full year of general and administrative costs from our U.S. Gulf of Mexico business unit during the year ended December 31, 2019 related to the DGE acquisition, versus 108 days of costs in the previous year's period.

Depletion, depreciation and amortization. Depletion, depreciation and amortization increased $234.0 million during the year ended December 31, 2019, as compared with the year ended December 31, 2018. The increase is primarily a result of a full year of depletion and amortization costs associated with the acquired U.S. Gulf of Mexico business unit and the inclusion of the Equatorial Guinea business unit, which was previously accounted for as an equity method investment.

Interest and other financing costs, net. Interest and other financing costs, net increased by $53.9 million primarily a result of an increase in interest expense from an increased outstanding debt balance, the result of the DGE acquisition during the third quarter of 2018, and a $24.8 million loss on extinguishment of debt primarily associated with the refinancing of our senior secured notes recorded during the second quarter of 2019.

Derivatives, net. During the years ended December 31, 2019 and 2018, we recorded a loss of $71.9 million and a gain of $31.4 million, respectively, on our outstanding hedge positions. The gain and loss recorded were a result of changes in the forward curve of oil prices during the respective periods.

Gain on equity method investments, net. During the year ended December 31, 2018 we recognized a $72.9 million gain on our equity method investment in KTIPI. Effective January 1, 2019, our equity method investment in KTIPI was exchanged for a direct interest in the Ceiba Field and Okume Complex, which was accounted for under the proportionate consolidation method of accounting during the year ended December 31, 2019.

Other expenses, net. Other expenses, net increased $31.1 million primarily related to $11.5 million in restructuring charges for employee severance and related benefit costs incurred as part of a corporate reorganization and an $8.7 million indirect tax settlement with tax authorities in Senegal during the year ended December 31, 2019, versus a credit resulting from the recovery of disputed charges of $12.9 million related to the arbitration against Tullow Ghana during 2018.

Income tax expense (benefit). For the year ended December 31, 2019, our overall effective tax rate was impacted by the difference in our 21% U.S. income tax reporting rate and the 35% statutory tax rates applicable to our Ghanaian and Equatorial Guinean operations, non-deductible and non-taxable items associated with our U.S., Ghanaian, and Equatorial Guinean operations, and other losses and expenses, primarily related to exploration operations in tax-exempt jurisdictions or in taxable jurisdictions where we have valuation allowances against our deferred tax assets, and therefore, we do not realize any tax benefit on such losses or expenses. For the year ended December 31, 2018, our overall effective tax rate was impacted by non-deductible and non-taxable items associated with our U.S. and Ghanaian operations and other losses and expenses, primarily related to exploration operations in tax-exempt jurisdictions or in taxable jurisdictions where we have valuation allowances against our deferred tax assets, and therefore, we do not realize any tax benefit on such expenses or losses.

Liquidity and Capital Resources

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

While we are presently in a strong financial position, commodity prices remain volatile and could negatively impact our ability to generate sufficient operating cash flows to meet our funding requirements. To partially mitigate this price volatility, we maintain a hedging program. Our investment decisions are based on longer-term commodity prices based on the nature of our projects and development plans. Also, BP has agreed to partially carry our exploration, appraisal and development program in Mauritania and Senegal up to a contractually agreed cap. Current commodity prices, combined with our hedging program, partner carries and our current liquidity position support our dividend and capital program for 2020.

As such, our 2020 capital budget is based on our exploitation and production plans for Ghana, Equatorial Guinea and the U.S. Gulf of Mexico, our infrastructure-led exploration program in Equatorial Guinea and the U.S. Gulf of Mexico, our appraisal and development activities in our emerging basins and our basin opening exploration across the portfolio.

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

As part of the Facility amendment and restatement process in 2018, the lenders approved a redetermination, setting the total commitments under our Facility at $1.5 billion (effective February 22, 2018) which was increased to $1.7 billion (effective January 31, 2019) after the election to exercise $0.2 billion of additional commitments in the fourth quarter of 2018. The commitments were reduced by $100.0 million to $1.6 billion following the Senior Notes issuance in April 2019. The borrowing base calculation includes value related to the Jubilee, TEN, Ceiba and Okume fields.

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, 2019, 2018 and 2017:

	Years Ended December 31,		
	2019	2018	2017
	(In thousands)		
Sources of cash, cash equivalents and restricted cash:			
Net cash provided by operating activities	$ 628,150	$ 260,491	$ 236,617
Net proceeds from issuance of senior notes	641,875	—	—
Return of investment from KTIPI	—	184,664	—
Borrowings under long-term debt	175,000	1,175,000	200,000
Proceeds on sale of assets	15,000	13,703	222,068
	1,460,025	1,633,858	658,685
Uses of cash, cash equivalents and restricted cash:			
Oil and gas assets	340,217	213,806	140,495
Other property	11,796	7,935	2,858
Acquisition of oil and gas properties	—	961,764	—
Equity method investment	—	—	231,280
Notes receivable from partners	26,918	—	—
Payments on long-term debt	425,000	325,000	250,000
Redemption of senior secured notes	535,338	—	—
Purchase of treasury stock	1,983	206,051	2,194
Dividends	72,599	—	—
Deferred financing costs	2,444	38,672	67
	1,416,295	1,753,228	626,894
Increase (decrease) in cash, cash equivalents and restricted cash	$ 43,730	$ (119,370)	$ 31,791

Net cash provided by operating activities. Net cash provided by operating activities in 2019 was $628.2 million compared with net cash provided by operating activities of $260.5 million in 2018 and $236.6 million in 2017, respectively. The increase in cash provided by operating activities in the year ended December 31, 2019 when compared to the same period in 2018 is primarily a result of the inclusion of a full year of our U.S. Gulf of Mexico business unit during the year ended December 31, 2019 related to the DGE acquisition, which was completed during the third quarter of 2018. It is also the result of the inclusion of operations from Equatorial Guinea on a consolidated basis for the year ended December 31, 2019, which was previously accounted for as an equity method investment. The increase in cash provided by operating activities in the year ended December 31, 2018 when compared to the same period in 2017 is primarily a result of an increase in oil and gas revenue and a decrease in exploration expenses related to the stacked rig costs and rig option cancellation payment, both recorded during the year ended December 31, 2017. These changes were offset by a lack of LOPI proceeds, an increase in unsuccessful well costs and an increase in payments related to derivative cash settlements.

The following table presents our liquidity and financial position as of December 31, 2019:

		December 31, 2019
		(In thousands)
Cash and cash equivalents	$	224,502
Restricted cash		4,844
Senior Notes at par		650,000
Borrowings under the Facility		1,400,000
Drawings under the Corporate Revolver		—
Net debt	$	1,820,654
Availability under the Facility	$	200,000
Availability under the Corporate Revolver	$	400,000
Available borrowings plus cash and cash equivalents	$	824,502

Capital Expenditures and Investments

We expect to incur capital costs as we:

- drill additional wells and execute exploitation activities in Ghana, Equatorial Guinea and in the U.S. Gulf of Mexico;
- execute infrastructure-led exploration efforts in the U.S. Gulf of Mexico and Equatorial Guinea;
- execute appraisal and exploration activities in a number of our exploration license areas; and
- acquire and analyze seismic on existing licenses and purchase seismic over new prospective areas.

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 participating, paying and carried interests in our prospects including disproportionate payment amounts, the costs involved in developing or participating in the development of a prospect, the timing of third-party projects, the availability of suitable equipment and qualified personnel and our cash flows from operations. We also evaluate potential corporate and asset acquisition opportunities to support and expand our asset portfolio which may impact our budget assumptions. These assumptions are inherently subject to significant business, political, economic, regulatory, 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 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.

2020 *Capital Program*

We estimate we will spend approximately $325 - $375 million of capital, excluding amounts related to Mauritania and Senegal, for the year ending December 31, 2020. This capital expenditure budget consists of:

- Approximately 40% related to exploitation and production optimization activities across our Ghana, Equatorial Guinea and U.S. Gulf of Mexico assets

- Approximately 50% related to our infrastructure-led exploration and development activities across Equatorial Guinea and the U.S. Gulf of Mexico

- Approximately 10% related to basin opening exploration efforts across our portfolio

In Mauritania and Senegal we estimate capital expenditures of $250 million based on our current ownership interest, net of any remaining BP carry amounts. We expect to fund this expenditure using proceeds and/or carries received from our farm-down process.

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

Significant Sources of Capital

Facility

In February 2018, the Company amended and restated the Facility with a total commitment of $1.5 billion from a number of financial institutions with additional commitments up to $0.5 billion being available if the existing financial institutions increase their commitments or if commitments from new financial institutions are added. In November 2018, the Company exercised its option with existing financial institutions to provide the Company with an additional commitment of $100 million in the aggregate under the Facility. The borrowing base calculation includes value related to the Jubilee, TEN, Ceiba and Okume fields. The Facility supports our oil and gas exploration, appraisal and development programs and corporate activities. As part of the debt refinancing in February 2018, the repayment of borrowings under the existing facility attributable to financial institutions that did not participate in the amended Facility was accounted for as an extinguishment of debt, and $4.1 million of existing unamortized debt issuance costs and deferred interest attributable to those participants was expensed in interest and other financing costs, net. As of December 31, 2019, we have $32.8 million of unamortized issuance costs related to the Facility, which will be amortized over the remaining term of the Facility. In December 2018, the Company entered into letter agreements with existing financial institutions, which provided the Company with an additional commitment of $100 million in the aggregate under the Facility effective January 31, 2019. This took the total commitments to $1.7 billion as of January 31, 2019. The commitments were reduced by $100.0 million to $1.6 billion following the Senior Notes issuance in April 2019 and remain at $1.6 billion as of December 31, 2019.

As of December 31, 2019, borrowings under the Facility totaled $1.4 billion and the undrawn availability under the Facility was $200.0 million, which includes the additional commitments as referenced above.

Interest is the aggregate of the applicable margin (3.25% to 4.50%, depending on the length of time that has passed from the date the Facility was entered into) and LIBOR. 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 March 31, 2022, outstanding borrowings will be constrained by an amortization schedule. The Facility has a final maturity date of March 31, 2025. As of December 31, 2019, 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. The amount of funds available to be borrowed under the Facility, also known as the borrowing base amount, is determined each year on March 31. 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 Ghana and Equatorial Guinea.

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 contains customary cross default provisions.

We were in compliance with the financial covenants contained in the Facility as of September 30, 2019 (the most recent assessment date), which requires the maintenance of:

- the field life cover ratio (as defined in the glossary), not less than 1.30x; and
- the loan life cover ratio (as defined in the glossary), not less than 1.10x; and
- the debt cover ratio (as defined in the glossary), not more than 3.5x; and
- the interest cover ratio (as defined in the glossary), not less than 2.25x.

Corporate Revolver

In August 2018, we amended and restated the Corporate Revolver maintaining the borrowing capacity at $400.0 million, extending the maturity date from November 2018 to May 2022 and lowering the margin 100 basis points to 5%. This results in lower commitment fees on the undrawn portion of the total commitments, which is 30% per annum of the respective margin. The Corporate Revolver is available for general corporate purposes and for oil and gas exploration, appraisal and development programs.

As of December 31, 2019, there were no borrowings outstanding under the Corporate Revolver and the undrawn availability under the Corporate Revolver was $400.0 million.

Interest is the aggregate of the applicable margin (5.0%), LIBOR and mandatory cost (if any, as defined in the Corporate Revolver). Interest is payable on the last day of each interest period (and, if the interest period is longer than six months, on the dates falling at six-month intervals after the first day of the interest period). We pay commitment fees on the undrawn portion of the total commitments. Commitment fees for the lenders are equal to 30% per annum of the respective margin when a commitment is available for utilization.

The Corporate Revolver expires on May 31, 2022. The available amount is not subject to borrowing base constraints. We have the right to cancel all the undrawn commitments under the Corporate Revolver. We are required to repay certain amounts due under the Corporate Revolver with sales of certain subsidiaries or sales of certain assets. If an event of default exists under the Corporate Revolver, the lenders can accelerate the maturity and exercise other rights and remedies, including the enforcement of security granted pursuant to the Corporate Revolver over certain assets held by us. The Corporate Revolver contains customary cross default provisions.

We were in compliance with the financial covenants contained in the Corporate Revolver as of September 30, 2019 (the most recent assessment date), which requires the maintenance of:

- the debt cover ratio (as defined in the glossary), not more than 3.5x; and
- the interest cover ratio (as defined in the glossary), not less than 2.25x.

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

Revolving Letter of Credit Facility

In July 2013, we entered into a revolving letter of credit facility agreement ("LC Facility"). The size of the LC Facility was $75.0 million, as amended in July 2015, with additional commitments up to $50.0 million being available if the existing lender increased its commitments or if commitments from new financial institutions were added. The LC Facility provides that we shall maintain cash collateral in an amount equal to at least 75% of all outstanding letters of credit under the LC Facility, provided that during the period of any breach of certain financial covenants, the required cash collateral amount shall increase to 100%.

In July 2016, we amended and restated the LC Facility, extending the maturity date to July 2019. Other amendments included increasing the margin from 0.5% to 0.8% per annum on amounts outstanding, adding a commitment fee payable quarterly in arrears at an annual rate equal to 0.65% on the available commitment amount and providing for issuance fees to be payable to the lender per new issuance of a letter of credit. We may voluntarily cancel any commitments available under the LC Facility at any time. During the first quarter of 2017, the LC Facility size was increased to $115.0 million and in April 2017, we reduced the size of our LC Facility to $70 million. In February 2018, the LC Facility was increased to $73 million to facilitate the issuance of additional letters of credit. In July 2018 and December 2018, the LC Facility size was voluntarily reduced to $40.0 million and$20.0 million, respectively, based on the expiration of several large outstanding letters of credit. The LC Facility expired in July 2019, however, as of December 31, 2019, there were five outstanding letters of credit totaling $3.1 million under the LC Facility, which will remain outstanding until the respective letters of credit expire. The LC Facility contains customary cross default provisions.

In 2019, we issued two letters of credit totaling $20.4 million under a new letter of credit arrangement, which does not currently require cash collateral.

7.875% Senior Secured Notes due 2021

In April 2019, all of the Senior Secured Notes were redeemed for $543.8 million, including accrued interest and the early redemption premium. The redemption resulted in a $22.9 million loss on extinguishment of debt, which is included in Interest and other financing costs, net on the Consolidated Statement of Operations.

7.125% Senior Notes due 2026

In April 2019, the Company issued $650.0 million of 7.125% Senior Notes (the "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 Senior Secured Notes, 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 Senior Notes.

The Senior Notes mature on April 4, 2026. We will pay interest in arrears on the Senior Notes each April 4 and October 4, commencing on October 4, 2019. The Senior Notes are senior, unsecured obligations of Kosmos Energy Ltd. and rank equal in right of payment with all of its existing and future senior indebtedness (including all borrowings under the Corporate Revolver) 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 guaranteed on a senior, unsecured basis by certain subsidiaries owning the Company's Gulf of Mexico assets, and on a subordinated, unsecured basis by certain subsidiaries that guarantee the Facility.

At any time prior to April 4, 2022, and subject to certain conditions, the Company may, on one or more occasions, redeem up to 40% of the original principal amount of the Senior Notes with an amount not to exceed the net cash proceeds of certain equity offerings at a redemption price of 107.1% of the outstanding principal amount of the 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 April 4, 2022 the Company may, on any one or more occasions, redeem all or a part of the Senior Notes at a redemption price equal to 100%, plus any accrued and unpaid interest, and plus a “make-whole” premium. On or after April 4, 2022, the Company may redeem all or a part of the Senior Notes at the redemption prices (expressed as percentages of principal amount) set forth below plus accrued and unpaid interest:

Year	**Percentage**
On or after April 4, 2022, but before April 4, 2023	103.6%
On or after April 4, 2023, but before April 4, 2024	101.8%
On or after April 4, 2024 and thereafter	100.0%

We may also redeem the 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 Senior Notes at a price equal to the principal amount of the 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 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 Senior Notes indenture, the Company will be required to make an offer to repurchase the 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 Senior Notes indenture, we will be required to use the net proceeds to make an offer to purchase the Senior Notes at an offer price in cash in an amount equal to 100% of the principal amount of the Senior Notes, plus accrued and unpaid interest to, but excluding, the repurchase date.

The Senior Notes indenture restricts our ability and the ability of our 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 our subsidiaries to make dividends or other payments to us, 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 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.

Contractual Obligations

The following table summarizes by period the payments due for our estimated contractual obligations as of December 31, 2019:

	Payments Due By Year(4)						
	Total	**2020**	**2021**	**2022**	**2023**	**2024**	**Thereafter**
	(In thousands)						
Principal debt repayments(1)	$ 2,050,000	$ —	$ 174,800	$ 284,200	$ 271,600	$ 440,829	$ 878,571
Interest payments on long-term debt(2)	580,098	125,028	116,426	105,812	88,372	71,370	73,090
Operating leases(3)	35,774	3,379	4,201	4,264	4,327	3,491	16,112

(1) Includes the scheduled maturities for the $650.0 million aggregate principal amount of Senior Notes issued in April 2019 and borrowings under the Facility. The scheduled maturities of debt related to the Facility are based on, as of December 31, 2019, 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) Based on outstanding borrowings as noted in (1) above and the LIBOR yield curves at the reporting date and commitment fees related to the Facility and Corporate Revolver and interest on the Senior Notes.

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

(4) 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 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 of Notes to the Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding these liabilities.

We currently have a commitment to drill one exploration well in each of Sao Tome and Principe and Namibia and two exploration wells in Mauritania. In Sao Tome and Principe, we also have 3D seismic acquisition requirements of approximately 13,500 square kilometers. In South Africa, we have 2D seismic acquisition requirements of approximately 500 line kilometers.

In February 2019, Kosmos and BP signed Carry Advance Agreements with the national oil companies of Mauritania and Senegal, which obligate us separately to finance the respective national oil company’s share of certain development costs. Kosmos’ total share for the two agreements combined is up to $239.7 million, which is to be repaid through the national oil companies’ share of future revenues.

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 debt'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,
	2020	2021	2022	2023	2024	Thereafter	2019
	(In thousands, except percentages)						
Fixed rate debt:							
Senior Notes	$ —	$ —	$ —	$ —	$ —	$ 650,000	$ (664,957)
Fixed interest rate	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	
Variable rate debt:							
Facility(1)	$ —	$ 174,800	$ 284,200	$ 271,600	$ 440,829	$ 228,571	$ (1,400,000)
Weighted average interest rate(2)	4.94%	4.75%	5.19%	5.33%	5.88%	6.28%	

(1) The amounts included in the table represent principal maturities only. The scheduled maturities of debt are based on the level of borrowings and the available borrowing base as of December 31, 2019. 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) Based on outstanding borrowings as noted in (1) above and the LIBOR yield curves plus applicable margin at the reporting date. Excludes commitment fees related to the Facility and Corporate Revolver.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2019, our material off-balance sheet arrangements and transactions include short-term operating leases and undrawn letters of credit. There are no other transactions, arrangements, or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect Kosmos' liquidity or availability of or requirements for capital resources.

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. 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 sold 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, 2019 and 2018, we had no oil and gas imbalances recorded in our consolidated financial statements.

Our oil and gas revenues are recognized when production has been sold to a purchaser at a fixed or determinable price, title has transferred and collectability is probable. Certain revenues are based on provisional price contracts which contain an embedded derivative that is required to be separated from the host contract for accounting purposes. The host contract is the receivable from oil sales at the spot price on the date of sale. The embedded 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 charged to expense 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. 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 crude oil and natural gas to the surface are expensed.

Receivables. Our receivables consist of joint interest billings, oil sales and other receivables. For our Ghana oil sales receivable, we require a letter of credit to be posted to secure the outstanding receivable. Receivables from joint interest owners are stated at amounts due, net of any allowances for doubtful accounts. We determine our allowance 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.

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, 2019 and 2018, 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.

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 have also previously 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 a liabilities measured at fair value. We do not apply hedge accounting to our oil derivative contracts.

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

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

Asset Retirement Obligations. We account for asset retirement obligations as required by the 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 shall be recognized at the asset's acquisition date as if that obligation were incurred on that 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 contracts and regulations 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. An impairment loss shall be measured as the amount by which the carrying amount of a long-lived asset exceeds its fair value. 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 less cost to sell.

We believe the assumptions used in our undiscounted cash flow analysis to test for impairment are appropriate and result in a reasonable estimate of future cash flows. The undiscounted cash flows from the analysis exceeded the carrying amount of our long-lived assets. The most significant assumptions are the pricing and production estimates used in undiscounted cash flow analysis. Where unproved reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the evaluation. In order to evaluate the sensitivity of the assumptions, we assumed a hypothetical reduction in our production profile and lower pricing during the early years which still showed no impairment. If we experience further declines in oil pricing, increases in our estimated future expenditures or a decrease in our estimated production profile our long-lived assets could be at risk for impairment.

Consolidations / Equity Method of Accounting. The Consolidated Financial Statements include the accounts of our wholly-owned subsidiaries. They also include Kosmos' share of the undivided interest in certain assets, liabilities, revenues and expenses. Investments in corporate joint ventures, which we exercise significant influence over, are accounted for using the equity method of accounting.

Equity method investments are integral to our operations. The other parties, who also have an equity interest in these companies, are independent third parties. Kosmos does not invest in these companies in order to remove liabilities from its balance sheet.

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, 2019:

	Derivative Contracts Assets (Liabilities)	
	Commodities	
	(In thousands)	
Fair value of contracts outstanding as of December 31, 2018	$	30,744
Changes in contract fair value		(70,724)
Contract maturities		31,458
Fair value of contracts outstanding as of December 31, 2019	$	(8,522)

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, Eugene Island, Heavy Louisiana Sweet and Mars crude.

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.

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, 2019:

				Weighted Average Price per Bbl					Asset (Liability) Fair Value at December 31,
Term	**Type of Contract**	**Index**	**MBbl**	**Net Deferred Premium Payable/(Receivable)**	**Swap**	**Sold Put**	**Floor**	**Ceiling**	**2019(2)**
2020									
January — December	Three-way collars	Dated Brent	6,000	$ 0.45	$ —	$ 45.00	$ 57.50	$ 80.18	$ 5,888
January — December	Swaps with sold puts	Dated Brent	2,000	—	60.53	48.75	—	—	(6,038)
January — December	Put spread	Dated Brent	6,000	0.75	—	50.00	59.17	—	6,678
January — December	Sold calls(1)	Dated Brent	8,000	1.17	—	—	—	85.00	(782)
2021									
January — December	Swaps with sold puts	Dated Brent	2,000	—	60.56	47.50	—	—	(1,311)
January — December	Sold calls(1)	Dated Brent	6,000	—	—	—	—	71.67	(9,669)

(1) Represents call option contracts sold to counterparties to enhance other derivative positions.

(2) Fair values are based on the average forward oil prices on December 31, 2019.

In February 2020, we entered into put option contracts for 3,700.0 MMBbl from February 2020 through December 2020 to move the previous three-way collar sold puts at a weighted average price of $42.50 per barrel to $50.00 per barrel. We used part of the proceeds from the trades to enter into swap and sold put contracts for 2,000.0 MMBbl from January 2021 through December 2021 with a fixed price of $60.00 per barrel and a sold put price of $50.00 per barrel. The contracts are indexed to Dated Brent prices.

At December 31, 2019, our open commodity derivative instruments were in a net liability position of $5.2 million. As of December 31, 2019, a hypothetical 10% price increase in the commodity futures price curves would decrease future pre-tax earnings by approximately $54.6 million. Similarly, a hypothetical 10% price decrease would increase future pre-tax earnings by approximately $49.2 million.

Interest Rate Sensitivity

At December 31, 2019, we had indebtedness outstanding under the Facility of $1.4 billion, which bore interest at a floating rate. The interest rate on this indebtedness as of December 31, 2019 was approximately 5.3%. If LIBOR increased 10% at this level of floating rate debt, we would pay an additional $2.9 million in interest expense per year. We pay commitment fees on the $200.0 million of undrawn availability under the Facility and on the $400.0 million of undrawn availability under the Corporate Revolver at December 31, 2019, which are not subject to changes in interest rates.

Item 8. Financial Statements and Supplementary Data

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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, 2019 and 2018, the related consolidated statements of operations, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2019, 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 as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, in conformity with US 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, 2019, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 24, 2020 expressed an unqualified opinion thereon.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company‘s management. Our responsibility is to express an opinion on the Company‘s consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the US 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 consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

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

	Depletion of Proved Oil and Natural Gas Properties
Description of the Matter	At December 31, 2019, the net book value of the Company's proved oil and natural gas properties was $2.811 billion, and depletion expense was $542.9 million for the year then ended. As described in Note 2, the Company follows the successful efforts method of accounting for its oil and natural gas properties. Proved properties and support equipment and facilities are depleted using the unit of production method based on estimated proved oil and natural gas reserves. Capitalized exploratory drilling costs that result in a discovery of proved reserves and development costs are depleted using the unit of production method based on estimated proved developed oil and natural gas reserves for the related field. The Company's oil and natural gas reserves are estimated by independent reserve engineers. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. Significant judgment is required by the Company's independent reserve engineers in evaluating geological and engineering data when estimating proved oil and natural gas reserves. Estimating reserves also requires the selection of inputs, including oil and natural gas price assumptions and future operating and capital cost assumptions, among others. Because of the complexity involved in estimating oil and natural gas reserves, management used independent reserve engineers to prepare the estimate of reserve quantities as of December 31, 2019. Auditing the Company's depletion calculation is complex because of the use of the work of independent reserve engineers and the evaluation of management's determination of the inputs described above used by the independent reserve engineers in estimating proved oil and natural gas reserves.
How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design and tested the operating effectiveness of the controls over the Company's process to calculate depletion, including management's controls over the completeness and accuracy of the financial data and inputs provided to the independent reserve engineers for use in estimating the proved oil and natural gas reserves. Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the independent reserve engineers used to prepare the estimate of proved oil and natural gas reserves. Additionally, in assessing whether we can use the work of the independent reserve engineers we evaluated the completeness and accuracy of the financial data and inputs described above used by the independent reserve engineers in estimating proved oil and natural gas reserves by agreeing them to source documentation and we identified and evaluated corroborative and contrary evidence. For proved undeveloped reserves, we evaluated management's development plan for compliance with the Securities and Exchange Commission rule that undrilled locations are scheduled to be drilled within five years, unless specific circumstances justify a longer time, by assessing consistency of the development projections with the Company's drill plan and the availability of capital relative to the drill plan. We also tested the mathematical accuracy of the depletion calculations, including comparing the estimated proved oil and natural gas reserve amounts used to the Company's reserve report.
	Asset Retirement Obligations
Description of the Matter	At December 31, 2019, the Company's asset retirement obligations totaled $235.1 million. As described in Note 2, the fair value of a liability for an asset retirement obligation is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. If a tangible long-lived asset with an existing asset retirement obligation is acquired, a liability for that obligation is recognized at the asset's acquisition or in-service date. Auditing the Company's asset retirement obligations was complex and highly judgmental due to the significant estimation required by management to determine the estimated present value of the amount of dismantlement, removal, site reclamation and similar activities associated with the Company's oil and natural gas properties. In particular, the estimate was sensitive to significant assumptions such as the expected cash outflows for retirement obligations and the ultimate productive life of the properties.
How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design and tested the operating effectiveness of the controls over the Company's process to estimate asset retirement obligations, including controls over management's review of the significant assumptions described above. Our audit procedures included, among others, testing the significant assumptions discussed above and the underlying data used by the Company. For example, we evaluated expected cash outflows for asset retirement obligations by comparing to recent offshore activities and costs. We also compared the ultimate productive life of the properties to forecasts of production based on estimates of proved oil and natural gas reserves, as estimated by independent reserve engineers. We involved our specialists to assist in our evaluation of the expected cash flows for retirement obligations.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2004.

Dallas, Texas
February 24, 2020

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, 2019, 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, 2019, 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, 2019 and 2018, the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2019, and the related notes and financial statement schedules listed in the Index at Item 15(a) and our report dated February 24, 2020 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 appearing in Item 9A. 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 US federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ Ernst & Young LLP

Dallas, Texas
February 24, 2020

KOSMOS ENERGY LTD.

CONSOLIDATED BALANCE SHEETS

(In thousands, except share data)

	December 31, 2019	December 31, 2018
Assets		
Current assets:		
Cash and cash equivalents	$ 224,502	$ 173,515
Restricted cash	4,302	4,527
Receivables:		
Joint interest billings, net	81,424	64,572
Oil sales	64,142	48,164
Related party	—	5,580
Other	28,727	21,690
Inventories	114,412	84,827
Prepaid expenses and other	36,192	68,040
Derivatives	12,856	38,785
Total current assets	566,557	509,700
Property and equipment:		
Oil and gas properties, net	3,624,751	3,444,864
Other property, net	17,581	14,837
Property and equipment, net	3,642,332	3,459,701
Other assets:		
Equity method investment	—	51,896
Restricted cash	542	7,574
Long-term receivables	43,430	19,002
Deferred financing costs, net of accumulated amortization of $14,681 and $12,065 at December 31, 2019 and December 31, 2018, respectively	6,321	8,937
Deferred tax assets	32,779	14,004
Derivatives	2,302	14,312
Other	22,969	3,063
Total assets	$ 4,317,232	$ 4,088,189
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable	$ 149,483	$ 176,540
Accrued liabilities	380,704	195,596
Derivatives	8,914	12,172
Total current liabilities	539,101	384,308
Long-term liabilities:		
Long-term debt, net	2,008,063	2,120,547
Derivatives	11,478	10,181
Asset retirement obligations	230,526	145,336
Deferred tax liabilities	653,221	477,179
Other long-term liabilities	33,141	9,160
Total long-term liabilities	2,936,429	2,762,403
Stockholders' equity:		
Preference shares, $0.01 par value; 200,000,000 authorized shares; zero issued at December 31, 2019 and December 31, 2018	—	—
Common stock, $0.01 par value; 2,000,000,000 authorized shares; 445,779,367 and 442,914,675 issued at December 31, 2019 and December 31, 2018, respectively	4,458	4,429
Additional paid-in capital	2,297,221	2,341,249
Accumulated deficit	(1,222,970)	(1,167,193)
Treasury stock, at cost, 44,263,269 shares at December 31, 2019 and 2018, respectively	(237,007)	(237,007)
Total stockholders' equity	841,702	941,478
Total liabilities and stockholders' equity	$ 4,317,232	$ 4,088,189

See accompanying notes.

KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)

	Years Ended December 31, 2019	2018	2017
Revenues and other income:			
Oil and gas revenue	$ 1,499,416	$ 886,666	$ 578,139
Gain on sale of assets	10,528	7,666	—
Other income, net	(35)	8,037	58,697
Total revenues and other income	1,509,909	902,369	636,836
Costs and expenses:			
Oil and gas production	402,613	224,727	126,850
Facilities insurance modifications, net	(24,254)	6,955	(820)
Exploration expenses	180,955	301,492	216,050
General and administrative	110,010	99,856	68,302
Depletion, depreciation and amortization	563,861	329,835	255,203
Interest and other financing costs, net	155,074	101,176	77,595
Derivatives, net	71,885	(31,430)	59,968
(Gain) loss on equity method investments, net	—	(72,881)	6,252
Other expenses, net	24,648	(6,501)	5,291
Total costs and expenses	1,484,792	953,229	814,691
Income (loss) before income taxes	25,117	(50,860)	(177,855)
Income tax expense	80,894	43,131	44,937
Net loss	$ (55,777)	$ (93,991)	$ (222,792)
Net loss per share:			
Basic	$ (0.14)	$ (0.23)	$ (0.57)
Diluted	$ (0.14)	$ (0.23)	$ (0.57)
Weighted average number of shares used to compute net loss per share:			
Basic	401,368	404,585	388,375
Diluted	401,368	404,585	388,375
Dividends declared per common share	$ 0.1808	$ —	$ —

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, 2016	395,859	$ 3,959	$ 1,975,247	$ (850,410)	$ (47,597)	$ 1,081,199
Equity-based compensation	—	—	40,899	—	—	40,899
Restricted stock awards and units	2,740	27	(27)	—	—	—
Purchase of treasury stock / tax withholdings	—	—	(1,594)	—	(600)	(2,194)
Net loss	—	—	—	(222,792)	—	(222,792)
Balance as of December 31, 2017	398,599	3,986	2,014,525	(1,073,202)	(48,197)	897,112
Acquisition of oil and gas properties	34,994	350	307,594	—	—	307,944
Equity-based compensation	—	—	36,464	—	—	36,464
Restricted stock awards and units	9,322	93	(93)	—	—	—
Purchase of treasury stock / tax withholdings	—	—	(17,241)	—	(188,810)	(206,051)
Net loss	—	—	—	(93,991)	—	(93,991)
Balance as of December 31, 2018	442,915	4,429	2,341,249	(1,167,193)	(237,007)	941,478
Dividends ($0.1808 per share)	—	—	(74,813)	—	—	(74,813)
Equity-based compensation	—	—	32,797	—	—	32,797
Restricted stock awards and units	2,864	29	(29)	—	—	—
Purchase of treasury stock / tax withholdings	—	—	(1,983)	—	—	(1,983)
Net loss	—	—	—	(55,777)	—	(55,777)
Balance as of December 31, 2019	445,779	$ 4,458	$ 2,297,221	$ (1,222,970)	$ (237,007)	$ 841,702

See accompanying notes.

KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31, 2019	2018	2017
Operating activities			
Net loss	$ (55,777)	$ (93,991)	$ (222,792)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depletion, depreciation and amortization (including deferred financing costs)	573,118	339,214	265,407
Deferred income taxes	(90,370)	9,145	9,505
Unsuccessful well costs and leasehold impairments	87,813	123,199	43,201
Change in fair value of derivatives	67,436	(29,960)	71,822
Cash settlements on derivatives, net (including $(36.3) million and $(137.1) million and $38.7 million on commodity hedges during 2019, 2018, and 2017)	(31,458)	(137,942)	25,888
Equity-based compensation	32,370	35,230	39,913
Gain on sale of assets	(10,528)	(7,666)	—
Loss on extinguishment of debt	24,794	4,324	—
Distributions in excess of equity in earnings / (Undistributed equity in earnings)	—	(45)	6,252
Other	9,069	2,865	5,952
Changes in assets and liabilities:			
(Increase) decrease in receivables	(29,735)	175,954	29,365
(Increase) decrease in inventories	(28,970)	8,848	1,653
(Increase) decrease in prepaid expenses and other	34,586	(18,731)	(31,710)
Increase (decrease) in accounts payable	(83,921)	7,440	(94,434)
Increase (decrease) in accrued liabilities	129,723	(157,393)	86,595
Net cash provided by operating activities	628,150	260,491	236,617
Investing activities			
Oil and gas assets	(340,217)	(213,806)	(140,495)
Other property	(11,796)	(7,935)	(2,858)
Acquisition of oil and gas properties, net of cash acquired	—	(961,764)	—
Equity method investment	—	—	(231,280)
Return of investment from KTIPI	—	184,664	—
Proceeds on sale of assets	15,000	13,703	222,068
Notes receivable from partners	(26,918)	—	—
Net cash used in investing activities	(363,931)	(985,138)	(152,565)
Financing activities			
Borrowings under long-term debt	175,000	1,175,000	200,000
Payments on long-term debt	(425,000)	(325,000)	(250,000)
Net proceeds from issuance of senior notes	641,875	—	—
Redemption of senior secured notes	(535,338)	—	—
Purchase of treasury stock / tax withholdings	(1,983)	(206,051)	(2,194)
Dividends	(72,599)	—	—
Deferred financing costs	(2,444)	(38,672)	(67)
Net cash provided by (used in) financing activities	(220,489)	605,277	(52,261)
Net increase (decrease) in cash, cash equivalents and restricted cash	43,730	(119,370)	31,791
Cash, cash equivalents and restricted cash at beginning of period	185,616	304,986	273,195
Cash, cash equivalents and restricted cash at end of period	$ 229,346	$ 185,616	$ 304,986
Supplemental cash flow information			
Cash paid for:			
Interest, net of capitalized interest	$ 99,928	$ 83,831	$ 55,381
Income taxes	$ 43,909	$ 45,984	$ 48,815
Non-cash activity:			
Contribution to equity method investment	$ —	$ —	$ 133,893
Dissolution of equity method investment	$ —	$ —	$ (122,407)
Common stock issued for acquisition of oil and gas properties	$ —	$ 307,944	$ —

See accompanying notes.

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements

1. Organization

Kosmos Energy Ltd. changed its jurisdiction of incorporation from Bermuda to the State of Delaware (the "Redomestication") in December 2018. All outstanding common shares of Kosmos Energy Ltd., an exempted company incorporated pursuant to the laws of Bermuda, were automatically converted by operation of law, on a one-for-one basis, into shares of common stock of Kosmos Energy Ltd., a company incorporated pursuant to the laws of Delaware. The number of shares of the Company's common stock outstanding immediately after the Redomestication was the same as the number of common shares of Kosmos Energy Ltd. outstanding immediately prior to the Redomestication. Kosmos Energy Ltd. was originally incorporated pursuant to the laws of Bermuda in January 2011 to become a holding company for Kosmos Energy Holdings. As part of the Redomestication, we transferred all of our equity interests in Kosmos Energy Holdings to a new, wholly-owned subsidiary, Kosmos Energy Delaware Holdings, LLC, a Delaware limited liability company. As a holding company, Kosmos Energy Ltd.'s management operations are conducted through a wholly-owned subsidiary, Kosmos Energy, LLC. The terms "Kosmos," the "Company," "we," "us," "our," "ours," and similar terms refer to Kosmos Energy Ltd. and its wholly-owned subsidiaries, unless the context indicates otherwise.

Kosmos is a full-cycle deepwater independent oil and gas exploration and production company focused along the Atlantic Margins. Our key assets include production offshore Ghana, Equatorial Guinea and U.S. Gulf of Mexico, as well as a world-class gas development offshore Mauritania and Senegal. We also maintain a sustainable exploration program balanced between proven basin infrastructure-led exploration (Equatorial Guinea and U.S. Gulf of Mexico), emerging basins (Mauritania, Senegal and Suriname) and frontier basins (Cote d'Ivoire, Namibia, Sao Tome and Principe, and South Africa). 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 and production of oil and natural gas. We have operations in four geographic areas: Ghana, Equatorial Guinea, Mauritania/Senegal and the United States 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. Investments in corporate joint ventures, which we exercise significant influence over, are accounted for using the equity method of accounting. All intercompany transactions have been eliminated.

Investments in companies that are partially owned by the Company are integral to the Company's operations. The other parties, who also have an equity interest in these companies, are independent third parties that share in the business results according to their ownership. Kosmos does not invest in these companies in order to remove liabilities from its balance sheet.

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. 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 material impact on our reported net income (loss), current assets, total assets, current liabilities, total liabilities, shareholders' equity or cash flows, except as disclosed related to the adoption of recent accounting pronouncements.

Cash, Cash Equivalents and Restricted Cash

	December 31,		
	2019	2018	2017
	(In thousands)		
Cash and cash equivalents	$ 224,502	$ 173,515	$ 233,412
Restricted cash - current	4,302	4,527	56,380
Restricted cash - long-term	542	7,574	15,194
Total cash, cash equivalents and restricted cash shown in the consolidated statements of cash flows	$ 229,346	$ 185,616	$ 304,986

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.

In accordance with certain of our petroleum contracts, we have posted letters of credit related to performance guarantees for our minimum work obligations. Certain of these letters of credit are cash collateralized in accounts held by us and as such are classified as restricted cash. Upon completion of the minimum work obligations and/or entering into the next phase of the petroleum contract, the requirement to post the existing letters of credit will be satisfied and the cash collateral will be released. However, additional letters of credit may be required should we choose to move into the next phase of certain of our petroleum contracts. As of December 31, 2019 and 2018, we had $4.3 million and $4.5 million, respectively, of current restricted cash and $0.3 million and $7.4 million, respectively, of long-term restricted cash used to cash collateralize performance guarantees related to our petroleum contracts. As of December 31, 2019 and 2018, we also had $0.2 million in other long-term restricted cash.

Receivables

Our receivables consist of joint interest billings, oil and gas sales, related party and other receivables. For our oil sales receivable in Ghana, we require a letter of credit to be posted to secure the outstanding receivable. Receivables from joint interest owners are stated at amounts due, net of any allowances for doubtful accounts. We determine our allowance 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 $2.7 million and $1.2 million in current joint interest billings receivables as of December 31, 2019 and 2018, respectively.

Inventories

Inventories consisted of $112.3 million and $83.4 million (including $22.1 million acquired through the DGE acquisition) of materials and supplies and $2.1 million and $1.4 million of hydrocarbons as of December 31, 2019 and 2018, 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 $4.6 million, $0.3 million and $0.9 million during the years ended December 31, 2019, 2018 and 2017 for materials and supplies inventories as other expenses, net in the consolidated statements of operations and other in the consolidated statements of cash flows.

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

Leases (Policy applicable beginning January 1, 2019)

In February 2016, the FASB issued ASU 2016-02, “Leases (Topic 842).” ASU 2016-02 was issued to increase transparency and comparability across organizations by recognizing substantially all leases on the balance sheet through the concept of right-of-use lease assets and liabilities. Under prior accounting guidance, lessees did not recognize lease assets or liabilities for leases classified as operating leases. The ASU was effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years with early adoption permitted. In July 2018, the FASB issued ASU 2018-11, which added a transition option permitting entities to apply the provisions of the new standard at its adoption date instead of the earliest comparative period presented in the consolidated financial statements. Under this transition option, comparative reporting would not be required, and the provisions of the standard would be applied prospectively to leases in effect at the date of adoption. The Company adopted the guidance prospectively during the first quarter of 2019. As part of our adoption, we elected not to reassess historical lease classification, recognize short-term leases on our balance sheet, nor separate lease and non-lease components for our real estate leases. The adoption and implementation of this ASU resulted in a $21.7 million increase in assets and liabilities related to our leasing activities, which primarily consists of office leases. Our adoption of ASU 2016-02 did not impact retained earnings or other components of equity as of December 31, 2018.

We account for leases in accordance with ASC Topic 842, Leases, (“ASC 842”). We determine if an arrangement is a lease at contract inception. A lease exists when a contract conveys to the customer the right to control the use of identified property, plant, or equipment for a period of time in exchange for consideration. The definition of a lease embodies two conditions: (1) there is an identified asset in the contract that is land or a depreciable asset (i.e., property, plant, and equipment), and (2) the customer has the right to control the use of the identified asset.

In the normal course of business, the Company enters into various lease agreements for real estate and equipment related to its exploration, development and production activities that are currently accounted for as operating leases. Operating leases are included in Other assets, Accrued liabilities, and Other long-term liabilities on our consolidated balance sheets. The lease liabilities are initially and subsequently measured at the present value of the unpaid lease payments at the lease commencement date.

Key estimates and judgments include how we determined: (1) the discount rate we use to discount the unpaid lease payments to present value; (2) lease term; and (3) lease payments.

1. ASC 842 requires a lessee to discount its unpaid lease payments using the interest rate implicit in the lease or, if that rate cannot be readily determined, its incremental borrowing rate. As most of our leases where we are the lessee do not provide an implicit rate, we use our incremental borrowing rate based on the information available at commencement date in determining the present value of lease payments. Our incremental borrowing rate for a lease is the rate of interest we would have to pay on a collateralized basis to borrow an amount equal to the lease payments under similar terms.

2. The lease term for all of our leases includes the non-cancellable period of the lease plus any additional periods covered by either an option to extend (or not to terminate) the lease that we are reasonably certain to exercise, or an option to extend (or not to terminate) the lease controlled by the lessor.

3. Lease payments included in the measurement of the lease asset or liability comprise the following: fixed payments (including in-substance fixed payments), variable payments that depend on index or rate, and the exercise price of a lessee option to purchase the underlying asset if we are reasonably certain to exercise. Amounts expected to be payable under residual value guarantee are also lease payments included in the measurement of the lease liability.

The Right-of-use ("ROU") asset is initially measured at cost, which comprises the initial amount of the lease liability adjusted for lease payments made at or before the lease commencement date, plus any initial direct costs incurred less any lease incentives received.

For operating leases, the ROU asset is subsequently measured throughout the lease term at the carrying amount of the lease liability, plus initial direct costs, plus (minus) any prepaid (accrued) lease payments, less the unamortized balance of lease incentives received. Lease expense for lease payments is recognized on a straight-line basis over the lease term.

We monitor for events or changes in circumstances that require a reassessment of a lease. When a reassessment results in the re-measurement of a lease liability, a corresponding adjustment is made to the carrying amount of the corresponding ROU asset unless doing so would reduce the carrying amount of the ROU asset to an amount less than zero. In that case, the amount of the adjustment that would result in a negative ROU asset balance is recorded in profit or loss.

We have lease agreements which include lease and non-lease components. We have elected to combine lease and non-lease components for all lease contracts.

We have elected not to recognize ROU assets and lease liabilities for all short-term leases that have a lease term of 12 months or less. We recognize the lease payments associated with our short-term leases as an expense on a straight-line basis over the lease term.

We adopted ASU 2016-02 using a modified retrospective transition approach as of the effective date as permitted by the amendments in ASU 2018-11, which provides an alternative modified retrospective transition method. As a result, we were not required to adjust our comparative period financial information for effects of the standard or make the new required lease disclosures for periods before the date of adoption (i.e. January 1, 2019). We have elected to adopt the package of transition practical expedients and, therefore, have not reassessed (1) whether existing or expired contracts contain a lease, (2) lease classification for existing or expired leases or (3) the accounting for initial direct costs that were previously capitalized. We did not elect the practical expedient to use hindsight for leases existing at the adoption date.

Exploration and Development Costs

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

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

Depletion, Depreciation and Amortization

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

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

	Years Depreciated
Leasehold improvements	1 to 8
Office furniture, fixtures and computer equipment	3 to 7
Vehicles	5

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.

Impairment of Long-lived Assets

The Company reviews its 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. An impairment loss shall be measured as the amount by which the carrying amount of a long-lived asset exceeds its fair value. Assets to be disposed of and assets not expected to provide any future service potential to the Company are recorded at the lower of carrying amount or fair value less cost to sell.

We believe the assumptions used in our undiscounted cash flow analysis to test for impairment indicators are appropriate and result in a reasonable estimate of future cash flows. The undiscounted cash flows from the analysis exceeded the carrying amount of our long-lived assets. The most significant assumptions are the pricing and production estimates used in undiscounted cash flow analysis. Where unproved reserves exist, an appropriately risk-adjusted amount of these reserves may be included in the evaluation. In order to evaluate the sensitivity of the assumptions, we assumed a hypothetical reduction in our production profile which still showed no impairment. If we experience declines in oil pricing, increases in our estimated future expenditures or a decrease in our estimated production profile our long-lived assets could be at risk for impairment.

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 Natural Gas Reserves

Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion and assessment of impairment of our oil and natural gas properties. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. As additional proved reserves are discovered, reserve quantities and future cash flows will be estimated by independent petroleum consultants and prepared in accordance with guidelines established by the Securities and Exchange Commission (“SEC”) and the Financial Accounting Standards Board (“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 sold 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, 2019 and 2018, 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 provisional price contracts which contain an embedded derivative that is required to be separated from the host contract for accounting purposes. The host contract is the receivable from oil sales at the spot price on the date of sale. The embedded 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.

Oil and gas revenue is composed of the following:

	Years Ended December 31,		
	2019	2018	2017
Revenues from contract with customer - Equatorial Guinea	$ 297,831	$ —	$ —
Revenues from contract with customer - Ghana	740,464	741,033	590,642
Revenues from contract with customers - U.S. Gulf of Mexico	459,960	147,596	—
Provisional oil sales contracts	1,161	(1,963)	(12,503)
Oil and gas revenue	$ 1,499,416	$ 886,666	$ 578,139

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 awards and restricted stock units and (ii) a Monte Carlo simulation to determine the fair value of restricted stock awards and restricted stock units with a combination of market and service vesting criteria. Forfeitures are recognized in the period in which they occur.

Restructuring Charges

The Company accounts for restructuring charges and related termination benefits in accordance with ASC 712-Compensation-Nonretirement Postemployment Benefits. Under these standards, the costs associated with termination benefits are recorded during the period in which the liability is incurred. During the year ended December 31, 2019, we recognized $11.5 million in restructuring charges for employee severance and related benefit costs incurred as part of a corporate reorganization in Other expenses, net in the consolidated statement of operations.

Treasury Stock

We record treasury stock purchases at cost. Our treasury stock purchases are from our employees that surrendered shares to the Company to satisfy their statutory tax withholding requirements and are not part of a formal stock repurchase plan. In November 2018, Kosmos repurchased 35 million shares of our common stock from funds affiliated with Warburg Pincus LLC in a privately negotiated transaction at a price per share of $5.38. The total aggregate purchase price for the share repurchase was approximately $188 million. The remainder of our treasury stock is forfeited restricted stock awards granted under our long-term incentive plan.

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. However, based on the current demand for crude oil and the fact that alternative purchasers are readily available, we believe that the loss of our marketing agent 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 international operations. For our U.S. Gulf of Mexico operations, crude oil and natural gas are transported to customers using third-party pipelines. For the years ended December 31, 2019 and 2018, revenue from Phillips 66 Company made up approximately 20% and 11%, respectively, of our total consolidated revenue and was included in our U.S. Gulf of Mexico segment.

Recent Accounting Standards

Recently Adopted

In February 2016, the FASB issued ASU 2016-02, “Leases (Topic 842).” ASU 2016-02 was issued to increase transparency and comparability across organizations by recognizing substantially all leases on the balance sheet through the concept of right-of-use lease assets and liabilities. Under current accounting guidance, lessees do not recognize lease assets or liabilities for leases classified as operating leases. The ASU is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years with early adoption permitted. In July 2018, the FASB issued ASU 2018-11, which added a transition option permitting entities to apply the provisions of the new standard at its adoption date instead of the earliest comparative period presented in the consolidated financial statements. Under this transition option, comparative reporting would not be required, and the provisions of the standard would be applied prospectively to leases in effect at the date of adoption. The Company adopted the guidance prospectively during the first quarter of 2019. As part of our adoption, we elected not to reassess historical lease classification, recognize short-term leases on our balance sheet, nor separate lease and non-lease components for our real estate leases. The adoption and implementation of this ASU resulted in a $21.7 million increase in assets and liabilities related to our leasing activities which primarily consists of office leases. Our adoption of ASU 2016-02 did not impact retained earnings or other components of equity as of December 31, 2018.

Not Yet Adopted

In June 2016, ASU 2016-13, "Measurement of Credit Losses on Financial Instruments," was issued requiring measurement of all expected credit losses for certain types of financial instruments, including trade receivables, held at the reporting date based on historical experience, current conditions and reasonable and supportable forecasts. This standard is effective January 1, 2020, and we do not expect it to have a significant impact on our consolidated financial statements.

In December 2019, the FASB issued ASU 2019-12, “Simplifying the Accounting for Income Taxes”. The amendments in the ASU are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2020. Early adoption is permitted. The Company is evaluating the impact of this standard.

3. Acquisitions and Divestitures

2019 Transactions

During the first quarter of 2019, we entered into a petroleum contract covering offshore Marine XXI block with the Republic of the Congo, subject to governmental approvals. Upon approval, we will hold an 85% participating interest and be the operator. The Congolese national oil company, SNPC, has a 15% carried interest during the exploration period. Should a commercial discovery be made, SNPC's 15% carried interest will convert to a participating interest of at least 15%. The petroleum contract covers approximately 2,350 square kilometers, with a first exploration period of four years and includes a work program to acquire and interpret 2,200 square kilometers of 3D seismic. There are two optional exploration phases, each for a period of three years, which are subject to additional work program commitments.

In March 2019, we completed an agreement with a subsidiary of Ophir Energy plc ("Ophir") to acquire the remaining interest in Block EG-24, offshore Equatorial Guinea, which increased our participating interest to 80% and named Kosmos as operator. The Equatorial Guinean national oil company, GEPetrol, has a 20% carried interest during the exploration period. Should a commercial discovery be made, GEPetrol's 20% carried interest will convert to a 20% participating interest.

In September 2019, we completed a farm-in agreement with OK Energy to acquire a 45% non-operated interest in the Northern Cape Ultra Deep block offshore the Republic of South Africa. The petroleum contract covers approximately 6,930 square kilometers at water depths ranging from 2,500 to 3,100 meters and has an initial exploration phase of two years.

In November 2019, we completed a farm-out agreement with Shell Sao Tome and Principe B.V. to farm-out a 20% participating interest in Block 6 and a 30% participating interest in Block 11, offshore Sao Tome and Principe, resulting in our participating interests in Blocks 6 and 11 being 25% and 35%, respectively. During the year ended December 31, 2019, we recognized a $10.5 million gain related to the farm-out of Blocks 6 and 11 offshore Sao Tome and Principe.

2018 Transactions

In March 2018, as part of our alliance with BP, we entered into petroleum contracts covering Blocks 10 and 13 with the Democratic Republic of Sao Tome and Principe. We presently have a 35% participating interest in the blocks and the operator, BP, holds a 50% participating interest. The national petroleum agency, Agencia Nacional Do Petroleo De Sao Tome E Principe ("ANP-STP") has a 15% carried interest in the blocks through exploration. The petroleum contracts cover approximately 13,600 square kilometers, with a first exploration period of four years from the effective date (March 2018). The exploration periods can be extended an additional four years at our election subject to fulfilling specific work obligations. The first exploration period work programs include a 13,500 square kilometer 3D seismic acquisition requirement across the two blocks.

In June 2018, we completed a farm-in agreement with a subsidiary of Ophir for Block EG-24, offshore Equatorial Guinea, whereby we acquired our initial non-operated participating interest of 40%. As part of the agreement, we reimbursed a portion of Ophir's previously incurred exploration costs and agreed to carry Ophir's share of the costs. The petroleum contract covers approximately 3,500 square kilometers, with a first exploration period of three years from the effective date (March 2018) which can be extended up to four additional years at our election subject to fulfilling specific work obligations. The first exploration period work program includes a 3,000 square kilometer 3D seismic acquisition requirement which was completed in November 2018. The Equatorial Guinean national oil company, GEPetrol, has a 20% carried interest during the exploration period. Should a commercial discovery be made, GEPetrol's 20% carried interest will convert to a 20% participating interest.

In September 2018, we completed the acquisition of DGE, a deepwater company operating in the U.S. Gulf of Mexico, from First Reserve Corporation and other shareholders for a total consideration of $1.275 billion, comprised of $952.6 million in cash, $307.9 million in Kosmos common stock and $14.9 million of transaction related costs. We funded the cash portion of the purchase price using cash on hand and drawings under our existing credit facilities. We also received $200.0 million of additional firm commitments under the Facility, which provided further liquidity to the Company. The DGE acquisition was accounted for under the asset acquisition method and the purchase price allocation is shown below. The purchase price allocation was based on the estimated relative fair value of identifiable assets acquired and liabilities assumed.

The estimated fair value measurements of oil and gas assets acquired and asset retirement obligations liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair value of oil and gas properties and asset retirement obligations were measured using the discounted cash flow technique of valuation. Significant inputs to the valuation of oil and gas properties include estimates of: (i) reserves, (ii) future operating and development costs, (iii) future commodity prices, (iv) future plugging and abandonment costs, (v) estimated future cash flows, and (vi) a market-based weighted average cost of capital rate.

		Purchase Price Allocation (in thousands)
Fair value of assets acquired:		
Proved oil and gas properties	$	1,037,511
Unproved oil and gas properties		298,159
Accounts receivable and other		180,989
Total assets acquired	$	1,516,659
Fair value of liabilities assumed:		
Accrued liabilities and other	$	126,530
Asset retirement obligations		74,482
Derivative liabilities		40,265
Total liabilities assumed	$	241,277
Purchase price:		
Cash consideration paid	$	952,586
Fair value of common stock(1)		307,944
Transaction related costs		14,852
Total purchase price	$	1,275,382

(1) Based on 34,993,585 shares of common stock issued at a price of $8.80 per share, which was the opening Kosmos common stock price on September 14, 2018, the closing date of the acquisition.

As a result of the DGE acquisition, we included $147.6 million of revenues and $30.5 million of direct operating expenses in our consolidated statements of operations for the period from September 14, 2018 to December 31, 2018.

In October 2018, Kosmos entered into a strategic exploration alliance with Shell Exploration Company B.V. (“Shell”) to jointly explore in Southern West Africa. Initially the alliance will focus on Namibia where Kosmos has completed a farm-in to Shell's acreage in PEL 39, and Sao Tome and Principe where we have entered into exclusive negotiations for Shell to take an interest in Kosmos’ acreage in Blocks 5, 6, 11, and 12. As part of the alliance, our two companies intend to jointly evaluate opportunities in adjacent geographies. This alliance is consistent with Kosmos’ strategy of partnering with supermajors to leverage complementary skill sets. Shell has deep expertise in carbonate plays, while Kosmos brings significant knowledge of the Cretaceous in West Africa. Furthermore, by working with Shell, Kosmos has a partner with the expertise to efficiently move exploration successes through the development stage.

2017 Transactions

In December 2016, we announced transactions with affiliates of BP in Mauritania and Senegal following a competitive farm-out process for our interests in our blocks offshore Mauritania and Senegal. The Mauritania and Senegal transactions closed in January 2017 and February 2017, respectively. In Mauritania, BP acquired a 62% participating interest in our four Mauritania licenses (C6, C8, C12 and C13). In Senegal, BP acquired a 49.99% interest in KBSL, our majority owned affiliate company which held a 60% participating interest in the Cayar Offshore Profond and Saint Louis Offshore Profond blocks (the "Senegal Blocks") offshore Senegal. Previously we indicated that KBSL would hold a 65% participating interest upon the completion of our exercise in December 2016 of an option to increase our equity in each contract area by 5% in exchange for carrying Timis Corporation Limited’s (“Timis”) paying interest share of a third well in either contract area, subject to a maximum gross well cost of $120.0 million. However, we agreed to withdraw the exercise of this call option upon completion of an agreement between BP and Timis by which BP acquired Timis’ entire 30% participating interest in the Senegal Blocks. The transaction between BP and Timis was completed and KBSL’s participating interest in these blocks remained at 60%. In consideration for these transactions, Kosmos received $162 million in cash up front during the first quarter of 2017 and will receive $228 million exploration and appraisal carry (increased from $221 million upon completion of the transfer of a 30% working interest to BP Senegal Investments Limited), up to $533 million in a development carry and variable consideration up to $2 per barrel for up to 1 billion barrels of liquids, structured as a production royalty, subject to future liquids discovery and prevailing oil prices. The effective date of these transactions was July 1, 2016, with BP paying interim costs from the effective date to the closing dates. We reduced our unproved property balance by $221.9 million for the consideration received as a result of these transactions including the upfront cash and interim costs from the transaction date to the effective date. See Note 7—Equity Method Investments for further discussion of our investment in KBSL.

In November 2015, we entered into a line of credit agreement with Timis, whereby Timis had the right to draw up to $30.0 million on the line of credit to offset its joint interest billings arising from costs under the Senegal Blocks petroleum agreements. The line of credit agreement was terminated in April 2017 when Timis entered into an agreement with BP to acquire Timis' 30% participating interest in the Senegal Blocks. As a result of the termination of this credit agreement, Kosmos received $16 million in August 2017 representing payment in full of outstanding amounts drawn on the line of credit.

In September 2017, we closed a farm-in agreement with Tullow Mauritania Limited, a subsidiary of Tullow Oil plc (“Tullow”), to acquire a 15% non-operated participating interest in Block C18 offshore Mauritania. Based on the terms of the agreement, we reimbursed Tullow a portion of past and interim period costs and will partially carry future costs.

In the fourth quarter of 2017, through a joint venture with an affiliate of Trident Energy ("Trident"), we acquired all of the equity interest of Hess International Petroleum Inc., a subsidiary of Hess Corporation ("Hess"), which holds an 85% paying interest (80.75% revenue interest) in the Ceiba Field and Okume Complex assets. Under the terms of the agreement, Kosmos and Trident each own 50% of Hess International Petroleum Inc. Hess International Petroleum Inc. was subsequently renamed Kosmos-Trident International Petroleum Inc. ("KTIPI"). Kosmos is primarily responsible for exploration and subsurface evaluation while Trident is primarily responsible for production operations and optimization. The gross acquisition price was $650 million effective as of January 1, 2017. After post closing entries Kosmos paid net cash of approximately $231 million, with a combination of cash on hand and availability under the Facility. The transaction was accounted for as an equity method investment. See Note 7—Equity Method Investments for further discussion of our investment in KTIPI.

In October 2017, we entered into petroleum contracts covering Blocks EG-21, S, and W with the Republic of Equatorial Guinea. We had an 80% participating interest and were the operator in all three blocks. In August 2018, we closed a farm-out agreement with Trident, whereby they acquired a 40% participating interest in blocks EG-21, S, and W, resulting in a $7.7 million gain. After giving effect to the farm-out agreement, we hold a 40% participating interest and remain the operator in all three blocks. The Equatorial Guinean national oil company, Guinea Equatorial De Petroleos ("GEPetrol"), has a 20% carried participating interest during the exploration period. Should a commercial discovery be made, GEPetrol's 20% carried interest will convert to a 20% participating interest. The petroleum contracts cover approximately 6,000 square kilometers, with a first exploration period of five years from the effective date (March 2018). The first exploration period consists of two sub-periods of three and two years, respectively. The first exploration sub-period work program includes a 6,000 square kilometer 3D seismic acquisition requirement across the three blocks.

In December 2017, as part of our Alliance with BP, we entered into petroleum contracts covering Blocks CI-526, CI-602, CI-603, CI-707 and CI-708 with the Government of Cote d'Ivoire. We have a 45% participating interest and are the operator in all five blocks. BP has a 45% participating interest in the blocks and the Cote d'Ivoire national oil company, PETROCI Holding ("PETROCI"), currently has a 10% carried interest. The petroleum contracts cover approximately 17,000 square kilometers, with a first exploration period of three years. The first exploration period work program includes a 12,000 square kilometer 3D seismic acquisition across the five blocks.

4. Joint Interest Billings, Related Party Receivables and Notes Receivables

Joint Interest Billings

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 on the face of the consolidated balance sheets as current and long-term receivables based on when collection is expected to occur.

In Ghana, the contractor group funded GNPC’s 5% share of the Tweneboa, Enyenra and Ntomme (“TEN”) development costs. The block partners are being reimbursed for such costs plus interest out of a portion of GNPC’s TEN production revenues. As of December 31, 2019 and 2018, the current portion of the joint interest billing receivables due from GNPC for the TEN fields development costs were $14.0 million and $14.0 million, respectively, and the long-term portion were $16.0 million and $14.0 million.

Related Party Receivables

The Company's related party receivables consists primarily of receivables from Trident who, until January 2019, we shared a 50% interest in KTIPI. As of December 31, 2019 and 2018 the balance due from Trident consists of zero and $5.6 million related to joint interest billings for the exploration blocks and Kosmos' support of KTIPI operations. Subsequent to the unwind of KTIPI, Trident is no longer considered a related party.

Notes Receivables

In February 2019, Kosmos and BP signed Carry Advance Agreements with the national oil companies of Mauritania and Senegal which obligate us separately to finance the respective national oil company's share of certain development costs incurred through first gas production for Greater Tortue Ahmeyim Phase 1, currently projected in 2022. Kosmos' share for the two agreements combined is up to $239.7 million, which is to be repaid with interest through the national oil companies' share of future revenues. As of December 31, 2019, the balance due from the national oil companies was $27.4 million, which is classified as Long-term receivables in our consolidated balance sheets.

5. Property and Equipment

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

	December 31,	
	2019	2018
	(In thousands)	
Oil and gas properties:		
Proved properties	$ 4,904,648	$ 4,236,489
Unproved properties	814,065	759,472
Total oil and gas properties	5,718,713	4,995,961
Accumulated depletion	(2,093,962)	(1,551,097)
Oil and gas properties, net	3,624,751	3,444,864
Other property	61,598	51,987
Accumulated depreciation	(44,017)	(37,150)
Other property, net	17,581	14,837
Property and equipment, net	$ 3,642,332	$ 3,459,701

We recorded depletion expense of $542.9 million, $316.3 million and $244.9 million and depreciation expense of $6.9 million, $4.6 million and $3.4 million for the years ended December 31, 2019, 2018 and 2017, respectively. The increase to oil and gas properties from 2018 to 2019 primarily relates to proportionate consolidation resulting from the unwind of our equity method investment in KTIPI. See Note 7 — Equity Method Investments for additional information.

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 completed wells as of and during the years ended December 31, 2019, 2018 and 2017. The table excludes $3.0 million, $65.6 million and $43.2 million in costs that were capitalized and subsequently expensed during the same year for the years ended December 31, 2019, 2018 and 2017, respectively. During 2017, the exploratory well costs associated with the Mahogany and Teak fields were reclassified to proved property as they were unitized into the Jubilee Unit as part of the Greater Jubilee Full Field Development Plan.

	Years Ended December 31,		
	2019	2018	2017
	(In thousands)		
Beginning balance	$ 367,665	$ 410,113	$ 734,463
Additions to capitalized exploratory well costs pending the determination of proved reserves	78,125	10,518	69,567
Additions associated with the acquisition of DGE	—	26,224	—
Reclassification due to determination of proved reserves(1)	—	(26,224)	(176,881)
Divestitures(2)	—	—	(206,400)
Contribution of oil and gas property to equity method investment - KBSL	—	—	(131,764)
Dissolution of equity method investment - KBSL	—	—	121,128
Capitalized exploratory well costs charged to expense(3)	—	(52,966)	—
Ending balance	$ 445,790	$ 367,665	$ 410,113

(1) Represents the reclassification of Nearly Headless Nick well costs associated with the DGE acquisition in 2018 and inclusion of the Mahogany and Teak discoveries in the Jubilee Unit in 2017.

(2) Represents the reduction in basis of suspended well costs associated with the Mauritania and Senegal transactions with BP

(3) Primarily related to Akasa and Wawa wells as we wrote off $38.1 million and $13.6 million, respectively, of previously capitalized costs exploratory well costs to exploration expense during the third quarter of 2018. These impairments are included in our Ghana segment.

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,		
	2019	2018	2017
	(In thousands, except well counts)		
Exploratory well costs capitalized for a period of one year or less	$ 29,121	$ —	$ 67,159
Exploratory well costs capitalized for a period of one to two years	78,245	299,253	291,252
Exploratory well costs capitalized for a period of three years or longer	338,424	68,412	51,702
Ending balance	$ 445,790	$ 367,665	$ 410,113
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	3	3	5

As of December 31, 2019, the projects with exploratory well costs capitalized for more than one year since the completion of drilling are related to the Greater Tortue Ahmeyim Unit, which crosses the Mauritania and Senegal maritime border, BirAllah discovery (formerly known as the Marsouin discovery) in Block C8 offshore Mauritania, and the Yakaar and Teranga discoveries in the Cayar Offshore Profond block offshore Senegal.

Greater Tortue Ahmeyim Unit — In May 2015, we completed the Tortue-1 exploration well in Block C8 offshore Mauritania, which encountered hydrocarbon pay. Three additional wells have been drilled in the unit development area of the Greater Tortue Ahmeyim field, Ahmeyim-2 in Mauritania and Guembeul-1 and Greater Tortue Ahmeyim-1 in Senegal. We completed a drill stem test on the Tortue-1 well in August 2017, which confirmed the production capabilities of the Greater Tortue Ahmeyim unit. In December 2018, we made a final investment decision to develop Phase 1 of the Greater Tortue Ahmeyim unit, with first gas production currently estimated in 2022. Additionally, in February 2020 the Tortue Phase 1 SPA was executed.

BirAllah Discovery — In November 2015, we completed the Marsouin-1 exploration well in the northern part of Block C8 offshore Mauritania, which encountered hydrocarbon pay. Following additional evaluation, a decision regarding commerciality is expected be made. During the fourth quarter of 2019, we completed the nearby Orca-1 exploration well which encountered hydrocarbon pay. Following additional evaluation, a decision regarding commerciality is expected to be made. The Bir Allah and Orca discoveries are being analyzed as a joint development.

Yakaar and Teranga Discoveries — In May 2016, we completed the Teranga-1 exploration well in the Cayar Offshore Profond Block offshore Senegal, which encountered hydrocarbon pay. In June 2017, we completed the Yakaar-1 exploration well in the Cayar Offshore Profond Block offshore Senegal, which encountered hydrocarbon pay. In November 2017, an integrated Yakaar-Teranga appraisal plan was submitted to the government of Senegal. In September 2019, we completed the Yakaar-2 appraisal well which encountered hydrocarbon pay. The Yakaar-2 well was drilled approximately nine kilometers from the Yakaar-1 exploration well. Following additional evaluation, a decision regarding commerciality is expected to be made. The Yakaar and Teranga discoveries are being analyzed as a joint development.

7. Equity Method Investments

Kosmos BP Senegal Limited

As part of our transaction in Senegal with BP in February 2017, our participating interests in the Cayar Offshore Profond and Saint Louis Offshore Profond Blocks ("Senegal Blocks") were contributed to KBSL, a corporate joint venture in which we owned a 50.01% interest which was accounted for under the equity method of accounting.

In October 2017, KBSL transferred a 30% participating interest in the Senegal Blocks to BP Senegal Investments Limited in exchange for its outstanding shares of KBSL. As a result, KBSL became a wholly-owned subsidiary of Kosmos, and no longer is accounted for under the equity method of accounting. After the transfer, KBSL has a 30% working interest in the Senegal Blocks.

Our initial contribution to KBSL was $133.9 million, which was recorded at our carrying costs. Our share of losses in KBSL during the period it was accounted for as an equity method investment is reflected in our consolidated statements of operations as (Gain) loss on equity method investments, net. During the year ended December 31, 2017, we recognized $11.5 million related to our share of losses in KBSL.

Equatorial Guinea

As part of our acquisition of KTIPI in 2017, a corporate joint venture entity in which we owned a 50% interest until January 2019, we acquired an indirect participating interest in Block G offshore Equatorial Guinea. The objective of this transaction was to acquire the Ceiba Field and Okume Complex with the intent to optimize production and increase reserves. Below is a summary of financial information for KTIPI presented on a 100% basis for 2018. The financial information for 2019 is presented as part of our consolidated financial statements based on our direct 40.375% ownership in the Ceiba Field and Okume Complex.

	December 31, 2018
	(In thousands)
Assets	
Total current assets	$ 149,950
Property and equipment, net	271,627
Other assets	21
Total assets	$ 421,598
Liabilities and shareholders' deficit	
Total current liabilities	$ 226,311
Total long term liabilities	536,178
Shareholders' deficit:	
Total shareholders' deficit	(340,891)
Total liabilities and shareholders' deficit	$ 421,598

	Year Ended December 31, 2018	Period November 28, 2017 through December 31, 2017
	(In thousands)	
Revenues and other income:		
Oil and gas revenue	$ 721,299	$ 54,615
Other income	(477)	294
Total revenues and other income	720,822	54,909
Costs and expenses:		
Oil and gas production	147,685	15,509
Depletion and depreciation	126,983	10,738
Other expenses, net	429	(19)
Total costs and expenses	275,097	26,228
Income before income taxes	445,725	28,681
Income tax expense	156,981	6,588
Net income	$ 288,744	$ 22,093
Kosmos' share of net income	$ 144,372	$ 11,046
Basis difference amortization(1)	71,491	5,812
Equity in earnings - KTIPI	$ 72,881	$ 5,234

(1) The basis difference, which is associated with oil and gas properties and subject to amortization, has been allocated to the Ceiba Field and Okume Complex. We amortize the basis difference using the unit-of-production method.

When evaluating our equity method investments for impairment, we review our ability to recover the carrying amount of such investments or the entity's ability to sustain earnings that justify its carrying amount. As of December 31, 2018, we determined that we had the ability to recover the carrying amount of our equity method investment in KTIPI. As such, no impairment has been recorded. Our initial investment has been increased for our net share of equity in earnings as adjusted for our basis differential and reduced by cash dividends received. During the year ended December 31, 2018, we received $257.5 million of cash dividends from KTIPI.

Effective as of January 1, 2019, our outstanding shares in KTIPI were transferred to Trident in exchange for a 40.375% undivided interest in the Ceiba Field and Okume Complex. As a result, our interest in the Ceiba Field and Okume Complex is accounted for under the proportionate consolidation method of accounting going forward. This transaction was accounted for as an asset acquisition. The carrying value of the equity method investment was allocated to the undivided interest acquired and net working capital based on the estimated relative fair value of the acquired assets.

The estimated fair value measurements of oil and gas assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair value of oil and gas properties and asset retirement obligations were measured using the discounted cash flow technique of valuation. Significant inputs to the valuation of oil and gas properties include estimates of: (i) reserves, (ii) future operating and development costs, (iii) future commodity prices, (iv) future plugging and abandonment costs, (v) estimated future cash flows, and (vi) a market-based weighted average cost of capital rate.

	Carrying Value Allocation (in thousands)	
Assets acquired:		
Proved oil and gas properties	$	372,144
Unproved oil and gas properties		103,909
Prepaids and other		7,273
Total assets acquired	$	483,326
Liabilities assumed:		
Asset retirement obligations	$	114,395
Deferred tax liabilities		247,636
Accrued liabilities and other		69,399
Total liabilities assumed	$	431,430
Carrying value:		
Equity method investment carrying value at December 31, 2018	$	51,896

8. Debt

	December 31,			
	2019		2018	
	(In thousands)			
Outstanding debt principal balances:				
Facility	$	1,400,000	$	1,325,000
Corporate Revolver		—		325,000
Senior Notes		650,000		—
Senior Secured Notes		—		525,000
Total		2,050,000		2,175,000
Unamortized deferred financing costs and discounts(1)		(41,937)		(54,453)
Long-term debt, net	$	2,008,063	$	2,120,547

(1) Includes $32.8 million and $40.5 million of unamortized deferred financing costs related to the Facility and $9.1 million and $14.0 million of unamortized deferred financing costs and discounts related to the Senior Notes as of December 31, 2019 and December 31, 2018, respectively.

Facility

In February 2018, the Company amended and restated the Facility with a total commitment of $1.5 billion from a number of financial institutions with additional commitments up to $0.5 billion being available if the existing financial institutions increase their commitments or if commitments from new financial institutions are added. In November 2018, the Company exercised its option with existing financial institutions to provide the Company with an additional commitment of $100 million in the aggregate under the Facility. The borrowing base calculation includes value related to the Jubilee, TEN, Ceiba and Okume fields. The Facility supports our oil and gas exploration, appraisal and development programs and corporate activities. As part of the debt refinancing in February 2018, the repayment of borrowings under the existing facility attributable to financial institutions that did not participate in the amended Facility was accounted for as an extinguishment of debt, and $4.1 million of existing unamortized debt issuance costs and deferred interest attributable to those participants was expensed in interest and other financing costs, net in the first quarter of 2018. As of December 31, 2019, we have $32.8 million of unamortized issuance costs related to the Facility, which will be amortized over the remaining term of the Facility. In December 2018, the Company entered into letter agreements with existing financial institutions, which provided the Company with an additional commitment of $100 million in the aggregate under the Facility effective January 31, 2019. This took the total commitments to $1.7 billion as of January 31, 2019. In March 2019, following the lender's annual redetermination, the available borrowing base under our Facility was limited to the Facility size of $1.7 billion. The commitments were reduced by $100.0 million to $1.6 billion following the Senior Notes issuance in April 2019.

As of December 31, 2019, borrowings under the Facility totaled $1.4 billion and the undrawn availability under the Facility was $200.0 million, which includes the additional commitments as referenced above. Interest is the aggregate of the applicable margin (3.25% to 4.50%, depending on the length of time that has passed from the date the Facility was entered into) and LIBOR. 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. As part of the amendment and restatement process in February 2018, commitment fees were lowered from 40% 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 March 31, 2022, outstanding borrowings will be constrained by an amortization schedule. The Facility has a final maturity date of March 31, 2025. As of December 31, 2019, we had no letters of credit issued under the Facility.

Kosmos has the right to cancel all the undrawn commitments under the amended and restated Facility. The amount of funds available to be borrowed under the Facility, also known as the borrowing base amount, is determined each year on March 31, as amended. The borrowing base amount is based on the sum of the net present value 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 Ghana and Equatorial Guinea.

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 contains customary cross default provisions.

We were in compliance with the financial covenants contained in the Facility as of the September 30, 2019 (the most recent assessment date).

Corporate Revolver

In August 2018, we amended and restated the Corporate Revolver maintaining the borrowing capacity at $400.0 million, extending the maturity date from November 2018 to May 2022 and lowering the margin 100 basis points to 5%. This results in lower commitment fees on the undrawn portion of the total commitments, which is 30% per annum of the respective margin. The Corporate Revolver is available for general corporate purposes and for oil and gas exploration, appraisal and development programs. As of December 31, 2019, we have $6.3 million of net deferred financing costs related to the Corporate Revolver, which will be amortized over the remaining term. These deferred financing costs are included in the Other assets section of our consolidated balance sheets.

As of December 31, 2019, there were no borrowings outstanding under the Corporate Revolver and the undrawn availability under the Corporate Revolver was $400.0 million.

Interest is the aggregate of the applicable margin (5.0%); LIBOR; and mandatory cost (if any, as defined in the Corporate Revolver). Interest is payable on the last day of each interest period (and, if the interest period is longer than six months, on the dates falling at six-month intervals after the first day of the interest period). We pay commitment fees on the undrawn portion of the total commitments. Commitment fees for the lenders are equal to 30% per annum of the respective margin when a commitment is available for utilization.

The Corporate Revolver expires on May 31, 2022. The available amount is not subject to borrowing base constraints. Kosmos has the right to cancel all the undrawn commitments under the Corporate Revolver. The Company is required to repay certain amounts due under the Corporate Revolver with sales of certain subsidiaries or sales of certain assets. If an event of default exists under the Corporate Revolver, the lenders can accelerate the maturity and exercise other rights and remedies, including the enforcement of security granted pursuant to the Corporate Revolver over certain assets held by us.

We were in compliance with the financial covenants contained in the Corporate Revolver as of September 30, 2019 (the most recent assessment date). The Corporate Revolver contains customary cross default provisions.

Revolving Letter of Credit Facility

In July 2013, we entered into a revolving letter of credit facility agreement (“LC Facility”). The size of the LC Facility was $75.0 million, as amended in July 2015, with additional commitments up to $50.0 million being available if the existing lender increases its commitment or if commitments from new financial institutions are added.

In July 2016, we amended and restated the LC Facility, extending the maturity date to July 2019. Other amendments included increasing the margin from 0.5% to 0.8% per annum on amounts outstanding, adding a commitment fee payable quarterly in arrears at an annual rate equal to 0.65% on the available commitment amount and providing for issuance fees to be payable to the lender per new issuance of a letter of credit. We may voluntarily cancel any commitments available under the LC Facility at any time. During the first quarter of 2017, the LC Facility size was increased to $115.0 million and in April 2017, we reduced the size of our LC Facility to $70 million. In February 2018, the LC Facility was increased to $73 million to facilitate the issuance of additional letters of credit. In July 2018 and December 2018, the LC Facility size was voluntarily reduced to $40.0 million and $20.0 million, respectively, based on the expiration of several large outstanding letters of credit. The LC Facility expired in July 2019, however, as of December 31, 2019, there were five outstanding letters of credit totaling $3.1 million under the LC Facility, which will remain outstanding until the respective letters of credit expire. The LC Facility contains customary cross default provisions.

In 2019, we issued two letters of credit totaling $20.4 million under a new letter of credit arrangement, which does not currently require cash collateral.

7.875% Senior Secured Notes due 2021

During August 2014, the Company issued $300.0 million of Senior Secured Notes and received net proceeds of approximately $292.5 million after deducting discounts, commissions and deferred financing costs. The Company used the net proceeds to repay a portion of the outstanding indebtedness under the Facility and for general corporate purposes.

During April 2015, we issued an additional $225.0 million of Senior Secured Notes and received net proceeds of $206.8 million after deducting discounts, commissions and other expenses. We used the net proceeds to repay a portion of the outstanding indebtedness under the Facility and for general corporate purposes. The additional $225.0 million of Senior Secured Notes have identical terms to the initial $300.0 million Senior Secured Notes, other than the date of issue, the initial price, the first interest payment date and the first date from which interest accrued.

In April 2019, all of the Senior Secured Notes were redeemed for $543.8 million, including accrued interest and the early redemption premium. The redemption resulted in a $22.9 million loss on extinguishment of debt, which is included in Interest and other financing costs, net on the consolidated statement of operations.

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 Senior Secured Notes, 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 Senior Notes.

The Senior Notes mature on April 4, 2026. We will pay interest in arrears on the Senior Notes each April 4 and October 4, commencing on October 4, 2019. The Senior Notes are senior, unsecured obligations of Kosmos Energy Ltd. and rank equal in right of payment with all of its existing and future senior indebtedness (including all borrowings under the Corporate Revolver) 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 guaranteed on a senior, unsecured basis by certain subsidiaries owning the Company's Gulf of Mexico assets, and on a subordinated, unsecured basis by certain subsidiaries that guarantee the Facility.

At any time prior to April 4, 2022, and subject to certain conditions, the Company may, on one or more occasions, redeem up to 40% of the original principal amount of the Senior Notes with an amount not to exceed the net cash proceeds of certain equity offerings at a redemption price of 107.1% of the outstanding principal amount of the 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 April 4, 2022 the Company may, on any one or more occasions, redeem all or a part of the Senior Notes at a redemption price equal to 100%, plus any accrued and unpaid interest, and plus a "make-whole" premium. On or after April 4, 2022, the Company may redeem all or a part of the Senior Notes at the redemption prices (expressed as percentages of principal amount) set forth below plus accrued and unpaid interest:

Year	Percentage
On or after April 4, 2022, but before April 4, 2023	103.6%
On or after April 4, 2023, but before April 4, 2024	101.8%
On or after April 4, 2024 and thereafter	100.0%

We may also redeem the 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 Senior Notes at a price equal to the principal amount of the 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 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 Senior Notes indenture, the Company will be required to make an offer to repurchase the 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 Senior Notes indenture, we will be required to use the net proceeds to make an offer to purchase the Senior Notes at an offer price in cash in an amount equal to 100% of the principal amount of the Senior Notes, plus accrued and unpaid interest to, but excluding, the repurchase date.

The Senior Notes indenture restricts our ability and the ability of our 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 our subsidiaries to make dividends or other payments to us, 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 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.

At December 31, 2019, the estimated repayments of debt during the five years and thereafter are as follows:

	Payments Due by Year						
	Total	2020	2021	2022	2023	2024	Thereafter
	(In thousands)						
Principal debt repayments(1)	$ 2,050,000	$ —	$ 174,800	$ 284,200	$ 271,600	$ 440,829	$ 878,571

(1) Includes the scheduled maturities for the $650.0 million aggregate principal amount of Senior Notes issued in April 2019 and borrowings under the Facility. The scheduled maturities of debt related to the Facility are based on, as of December 31, 2019, our level of borrowings and our estimated future available borrowing base commitment levels in future periods. Any increases or decreases in the level of borrowings or increases or decreases in the available borrowing base would impact the scheduled maturities of debt during the next five years and thereafter.

Interest and other financing costs, net

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

	Years Ended December 31,		
	2019	2018	2017
	(In thousands)		
Interest expense	$ 145,507	$ 114,134	$ 92,687
Amortization—deferred financing costs	9,257	9,379	10,204
Loss on extinguishment of debt	24,794	4,324	—
Capitalized interest	(28,077)	(28,331)	(30,282)
Deferred interest	1,919	(1,138)	2,577
Interest income	(3,692)	(3,455)	(3,422)
Other, net	5,366	6,263	5,831
Interest and other financing costs, net	$ 155,074	$ 101,176	$ 77,595

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, 2019. Volumes and weighted average prices are net of any offsetting derivative contracts entered into.

				Weighted Average Price per Bbl				
Term	Type of Contract	Index	MBbl	Net Deferred Premium Payable/(Receivable)	Swap	Sold Put	Floor	Ceiling
2020:								
January — December	Three-way collars	Dated Brent	6,000	$ 0.45	$ —	$ 45.00	$ 57.50	$ 80.18
January — December	Swaps with sold puts	Dated Brent	2,000	—	60.53	48.75	—	—
January — December	Put spread	Dated Brent	6,000	0.75	—	50.00	59.17	—
January — December	Sold calls(1)	Dated Brent	8,000	1.17	—	—	—	85.00
2021:								
January — December	Swaps with sold puts	Dated Brent	2,000	—	60.56	47.50	—	—
January — December	Sold calls(1)	Dated Brent	6,000	—	—	—	—	71.67

(1) Represents call option contracts sold to counterparties to enhance other derivative positions.

In February 2020, we entered into put option contracts for 3.7 MMBbl from February 2020 through December 2020 to move the previous three-way collar sold puts at a weighted average price of $42.50 per barrel to $50.00 per barrel. We used part of the proceeds from the trades to enter into swap and sold put contracts for 2.0 MMBbl from January 2021 through December 2021 with a fixed price of $60.00 per barrel and a sold put price of $50.00 per barrel. The contracts are indexed to Dated Brent prices.

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

The following tables disclose the Company's derivative instruments as of December 31, 2019 and 2018 and gain/(loss) from derivatives during the years ended December 31, 2019, 2018 and 2017.

Type of Contract	Balance Sheet Location	Estimated Fair Value Asset (Liability) December 31, 2019	Estimated Fair Value Asset (Liability) December 31, 2018
		(In thousands)	
Derivatives not designated as hedging instruments:			
Derivative assets:			
Commodity(1)	Derivatives assets—current	$ 12,856	$ 38,350
Provisional oil sales	Receivables: Oil sales	(3,287)	435
Commodity(2)	Derivatives assets—long-term	2,302	14,312
Derivative liabilities:			
Commodity(3)	Derivatives liabilities—current	(8,914)	(12,172)
Commodity(4)	Derivatives liabilities—long-term	(11,478)	(10,181)
Total derivatives not designated as hedging instruments		$ (8,521)	$ 30,744

(1) Includes net deferred premiums payable of $1.0 million and $1.6 million related to commodity derivative contracts as of December 31, 2019 and 2018, respectively.

(2) Includes net deferred premiums payable of $0.3 million and $1.3 million related to commodity derivative contracts as of December 31, 2019 and 2018, respectively.

(3) Includes net deferred premiums payable of $5.5 million and $18.0 million related to commodity derivative contracts as of December 31, 2019 and 2018, respectively.

(4) Includes net deferred premiums payable of $0.3 million and $0.5 million related to commodity derivative contracts as of December 31, 2019 and 2018, respectively.

Type of Contract	Location of Gain/(Loss)	Amount of Gain/(Loss) Years Ended December 31, 2019	2018	2017
		(In thousands)		
Derivatives not designated as hedging instruments:				
Commodity(1)	Oil and gas revenue	$ 1,161	$ (1,963)	$ (12,502)
Commodity	Derivatives, net	(71,885)	31,430	(59,968)
Interest rate	Interest expense	—	493	648
Total derivatives not designated as hedging instruments		$ (70,724)	$ 29,960	$ (71,822)

(1) Amounts represent the change in fair value of our provisional oil sales contracts.

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, 2019 and 2018, 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 and Disclosures, 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, 2019 and 2018, 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, 2019				
Assets:				
Commodity derivatives	$ —	$ 15,158	$ —	$ 15,158
Provisional oil sales	—	(3,287)	—	(3,287)
Liabilities:				
Commodity derivatives	—	(20,392)	—	(20,392)
Total	$ —	$ (8,521)	$ —	$ (8,521)
December 31, 2018				
Assets:				
Commodity derivatives	$ —	$ 52,662	$ —	$ 52,662
Provisional oil sales	—	435	—	435
Liabilities:				
Commodity derivatives	—	(22,353)	—	(22,353)
Total	$ —	$ 30,744	$ —	$ 30,744

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

Provisional Oil Sales

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

Debt

The following table presents the carrying values and fair values at December 31, 2019 and 2018:

	December 31, 2019		December 31, 2018	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In thousands)			
Senior Notes	$ 642,550	$ 664,957	$ —	$ —
Senior Secured Notes	—	—	511,873	525,026
Corporate Revolver	—	—	325,000	325,000
Facility	1,400,000	1,400,000	1,325,000	1,325,000
Total	$ 2,042,550	$ 2,064,957	$ 2,161,873	$ 2,175,026

The carrying value of our Senior Notes and Senior Secured Notes represents the principal amounts outstanding less unamortized discounts. The fair value of our Senior Notes is based on quoted market prices, which results in a Level 1 fair value measurement. The carrying value of the Facility approximates fair value since it is subject to short-term floating interest rates that approximate the rates available to us for those periods.

11. Asset Retirement Obligations

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

	December 31,	
	2019	2018
	(In thousands)	
Asset retirement obligations:		
Beginning asset retirement obligations	$ 151,953	$ 66,595
Additions associated with Equatorial Guinea - Ceiba Field and Okume Complex	114,395	—
Additions associated with the acquisition of DGE	—	74,482
Liabilities incurred during period	11,218	5,311
Liabilities settled during period	(7,156)	(3,345)
Revisions in estimated retirement obligations	(49,471)	—
Accretion expense	14,114	8,910
Ending asset retirement obligations	$ 235,053	$ 151,953

The asset retirement obligations reflect the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with our oil and gas properties. The Company utilizes current cost experience to estimate the expected cash outflows for retirement obligations. The Company estimates the ultimate productive life of the properties, a risk-adjusted discount rate, and an inflation factor in order to determine the current present value of this obligation. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation, a corresponding adjustment is made to the oil and gas property balance. The revisions in estimated retirement obligations during 2019 are related to changes in the estimated abandonment date in certain of our fields.

Effective as of January 1, 2019, our outstanding shares in KTIPI were transferred to Trident in exchange for a 40.375% undivided interest in the Ceiba Field and Okume Complex. As a result, our interest in the Ceiba Field and Okume Complex going forward is accounted for under the proportionate consolidation method of accounting, which includes additions to our asset retirement obligations.

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 January 2018 and January 2015, the board of directors approved amendments to the plan which added 11.0 million and 15.0 million shares, respectively, to the plan which were approved at the corresponding Annual General Meeting. The LTIP as amended provides for the issuance of 50.5 million shares pursuant to awards under the plan. As of December 31, 2019, the Company had approximately 10.6 million shares that remain available for issuance under the LTIP.

We record equity-based compensation expense equal to the fair value of share-based payments over the vesting periods of the LTIP awards. We recorded compensation expense from awards granted under our LTIP of $32.4 million, $35.2 million and $40.0 million during the years ended December 31, 2019, 2018 and 2017, respectively. The total tax benefit for the years ended December 31, 2019, 2018 and 2017 was $4.9 million, $6.6 million and $13.2 million, respectively. Additionally, we expensed a net tax shortfall (windfall) related to equity-based compensation of $1.2 million, $(0.4) million and $3.1 million for the years ended December 31, 2019, 2018 and 2017, respectively. The fair value of awards vested during 2019, 2018 and 2017 was approximately $20.3 million, $85.1 million, and $21.2 million, respectively. The Company granted both restricted stock awards and restricted stock units with service vesting criteria and granted both restricted stock awards and restricted stock units with a combination of market and service vesting criteria under the LTIP. Substantially, all of these awards vest over a three year period. Restricted stock awards are issued and included in the number of outstanding shares upon the date of grant and, if such awards are forfeited, they become treasury stock. Upon vesting, restricted stock units become issued and outstanding stock.

The following table reflects the outstanding restricted stock awards as of December 31, 2019:

	Service Vesting Restricted Stock Awards	Weighted- Average Grant-Date Fair Value	Market / Service Vesting Restricted Stock Awards	Weighted- Average Grant-Date Fair Value
	(In thousands)		(In thousands)	
Outstanding at December 31, 2016:	488	$ 8.83	—	$ —
Granted	—	—	—	—
Forfeited	—	—	—	—
Vested	(268)	8.97	—	—
Outstanding at December 31, 2017:	220	8.64	—	—
Granted	—	—	—	—
Forfeited	—	—	—	—
Vested	(220)	8.64	—	—
Outstanding at December 31, 2018:	—	—	—	—

There has been no additional restricted stock activity subsequent to December 31, 2018.

The following table reflects the outstanding restricted stock units as of December 31, 2019:

	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, 2016:	4,160	$ 6.91	7,194	$ 12.29
Granted	2,085	6.43	2,175	9.50
Forfeited	(137)	6.91	(21)	6.21
Vested	(1,925)	7.51	(896)	15.43
Outstanding at December 31, 2017:	4,183	6.39	8,452	11.26
Granted	2,402	7.07	8,111	12.38
Forfeited	(229)	6.40	(302)	8.95
Vested	(2,241)	6.95	(9,545)	13.75
Outstanding at December 31, 2018:	4,115	6.42	6,716	9.02
Granted	3,228	5.01	3,195	6.02
Forfeited	(591)	5.90	(813)	7.93
Vested	(2,021)	5.95	(1,300)	6.32
Outstanding at December 31, 2019:	4,731	5.71	7,798	8.42

As of December 31, 2019, total equity-based compensation to be recognized on unvested restricted stock units is $27.4 million over a weighted average period of 1.8 years.

For restricted stock units with a combination of market and service vesting criteria, the number of shares of common stock 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 up to 200% of the awards granted. The grant date fair value ranged from $4.83 to $15.71 per award. The Monte Carlo simulation model utilizes multiple input variables that determine 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 44.0% to 52.0%. 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 0.8% to 2.5% for restricted stock units. The expected quarterly dividends ranged from $0.045 to $0.050 commensurate with our current dividend experience.

In January 2020, we granted 2.7 million service vesting restricted stock units and 2.6 million market and service vesting restricted stock units to our employees under our long-term incentive plan. We expect to recognize approximately $40.8 million of non-cash compensation expense related to these grants over the next three years.

13. Income Taxes

Kosmos Energy Ltd. changed its jurisdiction of incorporation from Bermuda to the State of Delaware in December 2018. The company was not subject to taxation at the parent company level for the year ended December 31, 2017. 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.

On December 22, 2017, the President of the United States signed P.L. 115-97, the Tax Cut and Jobs Act (the Tax Reform Act), into law. Many of the provisions of the Tax Reform Act are effective beginning January 1, 2018, most notable of which is the reduction in the U.S. corporate income tax rate from 35% to 21%. Accounting Standards Codification Topic 740 requires deferred tax assets and liabilities be adjusted for the effect of changes in tax laws or tax rates during the period that includes the date of enactment. Accordingly, we have recorded a $16.7 million charge to deferred tax expense in December 2017 as a result of reducing our net deferred tax assets.

Effective January 1, 2019, our outstanding shares in KTIPI were transferred to Trident in exchange for a 40.375% undivided interest in the Ceiba Field and Okume Complex and Trident became the operator. As a result, our interest in the Ceiba Field and

Okume Complex will be accounted for under the proportionate consolidation method of accounting going forward. The following discussion reflects the proportionate consolidation of our Equatorial Guinean operations related to the Ceiba Field and Okume Complex for the year ended December 31, 2019. For years ended prior to 2019 KTIPI was accounted for as an Equity Method Investment.

The components of loss before income taxes were as follows:

	Years Ended December 31,		
	2019	2018	2017
	(In thousands)		
United States	$ (149,919)	$ 41,026	$ 6,068
Bermuda	—	(73,979)	(66,914)
Foreign—other	175,036	(17,907)	(117,009)
Income (loss) before income taxes	$ 25,117	$ (50,860)	$ (177,855)

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

	Years Ended December 31,		
	2019	2018	2017
	(In thousands)		
Current:			
United States	$ 185	$ 122	$ 10,976
Bermuda	—	—	—
Foreign—other	171,079	33,864	24,456
Total current	171,264	33,986	35,432
Deferred:			
United States	(18,776)	8,514	15,310
Bermuda	—	—	—
Foreign—other	(71,594)	631	(5,805)
Total deferred	(90,370)	9,145	9,505
Income tax expense	$ 80,894	$ 43,131	$ 44,937

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

	Years Ended December 31,		
	2019	2018	2017
	(In thousands)		
Tax at statutory rate(1)	$ 5,275	$ (10,681)	$ —
Foreign income (loss) taxed at different rates	32,690	5,013	9,381
Net non-taxable expense / insurance recoveries	(13,352)	3,256	(30)
West Leo arbitration settlement	—	(2,834)	1,736
Non-deductible insurance premiums	2,625	—	—
Non-deductible compensation	3,545	2,643	1,680
Deferred tax liability - undistributed earnings	—	(2,565)	2,565
Non-deductible and other items	3,998	656	3,790
Equity earnings - net of tax	—	(15,305)	—
Tax shortfall (windfall) on equity-based compensation, net	1,224	(387)	3,086
Change in valuation allowance	44,889	63,335	6,008
Change in U.S. tax rate	—	—	16,721
Total tax expense	$ 80,894	$ 43,131	$ 44,937
Effective tax rate(2)	322%	85%	25%

(1) On December 28, 2018, we changed our jurisdiction of incorporation from Bermuda to the State of Delaware. Kosmos Energy Ltd. discontinued as a Bermuda exempted company pursuant to Section 132G of the Companies Act 1981 of Bermuda and, pursuant to Section 265 of the General Corporation Law of the State of Delaware (the "DGCL"), continued its existence under the DGCL as a corporation organized in the State of Delaware. As a result, the statutory tax rate for the 2019 and 2018 reconciliation of income tax expense is the U.S. statutory tax rate of 21%. Our 2017 reconciliation of income tax expense is based on the Bermuda statutory tax rate of 0%.

(2) The effective tax rate during the years ended December 31, 2019, 2018 and 2017, were impacted by losses of $132.1 million, $261.2 million and $164.4 million, respectively, incurred in jurisdictions in which we are not subject to taxes and therefore do not generate any income tax benefits or where there are valuation allowances offsetting the corresponding deferred tax assets.

The effective tax rate for the United States is approximately 12%, 84% and 433% for the years ended December 31, 2019, 2018 and 2017, respectively. The effective tax rate in the United States is impacted by the effect the sum 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.

The effective tax rate for Ghana is approximately 29%, 36% and 49% for the years ended December 31, 2019, 2018 and 2017, respectively. The effective tax rate in Ghana is impacted by non-deductible expenditures, including amounts associated with damage to the turret bearing, which we expect to recover from insurance proceeds. Any such insurance recoveries would not be subject to income tax.

The effective tax rate for Equatorial Guinea is approximately 37% for the year ended December 31, 2019 and is impacted by non-deductible expenditures.

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

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

	December 31, 2019	December 31, 2018
	(In thousands)	
Deferred tax assets:		
Foreign capitalized operating expenses	$ 175,330	$ 128,809
Foreign net operating losses	19,576	28,050
United States net operating losses	58,903	59,336
United States deferred interest expense	15,426	—
Equity compensation	13,700	11,408
Unrealized derivative losses	1,471	—
Asset retirement obligation and other	43,159	29,450
Total deferred tax assets	327,565	257,053
Valuation allowance	(201,749)	(156,860)
Total deferred tax assets, net	125,816	100,193
Deferred tax liabilities:		
Depletion, depreciation and amortization related to property and equipment	(746,258)	(547,389)
Unrealized derivative gains	—	(15,979)
Total deferred tax liabilities	(746,258)	(563,368)
Net deferred tax liability	$ (620,442)	$ (463,175)

The Company has foreign net operating loss carryforwards of $68.8 million. Of these losses, we expect $0.6 million, $0.5 million, $15.6 million, $0.7 million, and $1.4 million to expire in 2020, 2021, 2022, 2023, and 2024, respectively, and $50.0 million do not expire. All of these losses currently have offsetting valuation allowances. The Company has $280.5 million of United States net operating loss that will not expire.

The Company is open to tax examinations in the United States for federal income tax return years 2016 through 2018 and in Ghana to federal income tax return years 2014 through 2018.

As of December 31, 2019, the Company had no material uncertain tax positions. The Company's policy is to recognize potential interest and penalties related to income tax matters in income tax expense.

14. Net Income (Loss) Per Share

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

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

	Years Ended December 31,		
	2019	2018	2017
	(In thousands, except per share data)		
Numerator:			
Net loss allocable to common stockholders	$ (55,777)	$ (93,991)	$ (222,792)
Denominator:			
Weighted average number of shares outstanding:			
Basic	401,368	404,585	388,375
Restricted stock awards and units(1)(2)	—	—	—
Diluted	401,368	404,585	388,375
Net loss per share:			
Basic	$ (0.14)	$ (0.23)	$ (0.57)
Diluted	$ (0.14)	$ (0.23)	$ (0.57)

(1) Our service vesting restricted stock awards represent participating securities because they participate in non-forfeitable dividends with common equity owners. Income allocable to participating securities represents the distributed and undistributed earnings attributable to the participating securities. Our restricted stock awards with market and service vesting criteria and all restricted stock units are not considered to be participating securities and, therefore, are excluded from the basic net income (loss) per share calculation. Our service vesting restricted stock awards do not participate in undistributed net losses because they are not contractually obligated to do so and, therefore, are excluded from the basic net income (loss) per share calculation in periods we are in a net loss position. All restricted stock awards were fully vested in January 2018.

(2) For the years ended December 31, 2019, 2018 and 2017, we excluded 15.3 million, 10.6 million and 12.9 million outstanding restricted stock awards and restricted stock units, respectively, from the computations of diluted net income per share because the effect would have been anti-dilutive. All restricted stock awards were fully vested in January 2018.

15. Commitments and Contingencies

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

The Jubilee Field in Ghana covers an area within both the WCTP and DT petroleum contract areas. It was agreed the Jubilee Field would be unitized for optimal resource recovery. Kosmos and its partners executed a comprehensive unitization and unit operating agreement, the Jubilee UUOA, to unitize the Jubilee Field and govern each party’s respective rights and duties in the Jubilee Unit, which was effective July 16, 2009. Pursuant to the terms of the Jubilee UUOA, the tract participations are subject to a process of redetermination. The initial redetermination process was completed on October 14, 2011. As a result of the initial redetermination process, our Unit Interest is 24.1%. These consolidated financial statements are based on these redetermined tract participations. Our unit interest may change in the future should another redetermination occur.

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. 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. These consolidated financial statements are based our current payment interest on development activities in the Greater Tortue Ahmeyim Unit of 26.7%. Our unit interest may change in the future should a redetermination occur.

We currently have a commitment to drill one exploration well in each of Sao Tome and Principe and Namibia and two exploration wells in Mauritania. In Sao Tome and Principe, we also have 3D seismic acquisition requirements of approximately 13,500 square kilometers. In South Africa, we have 2D seismic acquisition requirements of approximately 500 line kilometers.

Leases

We have commitments under operating leases primarily related to office leases. Our leases have initial lease terms ranging from 1 year to ten years. Certain lease agreements contain provisions for future rent increases.

The components of lease cost for the year ended December 31, 2019 is as follows:

	December 31, 2019
	(In thousands)
Operating lease cost	$ 5,480
Short-term lease cost	15,874
Total lease cost	$ 21,354

Other information related to operating leases at December 31, 2019, is as follows:

(In thousands, except lease term and discount rate)	December 31, 2019
Balance sheet classifications	
Other assets (right-of-use assets)	$ 20,008
Accrued liabilities (current maturities of leases)	1,139
Other long-term liabilities (non-current maturities of leases)	22,240
Weighted average remaining lease term	8.8 years
Weighted average discount rate	9.8%

The table below presents supplemental cash flow information related to leases during the year ended December 31, 2019:

	December 31, 2019
	(In thousands)
Operating cash flows for operating leases	$ 5,082
Investing cash flows for operating leases	$ 13,855

Future minimum rental commitments under our leases at December 31, 2019, are as follows:

	Operating Leases(1)
	(In thousands)
2020	$ 3,379
2021	4,201
2022	4,264
2023	4,327
2024	3,491
Thereafter	16,112
Total undiscounted lease payments	$ 35,774
Less: Imputed interest	(12,395)
Total lease liabilities	$ 23,379

(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.

Performance Obligations

As of December 31, 2019 and 2018, the Company had performance bonds totaling $222.0 million and $200.9 million, respectively, for our supplemental bonding requirements stipulated by the Bureau of Ocean Energy Management ("BOEM") and $3.7 million and $3.7 million, respectively, to another operator related to costs anticipated for the plugging and abandonment of certain wells and the removal of certain facilities in its U.S. Gulf of Mexico fields. As of December 31, 2019 and 2018, we had zero and $0.6 million, respectively of cash collateral against these secured performance bonds which is classified as Other long term assets in our consolidated balance sheets.

Dividends

On February 24, 2020, we announced our quarterly cash dividend of $0.0452 per common share. The dividend is payable on March 26, 2020 to stockholders of record on March 5, 2020.

16. Additional Financial Information

Accrued Liabilities

Accrued liabilities consisted of the following:

	December 31,	
	2019	2018
	(In thousands)	
Accrued liabilities:		
Exploration, development and production	$ 152,490	$ 92,613
Current asset retirement obligations	4,527	6,617
General and administrative expenses	44,575	39,373
Interest	33,584	18,152
Income taxes	103,566	8,958
Taxes other than income	3,375	4,613
Derivatives	4,837	441
Revenue payable	32,482	24,379
Other	1,268	450
	$ 380,704	$ 195,596

Gain on sale of assets

During the year ended December 31, 2019, we recognized a $10.5 million gain related to the farm-out of Blocks 6 and 11 offshore Sao Tome and Principe. During the year ended December 31, 2018, we recognized a $7.7 million gain related to the farm-out of Blocks EG-21, S, and W offshore Equatorial Guinea to Trident.

Other Income, net

Other income, net which includes Loss of Production Income ("LOPI") payments, consisted of zero, zero and $58.7 million for the years ended December 31, 2019, 2018 and 2017, respectively. Our LOPI coverage for the turret bearing issue on the Jubilee FPSO ended in May 2017.

Oil and Gas Production

Oil and gas production expense included insurance recoveries related to our increased cost of working covered by our LOPI policy of zero, zero, and $17.1 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Facilities Insurance Modifications, net

Facilities insurance modifications, net consists of costs associated with the long-term solution to convert the Jubilee FPSO to a permanently spread moored facility, net of any insurance reimbursements.

Other Expenses, net

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

	Years Ended December 31,		
	2019	**2018**	**2017**
	(In thousands)		
Loss on disposal of inventory	$ 4,590	$ 280	$ 866
Gain on insurance settlements	(3,509)	—	(461)
Loss on ARO liability settlements	193	—	—
Disputed charges and related costs, net of recoveries	4,149	(9,753)	4,962
Restructuring charges	11,528	—	—
Other, net	7,697	2,972	(76)
Other expenses, net	$ 24,648	$ (6,501)	$ 5,291

The disputed charges and related costs are expenditures arising from Tullow Ghana Limited's contract with Seadrill for use of the West Leo drilling rig once partner-approved 2016 work program objectives were concluded. Tullow charged such expenditures to the Deepwater Tano ("DT") joint account. Kosmos disputed through arbitration that these expenditures were chargeable to the DT joint account on the basis that the Seadrill West Leo drilling rig contract was not approved by the DT operating committee pursuant to the DT Joint Operating Agreement. In July 2018, the International Chamber of Commerce ("ICC") issued its Final Award in the arbitration in favor of Kosmos. As a result, we recovered from Tullow Ghana Limited disputed charges in the amount of $12.9 million in the form of cash payments and offsets against other unrelated joint venture costs, which include amounts previously paid under protest as well as certain costs and fees incurred pursuing the arbitration.

The restructuring charges are for employee severance and related benefit costs incurred as part of a corporate reorganization.

17. Business Segment Information

Kosmos is engaged in a single line of business, which is the exploration and development of oil and gas. At December 31, 2019, the Company had operations in four geographic reporting segments: Ghana, Equatorial Guinea, Mauritania/Senegal and the U.S. Gulf of Mexico. To assess performance of the reporting segments, the Chief Operating Decision Maker ("CODM") reviews capital expenditures. Capital expenditures, as defined by the Company, may not be comparable to similarly titled measures used by other companies and should be considered in conjunction with our consolidated financial statements and notes thereto. Financial information for each area is presented below:

	Ghana	Equatorial Guinea	Mauritania / Senegal	U.S. Gulf of Mexico	Corporate & Other	Eliminations	Total
				(in thousands)			
Year ended December 31, 2019							
Revenues and other income:							
Oil and gas revenue	$ 738,909	$ 300,547	$ —	$ 459,960	$ —	$ —	$ 1,499,416
Gain on sale of assets	—	—	—	—	10,528	—	10,528
Other income, net	5	—	—	1,194	155,866	(157,100)	(35)
Total revenues and other income	738,914	300,547	—	461,154	166,394	(157,100)	1,509,909
Costs and expenses:							
Oil and gas production	188,207	90,607	—	123,799	—	—	402,613
Facilities insurance modifications, net	(24,254)	—	—	—	—	—	(24,254)
Exploration expenses	204	13,350	11,181	115,765	40,455	—	180,955
General and administrative	18,618	6,643	8,222	25,456	159,539	(108,468)	110,010
Depletion, depreciation and amortization	268,866	75,565	62	214,592	4,776	—	563,861
Interest and other financing costs, net(1)	72,226	(634)	(26,537)	21,266	95,887	(7,134)	155,074
Derivatives, net	—	—	—	30,387	41,498	—	71,885
Other expenses, net	40,382	(563)	12,056	2,691	11,580	(41,498)	24,648
Total costs and expenses	564,249	184,968	4,984	533,956	353,735	(157,100)	1,484,792
Income (loss) before income taxes	174,665	115,579	(4,984)	(72,802)	(187,341)	—	25,117
Income tax expense	50,293	49,192	—	(8,419)	(10,172)	—	80,894
Net income (loss)	$ 124,372	$ 66,387	$ (4,984)	$ (64,383)	$ (177,169)	$ —	$ (55,777)
Consolidated capital expenditures	$ 98,285	$ 63,798	$ 12,556	$ 232,891	$ 33,206	$ —	$ 440,736
As of December 31, 2019							
Property and equipment, net	$ 1,487,114	$ 464,420	$ 438,800	$ 1,216,453	$ 35,545	$ —	$ 3,642,332
Total assets	$ 1,654,266	$ 650,607	$ 581,317	$ 3,251,420	$ 12,144,312	$ (13,964,690)	$ 4,317,232

(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(1)	Mauritania / Senegal	U.S. Gulf of Mexico(2)	Corporate & Other	Eliminations(3)	Total
				(in thousands)			
Year ended December 31, 2018							
Revenues and other income:							
Oil and gas revenue	$ 739,070	$ 360,649	$ —	$ 147,596	$ —	$ (360,649)	$ 886,666
Gain on sale of assets	—	7,666	—	—	—	—	7,666
Other income, net	(17)	(238)	—	11	$ 150,635	(142,354)	8,037
Total revenues and other income	739,053	368,077	—	147,607	150,635	(503,003)	902,369
Costs and expenses:							
Oil and gas production	189,104	73,843	—	30,470	5,153	(73,843)	224,727
Facilities insurance modifications, net	6,955	—	—	—	—	—	6,955
Exploration expenses	58,276	38,164	7,262	66,962	131,180	(352)	301,492
General and administrative	19,342	5,351	5,220	10,534	168,542	(109,133)	99,856
Depletion, depreciation and amortization	265,805	134,983	61	59,835	4,134	(134,983)	329,835
Interest and other financing costs, net(3)	86,738	(12)	(25,386)	7,487	39,483	(7,134)	101,176
Derivatives, net	—	—	—	(57,615)	26,185	—	(31,430)
Loss on equity method investments, net	—	—	—	—	—	(72,881)	(72,881)
Other expenses, net	16,414	(814)	(23)	598	3,510	(26,186)	(6,501)
Total costs and expenses	642,634	251,515	(12,866)	118,271	378,187	(424,512)	953,229
Income (loss) before income taxes	96,419	116,562	12,866	29,336	(227,552)	(78,491)	(50,860)
Income tax expense (benefit)	34,494	78,491	—	6,163	2,474	(78,491)	43,131
Net income (loss)	$ 61,925	$ 38,071	$ 12,866	$ 23,173	$ (230,026)	$ —	$ (93,991)
Consolidated capital expenditures	$ 105,942	$ 32,156	$ 11,962	$ 95,993	$ 139,381	$ —	$ 385,434
As of December 31, 2018							
Property and equipment, net	$ 1,698,194	$ 3,919	$ 411,448	$ 1,308,670	$ 37,470	$ —	$ 3,459,701
Total assets	$ 1,930,071	$ 55,302	$ 536,620	$ 3,512,989	$ 10,349,488	$ (12,296,281)	$ 4,088,189

(1) Includes our proportionate share of our equity method investment in KTIPI, including our basis difference which is reflected in depletion, depreciation and amortization for the year ended December 31, 2018, except for capital expenditures. See Note 7 - Equity Method Investments for additional information regarding our equity method investments.

(2) Represents activity commencing September 14, 2018, the DGE acquisition date.

(3) Includes elimination of proportionate consolidation amounts recorded for KTIPI to reconcile to (Gain) loss on equity method investments, net as reported in the consolidated statements of operations.

(4) 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(1)	Mauritania / Senegal	U.S. Gulf of Mexico	Corporate & Other	Eliminations(2)	Total
				(in thousands)			
Year ended December 31, 2017							
Revenues and other income:							
Oil and gas revenue	$ 578,139	$ 27,308	$ —	$ —	$ —	$ (27,308)	$ 578,139
Gain on sale of assets	—	—	—	—	—	—	—
Other income, net	5	147	—	—	$ 219,968	(161,423)	58,697
Total revenues and other income	578,144	27,455	—	—	219,968	(188,731)	636,836
Costs and expenses:							
Oil and gas production	137,584	7,755	—	—	(10,734)	(7,755)	126,850
Facilities insurance modifications, net	(820)	—	—	—	—	—	(820)
Exploration expenses	394	86	71,456	—	144,114	—	216,050
General and administrative	14,836	672	8,298	—	138,661	(94,165)	68,302
Depletion, depreciation and amortization	251,890	11,181	20	—	3,293	(11,181)	255,203
Interest and other financing costs, net(3)	71,592	—	(16,065)	—	29,202	(7,134)	77,595
Derivatives, net	—	—	—	—	59,968	—	59,968
Loss on equity method investments, net	—	—	11,486	—	—	(5,234)	6,252
Other expenses, net	64,768	—	867	—	(376)	(59,968)	5,291
Total costs and expenses	540,244	19,694	76,062	—	364,128	(185,437)	814,691
Income (loss) before income taxes	37,900	7,761	(76,062)	—	(144,160)	(3,294)	(177,855)
Income tax expense (benefit)	18,649	3,294	3	—	26,285	(3,294)	44,937
Net income (loss)	$ 19,251	$ 4,467	$ (76,065)	$ —	$ (170,445)	$ —	$ (222,792)
Consolidated capital expenditures	$ 5,545	$ 1,995	$ (80,929)	$ —	$ 130,821	$ —	$ 57,432
As of December 31, 2017							
Property and equipment, net	$ 1,901,127	$ 1,908	$ 381,422	$ —	$ 33,371	$ —	$ 2,317,828
Total assets	$ 2,263,824	$ 237,835	$ 570,044	$ —	$ 8,671,437	$ (8,550,537)	$ 3,192,603

(1) Includes our proportionate share of our equity method investment in KTIPI, including our basis difference which is reflected in depletion, depreciation and amortization for the year ended December 31, 2017, except for capital expenditures. See Note 7 - Equity Method Investments for additional information regarding our equity method investments.

(2) Includes elimination of proportionate consolidation amounts recorded for KTIPI to reconcile to (Gain) loss on equity method investments, net as reported in the consolidated statements of operations.

(3) 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,		
	2019	2018	2017
	(In thousands)		
Consolidated capital expenditures:			
Consolidated Statements of Cash Flows - Investing activities:			
Oil and gas assets	$ 340,217	$ 213,806	$ 140,495
Other property	11,796	7,935	2,858
Adjustments:			
Changes in capital accruals	33,717	26,669	(6,337)
Exploration expense, excluding unsuccessful well costs and leasehold impairments(1)	93,142	178,293	172,849
Capitalized interest	(28,077)	(28,331)	(30,282)
Proceeds on sale of assets	(16,713)	(13,703)	(222,068)
Other	6,654	765	(83)
Total consolidated capital expenditures	$ 440,736	$ 385,434	$ 57,432

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

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

Net proved oil and gas reserve estimates presented were prepared by Ryder Scott Company, L.P. (“RSC”) for the years ended December 31, 2019, 2018 and 2017. RSC are independent petroleum engineers located in Houston, Texas. RSC has prepared the reserve estimates presented herein and meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to independent reserve engineers for their reserves estimation process.

Net Proved Developed and Undeveloped Reserves

The following table is a summary of net proved developed and undeveloped oil and gas reserves to Kosmos' interest in the Jubilee and TEN fields in Ghana, the U.S. Gulf of Mexico (commencing September 14, 2018, the DGE acquisition date), and our equity method investment offshore Equatorial Guinea.

	Ghana	Equatorial Guinea	Mauritania / Senegal(7)	U.S. Gulf of Mexico	Total Oil	Ghana	Equatorial Guinea	Mauritania / Senegal(7)	U.S. Gulf of Mexico	Total Gas	Kosmos Total	Equity Method Investment-Equatorial Guinea	Total
	Oil, Condensate, NGLs (MMBbls)					Natural Gas (Bcf)					(MMBoe)		
Net proved developed and undeveloped reserves at December 31, 2016(1)	74	—	—	—	74	15	—	—	—	15	77	—	77
Extensions and discoveries	1	—	—	—	1	—	—	—	—	—	1	—	1
Production	(11)	—	—	—	(11)	(1)	—	—	—	(1)	(11)	(1)	(12)
Revision in estimate(2)	18	—	—	—	18	35	—	—	—	35	24	—	24
Purchases of minerals-in-place(3)	—	—	—	—	—	—	—	—	—	—	—	21	21
Net proved developed and undeveloped reserves at December 31, 2017(1)	82	—	—	—	82	49	—	—	—	49	89	21	110
Extensions and discoveries	—	—	—	—	—	—	—	—	—	—	—	—	—
Production	(11)	—	—	(2)	(13)	(1)	—	—	(2)	(3)	(14)	(5)	(19)
Revision in estimate	11	—	—	—	11	(1)	—	—	—	(1)	11	10	21
Purchases of minerals-in-place(5)	—	—	—	47	47	—	—	—	40	40	54	—	54
Net proved developed and undeveloped reserves at December 31, 2018(1)	82	—	—	45	127	47	—	—	38	85	141	26	167
Extensions and discoveries		—	—		—		—	—		—	—	—	—
Production	(11)	(4)	—	(8)	(23)	(1)	—	—	(6)	(7)	(24)	—	(24)
Revision in estimate(4)	17	6	—	3	26	(1)	(2)	—	3	—	26	—	26
Purchases of minerals-in-place(6)		24	—		24		14	—		14	26	(26)	—
Net proved developed and undeveloped reserves at December 31, 2019(1)	88	26	—	40	154	45	12	—	35	92	169	—	169
Proved developed reserves(1)													
December 31, 2016	64	—	—	—	64	13	—	—	—	13	66	—	66
December 31, 2017	59	—	—	—	59	38	—	—	—	38	65	20	85
December 31, 2018	48	—	—	33	81	33	—	—	24	57	91	25	116
December 31, 2019	47	23	—	34	104	31	12	—	28	71	116	—	116
Proved undeveloped reserves(1)													
December 31, 2016	10	—	—	—	10	2	—	—	—	2	11	—	11
December 31, 2017	23	—	—	—	23	11	—	—	—	11	24	1	25
December 31, 2018	33	—	—	12	45	14	—	—	13	28	50	1	51
December 31, 2019	41	3	—	6	50	14	—	—	7	21	53	—	53

(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 increase in proved reserves is a result of a 16 MMBbl increase associated in Jubilee related to the approval of the Greater Jubilee Full Field Development Plan (GJFFDP) and an 8 MMBoe increase associated with positive revisions to the TEN fields.

(3) The increase in purchase of minerals in place is related to Equatorial Guinea, representing the reserves associated with our equity method investment.

(4) The increase in proved reserves is a result of an increase of 8.2 MMBbl in Greater Jubilee related to positive drilling results and subsequent increased original oil in place, and optimized development plan. Changes at TEN include a positive revision of 8.8 MMBoe related to original oil in place adjustments based on the latest static modeling, and development plan updates. Changes at Equatorial Guinea include an increase of 6.3 MMBbl due to production optimization and plans for new drilling. Changes at the Gulf of Mexico (GoM) include an increase of 2.9 MMBoe related to strong performance of certain fields and the Gladden Deep discovery.

(5) The increase in purchase of minerals in place is related to the DGE acquisition completed in September 2018.

(6) We disclosed our share of reserves that were accounted for by the equity method. Effective of January 1, 2019, our outstanding shares in KTIPI were transferred to Trident in exchange for a 40.4% undivided participating interest in the Ceiba Field and Okume Complex. As a result, our interest in the Ceiba Field and Okume Complex is accounted for under the proportionate consolidation method of accounting going forward.

(7) The Tortue Phase 1 SPA was signed on February 11, 2020, resulting in approximately 100 MMBoe of proved undeveloped reserves being recognized at that time as evaluated by the company's independent reserve auditor Ryder Scott, LP.

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 2019. The average price is adjusted for crude handling, transportation fees, quality, and a regional price differential.

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

Capitalized Costs Related to Oil and Gas Activities

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

	Ghana	Equatorial Guinea	Mauritania / Senegal	U.S. Gulf of Mexico	Other(1)	Kosmos Total	Equity Method Investment-Equatorial Guinea(2)	Total
				(In millions)				
As of December 31, 2019								
Unproved properties	—	119	439	233	23	814	—	814
Proved properties	3,250	411	—	1,244	—	4,905	—	4,905
	3,250	530	439	1,477	23	5,719	—	5,719
Accumulated depletion	(1,763)	(66)	—	(265)	—	(2,094)	—	(2,094)
Net capitalized costs	1,487	464	439	1,212	23	3,625	—	3,625
As of December 31, 2018								
Unproved properties	—	4	411	319	26	760	—	760
Proved properties	3,191	—	—	1,045	—	4,236	2,850	7,086
	3,191	4	411	1,364	26	4,996	2,850	7,846
Accumulated depletion	(1,493)	—	—	(58)	—	(1,551)	(2,717)	(4,268)
Net capitalized costs	1,698	4	411	1,306	26	3,445	133	3,578

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

(2) Represents 50% interest in KTIPI's capitalized costs related to oil and gas activities.

Costs Incurred in Oil and Gas Activities

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

	Ghana	Equatorial Guinea	Mauritania / Senegal	U.S. Gulf of Mexico	Other(1)	Kosmos Total	Equity Method Investment-Equatorial Guinea(2)	Total
				(In millions)				
Year ended December 31, 2019								
Property acquisition:								
Unproved	$ —	$ 11	$ 2	$ 15	$ —	$ 28	$ —	$ 28
Proved	—	—	—	—	—	—	—	—
Exploration	—	41	26	122	38	227	—	227
Development	59	126	11	91	—	287	—	287
Total costs incurred	$ 59	$ 178	$ 39	$ 228	$ 38	$ 542	$ —	$ 542
Year ended December 31, 2018								
Property acquisition:								
Unproved	$ —	$ 2	$ —	$ 303	$ 1	$ 306	$ —	$ 306
Proved(3)	—	—	—	1,038	—	1,038	—	1,038
Exploration	3	30	33	69	137	272	—	272
Development	111	—	4	21	—	136	—	136
Total costs incurred	$ 114	$ 32	$ 37	$ 1,431	$ 138	$ 1,752	$ —	$ 1,752
Year ended December 31, 2017								
Property acquisition:								
Unproved	$ —	$ 1	$ 3	$ —	$ 6	$ 10	$ —	$ 10
Proved	—	—	—	—	231	231	—	231
Exploration(4)	15	—	(69)	—	125	71	—	71
Development	1	—	—	—	—	1	—	1
Total costs incurred	$ 16	$ 1	$ (66)	$ —	$ 362	$ 313	$ —	$ 313

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

(2) For year ended December 31, 2017, represents 50% interest in KTIPI costs incurred from the date of acquisition through December 31, 2017.

(3) Represents cash paid to acquire 50% interest in KTIPI.

(4) Mauritania/Senegal is net of the farm-out to BP in 2017.

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 2019. 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(2)	U.S. Gulf of Mexico	Equity Method Investment- Equatorial Guinea	Total
			(In millions)			
At December 31, 2019						
Future cash inflows	$ 5,546	$ 1,650	$ —	$ 2,205	$ —	$ 9,401
Future production costs	(1,683)	(675)	—	(312)	—	$ (2,670)
Future development costs	(736)	(400)	—	(393)	—	$ (1,529)
Future tax expenses	(1,026)	(317)	—	(123)	—	(1,466)
Future net cash flows	2,101	258	—	1,377	—	3,736
10% annual discount for estimated timing of cash flows	(675)	36	—	(278)	—	(917)
Standardized measure of discounted future net cash flows	$ 1,426	$ 294	$ —	$ 1,099	$ —	$ 2,819
At December 31, 2018						
Future cash inflows	$ 5,882	$ —	$ —	$ 2,951	$ 1,735	$ 10,568
Future production costs	(1,613)	—	—	(338)	(583)	(2,534)
Future development costs	(928)	—	—	(467)	(378)	(1,773)
Future tax expenses	(1,052)	—	—	(379)	(416)	(1,847)
Future net cash flows	2,289	—	—	1,767	358	4,414
10% annual discount for estimated timing of cash flows	(749)	—	—	(397)	33	(1,113)
Standardized measure of discounted future net cash flows	$ 1,540	$ —	$ —	$ 1,370	$ 391	$ 3,301
At December 31, 2017						
Future cash inflows	$ 4,473	$ —	$ —	$ —	$ 1,003	$ 5,476
Future production costs	(1,925)	—	—	—	(473)	(2,398)
Future development costs	(1,059)	—	—	—	(296)	(1,355)
Future Ghanaian tax expenses(1)	(203)	—	—	—	(225)	(428)
Future net cash flows	1,286	—	—	—	9	1,295
10% annual discount for estimated timing of cash flows	(315)				121	(194)
Standardized measure of discounted future net cash flows	$ 971	$ —	$ —	$ —	$ 130	$ 1,101

(1) The Company was a tax exempt company incorporated pursuant to the laws of Bermuda at December 31, 2017. The Company was not subject to future income tax expense related to its proved oil and gas reserves levied at a corporate parent level. Accordingly, the Company's Standardized Measure for the years ended December 31, 2018 and 2017, respectively, only reflect the effects of future tax expense levied at an asset level.

(2) The Tortue Phase 1 SPA was signed on February 11, 2020, resulting in approximately 100 MMBoe of proved undeveloped reserves being recognized at that time as evaluated by the company's independent reserve auditor Ryder Scott, LP.

Changes in the Standardized Measure for Discounted Cash Flows

	Ghana	Equatorial Guinea	Mauritania / Senegal(3)	U.S. Gulf of Mexico	Equity Method Investment- Equatorial Guinea	Total
			(In millions)			
Balance at December 31, 2016	$ 846	$ —	$ —	$ —	$ —	$ 846
Purchase of minerals in place	—	—	—	—	146	146
Sales and transfers 2017	(451)	—	—	—	(16)	(467)
Extensions and discoveries	21	—	—	—	—	21
Net changes in prices and costs	485	—	—	—	—	485
Previously estimated development costs incurred during the period	6	—	—	—	—	6
Net changes in development costs	(388)	—	—	—	—	(388)
Revisions of previous quantity estimates	415	—	—	—	—	415
Net changes in tax expenses(1)	(8)	—	—	—	—	(8)
Accretion of discount	98	—	—	—	—	98
Changes in timing and other	(53)	—	—	—	—	(53)
Balance at December 31, 2017	$ 971	$ —	$ —	$ —	$ 130	$ 1,101
Purchase of minerals in place	—	—	—	1,487	—	1,487
Sales and transfers 2018	(545)	—	—	(117)	(287)	(949)
Extensions and discoveries	—	—	—	—	—	—
Net changes in prices and costs	1,137	—	—	—	271	1,408
Previously estimated development costs incurred during the period	105	—	—	—	—	105
Net changes in development costs	15	—	—	—	(29)	(14)
Revisions of previous quantity estimates	398	—	—	—	385	783
Net changes in tax expenses	(565)	—	—	—	(136)	(701)
Accretion of discount	112	—	—	—	30	142
Changes in timing and other	(88)	—	—	—	27	(61)
Balance at December 31, 2018	$ 1,540	$ —	$ —	$ 1,370	$ 391	$ 3,301
Purchase of minerals in place(2)	—	391	—	—	(391)	—
Sales and transfers 2019	(568)	(210)	—	(336)	—	(1,114)
Extensions and discoveries	—	—	—	(14)	—	(14)
Net changes in prices and costs	(352)	(151)	—	(401)	—	(904)
Previously estimated development costs incurred during the period	97	11	—	109	—	217
Net changes in development costs	44	(57)	—	(43)	—	(56)
Revisions of previous quantity estimates	474	187	—	109	—	770
Net changes in tax expenses	(23)	11	—	231	—	219
Accretion of discount	224	69	—	167	—	460
Changes in timing and other	(10)	43	—	(93)	—	(60)
Balance at December 31, 2019	$ 1,426	$ 294	$ —	$ 1,099	$ —	$ 2,819

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(1) The Company was a tax exempt company incorporated pursuant to the laws of Bermuda at December 31, 2017 and 2016. The Company was not subject to future income tax expense related to its proved oil and gas reserves levied at a corporate parent level. Accordingly, the Company's Standardized Measure for the years ended December 31, 2018 and 2017, respectively, only reflect the effects of future tax expense levied at an asset level.

(2) We disclosed our share of reserves that were accounted for by the equity method. Effective of January 1, 2019, our outstanding shares in KTIPI were transferred to Trident in exchange for a 40.4% undivided participating interest in the Ceiba Field and Okume Complex. As a result, our interest in the Ceiba Field and Okume Complex is accounted for under the proportionate consolidation method of accounting going forward.

(3) The Tortue Phase 1 SPA was signed on February 11, 2020, resulting in approximately 100 MMBoe of proved undeveloped reserves being recognized at that time as evaluated by the company's independent reserve auditor Ryder Scott, LP.

KOSMOS ENERGY LTD.

Supplemental Quarterly Financial Information (Unaudited)

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
	(In thousands, except per share data)			
2019				
Revenues and other income	$ 296,790	$ 395,934	$ 356,970	$ 460,215
Costs and expenses	358,370	346,495	317,435	462,492
Net income (loss)	(52,906)	16,837	16,065	(35,773)
Net income (loss) per share:				
Basic(1)	(0.13)	0.04	0.04	(0.09)
Diluted(1)	(0.13)	0.04	0.04	(0.09)
2018				
Revenues and other income	$ 127,177	$ 215,473	$ 250,219	$ 309,500
Costs and expenses	201,751	364,091	364,912	22,475
Net income (loss)	(50,226)	(103,273)	(126,057)	185,565
Net income (loss) per share:				
Basic(1)	(0.13)	(0.26)	(0.31)	0.44
Diluted(1)	(0.13)	(0.26)	(0.31)	0.43

(1) The sum of the quarterly earnings per share information may not add to the annual earnings per share information as a result of rounding.

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, 2019, 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, 2019 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.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated herein by reference to the 2020 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2019.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2020 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2019.

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 2020 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2019.

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

The information required by this item is incorporated herein by reference to the 2020 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2019.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the 2020 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2019.

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 2019, 2018 and 2017 (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, 2019	December 31, 2018
Assets		
Current assets:		
Cash and cash equivalents	$ 6,422	$ 6,776
Receivables from subsidiaries	3,819	2,890
Note receivable from subsidiary	—	7,941
Prepaid expenses and other	428	313
Total current assets	10,669	17,920
Investment in subsidiaries at equity	1,159,560	1,432,468
Long-term note receivable from subsidiary	518,844	607,943
Deferred financing costs, net of accumulated amortization of $14,681 and $12,065 at December 31, 2019 and December 31, 2018, respectively	6,321	8,937
Restricted cash	305	305
Long-term deferred tax asset	17,265	(1,132)
Total assets	$ 1,712,964	$ 2,066,441
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable	$ —	$ 975
Accrued liabilities	11,942	18,972
Total current liabilities	11,942	19,947
Long-term debt	640,856	836,016
Long-term note payable to subsidiary	217,000	269,000
Other long-term liabilities	1,464	—
Shareholders' equity:		
Preference shares, $0.01 par value; 200,000,000 authorized shares; zero issued at December 31, 2019 and December 31, 2018	—	—
Common stock, $0.01 par value; 2,000,000,000 authorized shares; 445,779,367 and 442,914,675 issued at December 31, 2019 and December 31, 2018, respectively	4,458	4,429
Additional paid-in capital	2,297,221	2,341,249
Accumulated deficit	(1,222,970)	(1,167,193)
Treasury stock, at cost, 44,263,269 shares at December 31, 2019 and 2018, respectively	(237,007)	(237,007)
Total shareholders' equity	841,702	941,478
Total liabilities and shareholders' equity	$ 1,712,964	$ 2,066,441

KOSMOS ENERGY LTD.

CONDENSED PARENT COMPANY STATEMENTS OF OPERATIONS

(In thousands)

	Years Ended December 31,		
	2019	**2018**	**2017**
Revenues and other income:			
Oil and gas revenue	$ —	$ —	$ —
Total revenues and other income	—	—	—
Costs and expenses:			
General and administrative	40,840	47,279	51,544
General and administrative recoveries—related party	(30,822)	(36,197)	(40,266)
Interest and other financing costs, net	86,104	66,055	55,596
Interest and other financing costs, net—related party	(7,144)	(7,941)	—
Other expenses, net	10	49	40
Equity in (earnings) losses of subsidiaries	(15,064)	23,614	155,878
Total costs and expenses	73,924	92,859	222,792
Loss before income taxes	(73,924)	(92,859)	(222,792)
Income tax expense	(18,147)	1,132	—
Net loss	$ (55,777)	$ (93,991)	$ (222,792)
Dividends declared per common share	$ 0.1808	$ —	$ —

KOSMOS ENERGY LTD.

CONDENSED PARENT COMPANY STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31,		
	2019	2018	2017
Operating activities			
Net loss	$ (55,777)	$ (93,991)	$ (222,792)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Equity in (earnings) losses of subsidiaries	(15,064)	23,614	155,878
Equity-based compensation	32,370	35,230	39,913
Depreciation and amortization	5,039	7,292	3,070
Deferred income taxes	(18,397)	1,132	—
Loss on extinguishment of debt	22,913	—	—
Other	—	268	3,884
Changes in assets and liabilities:			
Decrease in receivables	427	1,234	986
(Increase) decrease in prepaid expenses and other	(115)	(23)	127
(Increase) decrease due to/from related party	43,974	(42,163)	14,463
Increase (decrease) in accounts payable and accrued liabilities	(8,754)	816	1,179
Net cash provided by (used in) operating activities	6,616	(66,591)	(3,292)
Investing activities			
Investment in subsidiaries	287,972	(36,192)	4,691
Net cash provided by (used in) investing activities	287,972	(36,192)	4,691
Financing activities			
Borrowings under long-term debt	—	400,000	—
Payments on long-term debt	(325,000)	(75,000)	—
Net proceeds from issuance of senior notes	641,875	—	—
Redemption of senior secured notes	(535,338)	—	—
Purchase of treasury stock / tax withholdings	(1,983)	(206,051)	(2,194)
Dividends	(72,599)	—	—
Deferred financing costs	(1,897)	(9,382)	—
Net cash provided by (used in) financing activities	(294,942)	109,567	(2,194)
Net increase (decrease) in cash and cash equivalents	(354)	6,784	(795)
Cash, cash equivalents and restricted cash at beginning of period	7,081	297	1,092
Cash, cash equivalents and restricted cash at end of period	$ 6,727	$ 7,081	$ 297
Non-cash activity:			
Issuance of common stock for related party receivable	$ —	$ 307,944	$ —

Schedule II

Kosmos Energy Ltd.

Valuation and Qualifying Accounts

For the Years Ended December 31, 2019, 2018 and 2017

Description	Balance January 1,	Additions: Charged to Costs and Expenses	Additions: Charged To Other Accounts	Deductions From Reserves	Balance December 31,
2019					
Allowance for doubtful receivables	$ 1,211	$ 1,324	$ 228	$ (15)	$ 2,748
Allowance for deferred tax assets	$ 156,860	$ 44,889	$ —	$ —	$ 201,749
2018					
Allowance for doubtful receivables	$ —	$ 1,211	$ —	$ —	$ 1,211
Allowance for deferred tax assets	$ 93,525	$ 63,335	$ —	$ —	$ 156,860
2017					
Allowance for doubtful receivables	$ 574	$ 77	$ —	$ (651)	$ —
Allowance for deferred tax assets	$ 87,517	$ 6,008	$ —	$ —	$ 93,525

Schedules other than Schedule I and Schedule II have been omitted because they are not applicable or the required information is presented in the consolidated financial statements or the notes to consolidated financial statements.

(3) Exhibits

See “Index to Exhibits” on page 139 for a description of the exhibits filed as part of this report.

Item 16. Form 10-K Summary

None

SIGNATURES

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

KOSMOS ENERGY LTD.

Date: February 24, 2020 By: /s/ Thomas P. Chambers

Thomas P. Chambers
Senior Vice President and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Andrew G. Inglis Andrew G. Inglis	Chairman of the Board of Directors and Chief Executive Officer (Principal Executive Officer)	February 24, 2020
/s/ Thomas P. Chambers Thomas P. Chambers	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 24, 2020
/s/ Ronald Glass Ronald Glass	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 24, 2020
/s/ Lisa Davis Lisa Davis	Director	February 24, 2020
/s/ Sir Richard B. Dearlove Sir Richard B. Dearlove	Director	February 24, 2020
/s/ Deanna L. Goodwin Deanna L. Goodwin	Director	February 24, 2020
/s/ Adebayo O. Ogunlesi Adebayo O. Ogunlesi	Director	February 24, 2020
/s/ Steven M. Sterin Stevin M. Sterin	Director	February 24, 2020

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	Bylaws of the Company (filed as Exhibit 3.2 to the Company's Form 8-K12g-3 filed December 31, 2018 (File No. 000-56014), 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
	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).
10.11	Production Sharing Contract relating to Block 6 Offshore Sao Tome between the Democratic Republic of Sao Tome and Principe and Galp Energia São Tomé e Príncipe, Unipessoal, LDA dated October 26, 2015 (filed as Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, and incorporated herein by reference).

Exhibit Number	Description of Document
10.12	Addendum, dated November 9, 2015, to the Production Sharing Contract relating to Block 6 Offshore Sao Tome between the Democratic Republic of Sao Tome and Principe and Galp Energia São Tomé e Príncipe, Unipessoal, LDA dated October 26, 2015 (filed as Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, and incorporated herein by reference).
10.13	Production Sharing Contract relating to Block 10 Offshore Sao Tome between the Democratic Republic of Sao Tome and Principe, BP Exploration (STP) Limited and Kosmos Energy Sao Tome and Principe dated March 9, 2018 (filed as Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, and incorporated herein by reference).
10.14	First Addendum, dated December 17, 2015, to the Production Sharing Contract relating to Block 11 Offshore Sao Tome between the Democratic Republic of Sao Tome and Kosmos Energy Sao Tome and Principe dated July 23, 2014 (filed as Exhibit 10.11 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, and incorporated herein by reference).
10.15	Production Sharing Contract relating to Block 12 Offshore Sao Tome between the Democratic Republic of Sao Tome and Principe and Equator Exploration STP Block 12 Limited dated February 19, 2016 (filed as Exhibit 10.12 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, and incorporated herein by reference).
10.16	First Amendment, dated March 31, 2016, to the Production Sharing Contract between the Democratic Republic of Sao Tome and Principe, Equator Exploration STP Block 12 Limited and Kosmos Energy Sao Tome and Principe dated February 19, 2016 (filed as Exhibit 10.14 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, and incorporated herein by reference).
10.17	Production Sharing Contract relating to Block 13 Offshore Sao Tome between the Democratic Republic of Sao Tome and Principe, BP Exploration (STP) Limited and Kosmos Energy Sao Tome and Principe dated March 9, 2018 (filed as Exhibit 10.9 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, and incorporated herein by reference).
	Senegal
10.18	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).
10.19	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).
10.20	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).
	Suriname
10.21	Production Sharing Contract for Petroleum Exploration, Development and Production relating to Block 42 Offshore Suriname between Staatsolie Maatshappij Suriname N.V. and Kosmos Energy Suriname dated December 13, 2011 (filed as Exhibit 10.20 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.22	Production Sharing Contract for Petroleum Exploration, Development and Production relating to Block 45 Offshore Suriname between Staatsolie Maatshappij Suriname N.V. and Kosmos Energy Suriname dated December 13, 2011 (filed as Exhibit 10.21 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
	Mauritania
10.23	Exploration and Production Contract between The Islamic Republic of Mauritania and Kosmos Energy Mauritania (Bloc C8) dated April 5, 2012 (filed as Exhibit 10.17 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.24	Exploration and Production Contract between The Islamic Republic of Mauritania and Kosmos Energy Mauritania (Bloc C12) dated April 5, 2012 (filed as Exhibit 10.18 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.25	Exploration and Production Contract between The Islamic Republic of Mauritania and Kosmos Energy Mauritania (Bloc C13) dated April 5, 2012 (filed as Exhibit 10.19 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.26	Exploration and Production Contract between The Islamic Republic of Mauritania and Kosmos Energy Mauritania (Bloc C6) dated October 11, 2016 (filed as Exhibit 10.41 to the Company's Annual Report on Form 10-K of the year ended December 31, 2016, and incorporated herein by reference).

Exhibit Number	Description of Document
10.27	Exploration and Production Contract between The Islamic Republic of Mauritania and Tullow Mauritania Limited (Bloc C18) dated May 17, 2012 (filed as Exhibit 10.42 to the Company's Annual Report on Form 10-K of the year ended December 31, 2017, and incorporated herein by reference).
	Equatorial Guinea
10.28	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).
10.29	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).
10.30	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).
10.31	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).
10.32	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).
10.33	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).
10.34	Production Sharing Contract relating to Block S Offshore Republic of Equatorial Guinea between the Republic of Equatorial Guinea, Guinea Ecuatorial de Petroleos and Kosmos Energy Equatorial Guinea dated October 10, 2017 (filed as Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, and incorporated herein by reference).
10.35	Production Sharing Contract relating to Block W 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 10.7 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, and incorporated herein by reference).
10.36	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).
	Cote d'Ivoire
10.37	Hydrocarbons Production Sharing Agreement between The Republic of Cote d'Ivoire, BP Exploration Operating Company Limited and Kosmos Energy Cote d'Ivoire (Block CI-526) dated December 21, 2017 (filed as Exhibit 10.44 to the Company's Annual Report on Form 10-K of the year ended December 31, 2017, and incorporated herein by reference).
10.38	Hydrocarbons Production Sharing Agreement between The Republic of Cote d'Ivoire, BP Exploration Operating Company Limited and Kosmos Energy Cote d'Ivoire (Block CI-602) dated December 21, 2017 (filed as Exhibit 10.45 to the Company's Annual Report on Form 10-K of the year ended December 31, 2017, and incorporated herein by reference).
10.39	Hydrocarbons Production Sharing Agreement between The Republic of Cote d'Ivoire, BP Exploration Operating Company Limited and Kosmos Energy Cote d'Ivoire (Block CI-603) dated December 21, 2017 (filed as Exhibit 10.46 to the Company's Annual Report on Form 10-K of the year ended December 31, 2017, and incorporated herein by reference).

Exhibit Number	Description of Document
10.40	Hydrocarbons Production Sharing Agreement between The Republic of Cote d'Ivoire, BP Exploration Operating Company Limited and Kosmos Energy Cote d'Ivoire (Block CI-707) dated December 21, 2017 (filed as Exhibit 10.47 to the Company's Annual Report on Form 10-K of the year ended December 31, 2017, and incorporated herein by reference).
10.41	Hydrocarbons Production Sharing Agreement between The Republic of Cote d'Ivoire, BP Exploration Operating Company Limited and Kosmos Energy Cote d'Ivoire (Block CI-708) dated December 21, 2017 (filed as Exhibit 10.48 to the Company's Annual Report on Form 10-K of the year ended December 31, 2017, and incorporated herein by reference).
	Namibia
10.42	Petroleum Agreement between the Government of the Republic of Namibia and Signet Petroleum Limited Cricket Investments (PTY) LTD National Petroleum Corporation of Namibia (Block 2914B) dated June 2011 (filed as Exhibit 10.42 to the Company's Annual Report on Form 10-K of the year ended December 31, 2018, and incorporated herein by reference).
10.43	Addendum to Petroleum Agreement between The Government of the Republic of Namibia and Shell Namibia Upstream B.V. and National Petroleum Corporation of Namibia dated June 17, 2011 (filed as Exhibit 10.43 to the Company's Annual Report on Form 10-K of the year ended December 31, 2018, and incorporated herein by reference).
10.44	Addendum II to Petroleum Agreement between The Government of the Republic of Namibia and Shell Namibia Upstream B.V. and National Petroleum Corporation of Namibia dated June 17, 2011 (filed as Exhibit 10.44 to the Company's Annual Report on Form 10-K of the year ended December 31, 2018, and incorporated herein by reference).
	South Africa
10.45	Exploration Right Contract relating to the Northern Cape Ultra Deep Block Offshore South Africa between the Republic of South Africa and OK Energy Limited dated January 10, 2019 (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2019, and incorporated herein by reference).
	Greater Tortue Ahmeyim
10.46*† †	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
	Financing Agreements
10.47	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).
10.48	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).
10.49	Amended and Restated Revolving Credit Facility Agreement, dated August 6, 2018, among Kosmos Energy Ltd., as Original Borrower, certain of its subsidiaries listed therein, as Guarantors, ING Bank N.V., as Facility Agent, Crédit Agricole Corporate and Investment Bank, as Security and Intercreditor Agent, and the financial institutions listed therein, as Lenders (filed as Exhibit 1.1 to the Company's Current Report on Form 8-K filed August 7, 2018 (File No. 001-35167), and incorporated herein by reference).
	Agreements with Shareholders and Directors
10.50	Form of Director Indemnification Agreement (filed as Exhibit 10.27 to the Company's Registration Statement on Form S-1/A filed April 14, 2011 (File No. 333-171700), and incorporated herein by reference).
10.51	Shareholders Agreement, dated as of May 10, 2011, among Kosmos Energy Ltd. and the other parties signatory thereto (filed as Exhibit 9.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2012, and incorporated herein by reference) (the "Shareholders Agreement").
10.52	Amended and Restated Registration Rights Agreement, dated as of October 7, 2009, among Kosmos Energy Holdings and the other parties signatory thereto (filed as Exhibit 10.32 to the Company's Annual Report on Form 10-K for the year ended December 31, 2012, and incorporated herein by reference).

Exhibit Number	Description of Document
10.53	Joinder Agreement to the Registration Rights Agreement, dated as of May 10, 2011, among Kosmos Energy Ltd. and the other parties signatory thereto (filed as Exhibit 10.33 to the Company's Annual Report on Form 10-K for the year ended December 31, 2012, and incorporated herein by reference).
10.54	Amendment No. 1 to the Registration Rights Agreement, dated as of February 8, 2013, among Kosmos Energy Ltd. and the other parties signatory thereto (filed as Exhibit 10.34 to the Company's Annual Report on Form 10-K for the year ended December 31, 2012, and incorporated herein by reference).
	Management Contracts/Compensatory Plans or Arrangements
10.55†	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).
10.56†	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).
10.57†	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).
10.58†	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).
10.59†	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).
10.60†	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).
10.61†	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).
10.62†	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).
10.63†	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).
10.64†	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).
10.65†	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).
10.66†	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).
10.67†	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).
10.68†	Assignment Agreement, dated April 16, 2014, between Kosmos Energy, LLC and Brian F. Maxted (filed as Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2014, and incorporated herein by reference).
10.69†	Exit Agreement between Kosmos Energy, LLC and Brian F. Maxted dated March 1, 2019 (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2019, and incorporated herein by reference).
10.70†	Offer Letter between Kosmos Energy Gulf of Mexico, LLC and Richard R. Clark dated August 3, 2018 (filed as Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2019, and incorporated herein by reference).
10.71†	Offer Letter, dated October 16, 2014, between Kosmos Energy, LLC and Thomas P. Chambers (filed as Exhibit 10.60 to the Company's Annual Report on Form 10-K for the year ended December 31, 2014, and incorporated herein by reference).
10.72†	Kosmos Energy Ltd. Change in Control Severance Policy for U.S. Employees, dated December 19, 2013 (filed as Exhibit 10.66 to the Company's Annual Report on Form 10-K for the year ended December 31, 2013, and incorporated herein by reference).
10.73†*	Offer Letter, dated November 12, 2019, between Kosmos Energy, LLC and Ronald Glass
	DGE Acquisition

Exhibit Number	Description of Document
10.74	Securities Purchase Agreement by and among DGE Group Series Holdco, LLC, and each of its three designated series, DGE Group Series Holdco, LLC, Series I, DGE Group Series Holdco, LLC, Series, II, DGE Group Series Holdco, LLC, Series III, and Kosmos Energy Gulf of Mexico, LLC dated August 3, 2018 (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed November 5, 2018 (File No. 001-35167), and incorporated herein by reference).
	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).
21.1*	List of Subsidiaries.
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of Ryder Scott Company, L.P.
31.1*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Report of Ryder Scott Company, L.P. - Ghana, Equatorial Guinea, U.S. Gulf of Mexico 12-31-19
99.2*	Report of Ryder Scott Company, L.P. - GTA 1-31-2020
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.

DESCRIPTION OF THE REGISTRANT'S SECURITIES REGISTERED PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

The following descriptions are summaries of the material terms of the certificate of incorporation and bylaws of Kosmos Energy Ltd. (the "Company"), filed as Exhibits 3.1 and 3.2 to our Annual Report on Form 10-K, and the applicable provisions of the General Corporation Law of the State of Delaware ("DGCL"). This summary does not purport to be complete and is subject to, and is qualified in its entirety, by the provisions of our certificate of incorporation, by laws and DGCL.

Authorized Capital Stock

Our authorized capital stock consists of 2,000,000,000 shares of common stock, par value $0.01 per share, and 200,000,000 shares of preferred stock, par value $0.01 per share, all of which preferred stock is undesignated. Unless our board of directors determines otherwise, we will issue all shares of our capital stock in uncertificated form.

Common Stock

Common stock outstanding. As of February 14, 2020 there were 405,098,215 shares of common stock outstanding. All outstanding shares of common stock are fully paid and non-assessable.

Voting rights. The holders of common stock are entitled to one vote per share on all matters to be voted upon by the stockholders.

Dividend rights. Subject to preferences that may be applicable to any outstanding preferred stock, the holders of common stock are entitled to receive ratably such dividends, if any, as may be declared from time to time by the board of directors out of funds legally available therefor.

Rights upon liquidation. In the event of liquidation, dissolution or winding up of the Company, the holders of common stock are entitled to share ratably in all assets remaining after payment of liabilities, subject to prior distribution rights of preferred stock, if any, then outstanding.

Other rights. The holders of our common stock have no preemptive or conversion rights or other subscription rights. There are no redemption or sinking fund provisions applicable to the common stock.

Preferred Stock

Our board of directors has the authority to issue the preferred stock in one or more series and to fix the rights, preferences, privileges and restrictions thereof, including dividend rights, dividend rates, conversion rights, voting rights, terms of redemption, redemption prices, liquidation preferences and the number of shares constituting any series or the designation of such series, without further vote or action by the stockholders.

The issuance of preferred stock may have the effect of delaying, deferring or preventing a change in control of the Company without further action by the stockholders and may adversely affect the voting and other rights of the holders of common stock. As of February 14, 2020 there were no shares of preferred stock outstanding. At present, the Company has no plans to issue any of the preferred stock.

Board Composition

Our board of directors shall consist of not less than five and not more than 15 directors, as determined by the board of directors.

Election and Removal of Directors

No director may be removed except for cause, and directors may be removed for cause by an affirmative vote of shares representing a majority of the shares then entitled to vote at an election of directors. Any vacancy occurring on the board of directors and any newly created directorship may be filled only by a majority of the remaining directors in office.

Staggered Board

Our board of directors is divided into three classes serving staggered three-year terms. At each annual meeting of stockholders, directors will be elected to succeed the class of directors whose terms have expired. This classification of our board of directors could have the effect of increasing the length of time necessary to change the composition of a majority of the board of directors. In general, at least two annual meetings of stockholders will be necessary for stockholders to effect a change in a majority of the members of the board of directors.

Proceedings of Board of Directors

Our bylaws provide that our business shall be managed by or under the direction of our board of directors. Our board of directors may act by the affirmative vote of a majority of the directors present at a meeting at which a quorum is present. A majority of the total number of directors then in office shall constitute a quorum. The board may also act by unanimous written consent.

Duties of Directors

Under Delaware law, the business and affairs of a corporation are managed by or under the direction of its board of directors. In exercising their powers, directors are charged with a duty of care and a duty of loyalty. The duty of care requires that directors act in an informed and deliberate manner and to inform themselves, prior to making a business decision, of all relevant material information reasonably available to them. The duty of care also requires that directors exercise care in overseeing the conduct of corporate employees. The duty of loyalty is the duty to act in good faith, not out of self-interest, and in a manner which the director reasonably believes to be in the best interests of the shareholders. A party challenging the propriety of a decision of a board of directors bears the burden of rebutting the presumptions afforded to directors by the "business judgment rule." If the presumption is not rebutted, the business judgment rule attaches to protect the directors and their decisions. Where, however, the presumption is rebutted, the directors bear the burden of demonstrating the fairness of the relevant transaction. Notwithstanding the foregoing, Delaware courts subject directors' conduct to enhanced scrutiny in respect of defensive actions taken in response to a threat to corporate control and approval of a transaction resulting in a sale of control of the Company.

Interested Directors

Under Delaware law, such a contract or arrangement is voidable unless it is approved by a majority of disinterested directors or by a vote of shareholders, in each case if the material facts as to the interested director's relationship or interests are disclosed or are known to the disinterested directors or shareholders, or such contract or arrangement is fair to the Company as of the time it is approved or ratified. Additionally, such interested director could be held liable for a transaction in which such director derived an improper personal benefit.

Limits on Written Consents

Our certificate of incorporation and our bylaws provide that holders of our common stock will not be able to act by written consent without a meeting.

Stockholder Meetings

Our certificate of incorporation and our bylaws provide that special meetings of our stockholders may be called by the chairman of the board of directors whenever in his or her judgment such a meeting is necessary and by the secretary at the request in writing of holders of record of not less than ten percent of the total voting power of all outstanding securities of the Company generally entitled to vote in the election of directors, voting together as a single class.

Amendment of Certificate of Incorporation

The Company reserves the right to amend the certificate of incorporation in any manner permitted by Delaware law and all rights and powers conferred upon stockholders, directors and officers herein are granted subject to this reservation. Notwithstanding the foregoing, the provisions set forth in "—Voting Rights," "—Bylaws," "—Board of Directors," "—Meetings of Stockholders" and "—Amendments" may not be repealed or amended in any respect, and no other provision may be adopted, amended or repealed which would have the effect of modifying or permitting the circumvention of the provisions set forth in any such sections, unless such action is approved by the affirmative vote of the holders of not less than a majority of the total voting power of all outstanding securities of the Company generally entitled to vote in the election of directors, voting together as a single class.

Amendment of Bylaws

Our bylaws may be altered, amended or repealed, or new bylaws may be made, by (i) the stockholders entitled to vote thereon at any annual or special meeting thereof or (ii) by the board of directors. Unless a higher percentage is required by the certificate of incorporation, all such amendments must be approved by (i) the affirmative vote of the holders of not less than a majority of the total voting power of all outstanding securities of the Company generally entitled to vote in the election of directors, voting together as a single class, or (ii) by a majority of the board of directors.

Other Limitations on Stockholder Actions

Our bylaws also impose some procedural requirements on stockholders who wish to:

- make nominations in the election of directors;
- propose that a director be removed;
- propose any repeal or change in our bylaws; or
- propose any other business to be brought before an annual or special meeting of stockholders.

Under these procedural requirements, in order to bring a proposal before a meeting of stockholders, a stockholder must deliver timely notice of a proposal pertaining to a proper subject for presentation at the meeting to our corporate secretary along with the following:

- a description of the business or nomination to be brought before the meeting and the reasons for conducting such business at the meeting;

- the stockholder’s name and address;
- any material interest of the stockholder in the proposal;
- the number of shares beneficially owned by the stockholder and evidence of such ownership;
- the principal amount of any indebtedness of the Company or any of its subsidiaries beneficially owned by such stockholder or by any such beneficial owner, together with the title of the instrument under which such indebtedness was issued and a description of any derivative instrument entered into by or on behalf of such stockholder or such beneficial owner relating to the value or payment of any indebtedness of the Company or any such subsidiary; and
- the names and addresses of all persons with whom the stockholder is acting in concert and a description of all arrangements and understandings with those persons, and the number of shares such persons beneficially own.

To be timely, a stockholder must generally deliver notice:

- in connection with an annual meeting of stockholders, not less than 120 nor more than 180 days prior to the date on which the annual meeting of stockholders was held in the immediately preceding year, but in the event that the date of the annual meeting is more than 30 days before or more than 60 days after the anniversary date of the preceding annual meeting of stockholders, a stockholder notice will be timely if received by us not later than the close of business on the later of (1) the 120th day prior to the annual meeting and (2) the 10th day following the day on which we first publicly announce the date of the annual meeting; or
- in connection with the election of a director at a special meeting of stockholders, not less than 40 nor more than 60 days prior to the date of the special meeting, but in the event that less than 55 days’ notice or prior public disclosure of the date of the special meeting of the stockholders is given or made to the stockholders, a stockholder notice will be timely if received by us not later than the close of business on the 10th day following the day on which a notice of the date of the special meeting was mailed to the stockholders or the public disclosure of that date was made.

In order to submit a nomination for our board of directors, a stockholder must also submit any information with respect to the nominee that we would be required to include in a proxy statement, as well as some other information. If a stockholder fails to follow the required procedures, the stockholder’s proposal or nominee will be ineligible and will not be voted on by our stockholders.

Limitation of Liability of Directors and Officers

Our certificate of incorporation provides that no director will be personally liable to us or our stockholders for monetary damages for breach of fiduciary duty as a director, except as required by applicable law, as in effect from time to time. Currently, Delaware law requires that liability be imposed for the following:

- any breach of the director’s duty of loyalty to our company or our stockholders;
- any act or omission not in good faith or which involved intentional misconduct or a knowing violation of law;

- unlawful payments of dividends or unlawful stock repurchases or redemptions as provided in Section 174 of the DGCL; and

- any transaction from which the director derived an improper personal benefit.

As a result, neither we nor our stockholders have the right, through stockholders' derivative suits on our behalf, to recover monetary damages against a director for breach of fiduciary duty as a director, including breaches resulting from grossly negligent behavior, except in the situations described above.

Our bylaws provide that, to the fullest extent permitted by law, we will indemnify any officer or director of our company against all damages, claims and liabilities arising out of the fact that the person is or was our director or officer, or served any other enterprise at our request as a director, officer, employee, agent or fiduciary. We will reimburse the expenses, including attorneys' fees, incurred by a person indemnified by this provision when we receive an undertaking to repay such amounts if it is ultimately determined that the person is not entitled to be indemnified by us. Amending this provision will not reduce our indemnification obligations relating to actions taken before an amendment.

Delaware Business Combination Statute

We are subject to Section 203 of the DGCL, which regulates corporate acquisitions. Section 203 prevents an "interested stockholder," which is defined generally as a person owning 15% or more of a corporation's voting stock, or any affiliate or associate of that person, from engaging in a broad range of "business combinations" with the Company for three years after becoming an interested stockholder unless:

- the board of directors of the Company had previously approved either the business combination or the transaction that resulted in the stockholder's becoming an interested stockholder;

- upon completion of the transaction that resulted in the stockholder's becoming an interested stockholder, that person owned at least 85% of the voting stock of the Company outstanding at the time the transaction commenced, other than statutorily excluded shares; or

- following the transaction in which that person became an interested stockholder, the business combination is approved by the board of directors of the Company and holders of at least two-thirds of the outstanding voting stock not owned by the interested stockholder.

Under Section 203, the restrictions described above also do not apply to specific business combinations proposed by an interested stockholder following the announcement or notification of designated extraordinary transactions involving the Company and a person who had not been an interested stockholder during the previous three years or who became an interested stockholder with the approval of a majority of the Company's directors, if such extraordinary transaction is approved or not opposed by a majority of the directors who were directors prior to any person becoming an interested stockholder during the previous three years or were recommended for election or elected to succeed such directors by a majority of such directors.

Anti-Takeover Effects of Some Provisions

Some provisions of our certificate of incorporation and bylaws could make the following more difficult:

- acquisition of control of us by means of a proxy contest or otherwise, or

- removal of our incumbent officers and directors.

These provisions, as well as our ability to issue preferred stock, are designed to discourage coercive takeover practices and inadequate takeover bids. These provisions are also designed to encourage persons seeking to acquire control of us to first negotiate with our board of directors. We believe that the benefits of increased protection give us the potential ability to negotiate with the proponent of an unfriendly or unsolicited proposal to acquire or restructure us, and that the benefits of this increased protection outweigh the disadvantages of discouraging those proposals, because negotiation of those proposals could result in an improvement of their terms.

Listing

Our common stock is listed on the New York Stock Exchange and on the London Stock Exchange under the symbol “KOS”.

Transfer Agent and Registrar

The transfer agent and registrar for the common stock listed on the New York Stock Exchange is Computershare Trust Company, N.A. The transfer agent and registrar for the common stock listed on the London Stock Exchange is Computershare Investor Services PLC.

Exhibit 10.46
EXECUTION VERSION

***** INDICATES CERTAIN CONFIDENTIAL PORTIONS OF THIS EXHIBIT THAT 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.**

<u>February 11, 2020</u>

LA SOCIETE MAURITANIENNE DES HYDROCARBURES ET DE PATRIMOINE MINIER

and

BP MAURITANIA INVESTMENTS LIMITED

and

KOSMOS ENERGY MAURITANIA

and

LA SOCIETE DES PÉTROLES DU SENEGAL

and

BP SENEGAL INVESTMENTS LIMITED

and

KOSMOS ENERGY INVESTMENTS SENEGAL LIMITED

and

BP GAS MARKETING LIMITED

AGREEMENT FOR A LONG TERM SALE AND PURCHASE OF LNG

from Greater Tortue/Ahmeyim field offshore Mauritania and Senegal

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THIS AGREEMENT, dated this __ day of _____, 2020 is made

BETWEEN:

(1) **LA SOCIETE MAURITANIENNE DES HYDROCARBURES ET DE PATRIMOINE MINIER**, the national oil company of the Islamic Republic of Mauritania, incorporated by Decree No. 2005-106 dated 7 November 2005 as amended by Decree No. 2009-168 dated 3 May 2009 and Decree No. 2014-001 dated 6 January 2014 under the laws of the Islamic Republic of Mauritania and having its registered office at l'Ilot K Rue 42-133, N° 349, BP 4344, Nouakchott, Mauritania ("**SMHPM**");

(2) **BP MAURITANIA INVESTMENTS LIMITED**, a company incorporated under the laws of England and Wales, with company number 10519279, and having its registered office at Chertsey Road, Sunbury On Thames, Middlesex, United Kingdom, TW16 7BP and with a registered branch in Mauritania with registration number 94860/GU/15869 ("**BPMIL**");

(3) **KOSMOS ENERGY MAURITANIA**, a company incorporated under the laws of the Cayman Islands, with company number 266444, and having its registered office at Century Yard, 4th Floor, Cricket Square, P.O. Box 32322, George Town, Grand Cayman KY1, 1209 ("**KEM**");

(4) **LA SOCIETE DES PETROLES DU SENEGAL**, the national oil company of the Republic of Senegal, incorporated under the Laws of the Republic of Senegal, with a share capital of 5,021,000,000 FCFA, registered at the Commercial Register under number RC-SN-DKR-1981-B-82 and modified under number SN-DKR-2013-M-4659, and having its registered office at Route du Service Geographique, Hann BP 2076, Dakar, Senegal ("**PETROSEN**");

(5) **BP SENEGAL INVESTMENTS LIMITED**, a company incorporated under the laws of England and Wales, with registered number 09978028, and having its registered office at Chertsey Road, Sunbury On Thames, Middlesex, United Kingdom, TW16 7BP and with a registered branch in Senegal with registration number SN.DKR.2017.E.16337 ("**BPSIL**");

(6) **KOSMOS ENERGY INVESTMENTS SENEGAL LIMITED**, a company incorporated under the laws of England and Wales, with registered number 10520822, and having its registered office at 6th Floor, 65 Gresham Street, London, United Kingdom, EC2V 7NQ ("**KEISL**");

(SMHPM, BPMIL, KEM, PETROSEN, BPSIL and KEISL each a "**Seller**" and together the "**Seller Group**")

(7) **BP GAS MARKETING LIMITED**, a company incorporated under the laws of England, with registered number 908982, and having its registered office at Chertsey Road, Sunbury-on-Thames, Middlesex TW16 7BP (the "**Buyer**");

RECITALS:

(A) SMHPM, BPMIL and KEM are parties to an exploration and production contract covering the Block C8 Contract Area offshore Mauritania signed on 5 April 2012 and effective 15 June 2012;

(B) PETROSEN, BPSIL and KEISL are parties to a hydrocarbon exploration and production contract covering the Saint-Louis Offshore Profond Block Contract Area offshore Senegal signed on 17 January 2012 and effective 19 June 2012;

(C) The Greater Tortue/Ahmeyim field encompasses a portion of the contract areas of both the Block C8 PSC and the St-Louis PSC. Pursuant to the authority of the Inter-State Cooperation Agreement (ICA) entered into by Mauritania and Senegal on 9 February 2018, SMHPM, BPMIL, KEM, PETROSEN, BPSIL and KEISL entered into a Unitization and Unit Operating Agreement dated 7 February 2019 for the Greater Tortue/Ahmeyim field. The Seller Group are currently engaged in the development of the Greater Tortue/Ahmeyim field utilising a FLNG facility from which LNG is to be produced;

(D) The Seller Group wishes to make available and sell and deliver to the Buyer quantities of LNG at the Delivery Point, in accordance with the terms of this Agreement;

(E) The Buyer wishes to purchase and receive from the Seller Group quantities of LNG at the Delivery Point, in accordance with the terms of this Agreement;

(F) The Buyer intends to deliver a programme of capability development and training to SMHPM and PETROSEN for the duration of this Agreement to support national talent development in accordance with Schedule 6.

NOW THEREFORE, in consideration of the mutual agreements contained herein, **it is hereby agreed** as follows:

1. DEFINITIONS AND INTERPRETATION

1.1 Definitions

In this Agreement, except to the extent that the context requires otherwise:

"ABC Law" means any anti-bribery, corruption or anti-money laundering Law which applies to any Party in relation to the subject matter of this Agreement, including applicable anti-corruption Laws of Mauritania and Senegal, the United States of America's Foreign Corrupt Practices Act, the UK Bribery Act 2010, the OECD Convention on Combating Bribery of Foreign Public Officials in International Business Transactions, signed in Paris on December 17, 1997, which entered into force on February 15, 1999, and the Convention's Commentaries, and any other Laws or regulations in any jurisdiction relating to bribery, corruption or any similar practices to the extent applicable to a Party (as the case may be).

"ABC Law Violation" means a situation where any Party (or any of that Party's Representatives) has breached any ABC Law with respect to or in connection with the subject matter of this Agreement or any activities contemplated hereunder.

Acceptable Affiliate" means:

(i)[***] provided that at all times when acting as an Acceptable Credit Support Provider, it: (A) has net assets (being total assets less total liabilities, as shown in the balance sheet of its latest audited financial statements) of not less than [***] and (B) is, directly or indirectly, a Wholly Owned Affiliate of the ultimate parent or ultimate holding company of the Buyer; or

(ii) if at any time [***] does not meet the requirements of paragraph (i) above, any other Affiliate of the Buyer provided that, at all times when acting as an Acceptable Credit Support Provider, it: (A) has net assets (being total assets less total liabilities as shown in the balance sheet of its latest audited financial statements) of not less than [***] and (B) is itself, or is, directly or indirectly, a Wholly Owned Affiliate of the ultimate parent or ultimate holding company of the Buyer.

Acceptable Credit Support" means:

(i) a Deed of Guarantee issued by [***]; or

(ii) if at any time [***] is no longer an Acceptable Affiliate:

(A) a Deed of Guarantee issued by an Acceptable Affiliate;

(B) a Bank Guarantee issued by an Acceptable Financial Institution; or

(C) a Letter of Credit issued by an Acceptable Financial Institution,

"Acceptable Credit Support Provider" means an entity which is either

(i) an Acceptable Affiliate; or

(ii) an Acceptable Financial Institution.

“**Acceptable Financial Institution**” means any top tier international bank or financial institution based in the United States, France, Switzerland or the United Kingdom which has a long-term credit rating of not lower than [***] from Standard & Poor’s Ratings Services or not lower than [***] from Moody’s Investors Service Inc., or, if both such agencies cease to publish credit ratings or the definitions of such ratings change in any material respect during the Contract Term or the relevant agency ceases, for any reason, to be generally recognised in the interbank market as a reliable source of long-term credit ratings, an equivalent rating from another agency of similar repute reasonably acceptable to the Seller Group.

"Adjusted ACQ" or **"AACQ"** is as defined in Clause 7.2.

“ADP/SDS Change Notice” is as defined in Clause 10.5.1.

"Adverse Weather" means weather, sea or metocean conditions actually experienced or forecast to be experienced, at or near the LNG Hub Facilities that are sufficiently severe:

(i) to delay or prevent an Approved LNG Ship from proceeding to berth, loading and/or departing from berth at the LNG Hub Facilities in accordance with the weather standards prescribed in the Facilities Manuals or by order of the LNG Hub Facilities Operator; and/or

(ii) to cause an actual determination by the master of the Approved LNG Ship that it is unsafe to berth, load or depart from berth.

"Affected Party" is as defined in Clause 16.5.

"Affiliate" means a legal entity which Controls, or is Controlled by, or which is Controlled by an entity which Controls, a Person, except that:

(i) neither the Buyer nor any subsidiary under the Buyer's Control shall be considered an Affiliate of BPMIL or BPSIL;

(ii) neither BPMIL, BPSIL nor any subsidiary under the Control of BPMIL or BPSIL shall be considered an Affiliate of the Buyer; and

(iii) except with respect to Clause 3.1.4, 5.3.1, 16.1.5 and Clause 24, no Competent Authority in the Islamic Republic of Mauritania shall be considered an Affiliate of SMHPM (or any Mauritania State-owned successor Party) and no Competent Authority in the Republic of Senegal shall be considered an Affiliate of PETROSEN (or any Senegal State-owned successor Party).

[***]

"Agreement" means this Agreement.

"Allowed Laytime" is as defined in Clause 9.12.2.

[***]

"Annual Contract Quantity" or **"ACQ"** means the quantity of LNG specified in Clause 7.1.1.

"Annual Deliver or Pay Obligation" is as defined in Clause 10.1.13.

"Annual Deliver or Pay Price" is as defined in Clause 10.1.14.

"Annual Deliver or Pay Quantity" is as defined in Clause 10.1.13.

"Annual Delivery Programme" or **"ADP"** means the programme for loading LNG for any Contract Year, as defined in Clause 10.1.1 and including any Extension Period Annual Delivery Programme pursuant to Clause 10.3, as appropriate.

"Annual Take or Pay Obligation" is as defined in Clause 10.1.11.

"Annual Take or Pay Price" is as defined in Clause 10.1.12.

"Annual Take or Pay Quantity" is as defined in Clause 10.1.11.

"Approved LNG Ship Conditions" is as defined in Clause 9.3.2.

"Approved LNG Ship" means an LNG vessel listed in Schedule 2 and any LNG vessel which meets the Approved LNG Ship Conditions, is nominated by the Buyer and is approved by the Seller Group pursuant to Clause 9.3 to be used by the Buyer for the receipt and transportation of LNG under this Agreement. Schedule 2 shall be amended from time to time to list the Approved LNG Ships.

"Approved 125 LNG Ship" means an Approved LNG Ship with a gross volumetric capacity of approximately one hundred and twenty-five thousand (125,000) cubic metres.

"Approved 155 LNG Ship" means an Approved LNG Ship with a gross volumetric capacity of approximately one hundred and fifty-five thousand (155,000) cubic metres.

"Approved 174 LNG Ship" means an Approved LNG Ship with a gross volumetric capacity of approximately one hundred and seventy-four thousand (174,000) cubic metres.

"Arrival Window" means:

(i) in relation to a Commissioning Cargo, the twenty four (24) hour period commencing at 00:01 hours (local time at the Loading Terminal) notified to the Buyer by the Seller Group's Representative in accordance with Clause 5.3.4; or

(ii) in relation to a Cargo, the twenty-four (24) hour period commencing at 00:01 hours (local time at the Loading Terminal) notified in the relevant Annual Delivery Programme or Specific Delivery Schedule (whichever is more recent);

during which period the Approved LNG Ship is scheduled to arrive at the Pilot Boarding Station of the LNG Hub Facilities and tender NOR.

"Arrival Temperature" is as defined in Clause 9.10.

"ASTM" means ASTM International formerly known as the American Society for Testing and Materials.

"Authorisation" means an authorisation, consent, approval, permit, ruling, resolution, licence, concession, exemption, filing, registration or other authorisation or permission or waiver of whatsoever nature that is required to be obtained from and/or granted by any Competent Authority.

"Bank Guarantee" means any one or more irrevocable and unconditional bank guarantees to be provided by the Buyer, which are, when taken together with other Acceptable Credit Support equal to the Buyer Credit Support Amount, less any amount drawn down or demanded (subject to collection of the amount demanded) under Acceptable Credit Support before the date of issuance of the Bank Guarantee, as issued by Acceptable Financial Institutions and naming the Sellers as the beneficiary and which, is in a form acceptable to the Sellers (acting reasonably);

"Base Contract Price" is as defined in Clause 11.1.

"Block C-8 Owners" means the parties who hold a participating interest in the Block C-8 PSC from time to time, being SMHPM, BPMIL and KEM at the date of this Agreement.

"Block C-8 PSC" means the exploration and production contract covering the Block C-8 Contract Area offshore Mauritania dated 5 April 2012 and effective on 15 June 2012 to which SMHPM, BPMIL and KEM are parties at the date of this Agreement.

[***]

"Btu", **"BTU"** or **"British Thermal Unit"** means the amount of heat equal to one thousand and fifty-five decimal zero five six (1,055.056) Joules.

"Business Day" means any day, other than a Saturday, Sunday or any other day on which commercial banks in London (UK), New York (United States of America), Paris (France), Geneva (Switzerland) Nouakchott, Mauritania, Dakar, Senegal, the location of a Seller's Account, or the State's Accounts or the location of the Buyer's Account are closed for business.

"**Buyer Credit Support Amount**" means [***] Dollars to provide security for:

[***]

"Buyer Event of Default" is as defined in Clause 22.1.

"Buyer Insolvency Event" means an Insolvency Event occurring in respect of the Buyer.

"Buyer Tracking Account Entitlement" is as defined in 7.1.2(F).

"Buyer's Account" means a bank account, designated by the Buyer in accordance with Clause 12.3.5.

"Buyer's Consents" means, at any time, any and all Authorisations that are required at that time to allow the Buyer or its Affiliates, as the context may require, to perform its obligations under this Agreement.

"Buyer's Force Majeure" is as defined in Clause 16.2.

"Calendar Quarter" means, in any year, each of the following periods (all dates inclusive):

(i)1 January to 31 March;

(ii)1 April to 30 June;

(iii)1 July to 30 September; and

(iv)1 October to 31 December.

"Cargo" means the aggregate quantity of LNG scheduled to be loaded onto an Approved LNG Ship whether in one or multiple berthings and shall include any Commissioning Cargo.

"Cargo Deliver or Pay Credit" is as defined in Clause 7.6.3.

"Cargo Deliver or Pay Obligation" is as defined in Clause 7.6.1.

"Cargo Deliver or Pay Price" is as defined in Clause 7.6.1.

"Cargo Deliver or Pay Quantity" is as defined in Clause 7.6.1.

[***]

"Cargo Take or Pay Obligation" is as defined in Clause 7.4.1.

"Cargo Take or Pay Price" is as defined in Clause 7.4.1.

"Cargo Take or Pay Quantity" is as defined in Clause 7.4.1.

"Commercial Operations Date" is as defined in Clause 5.2.2.

"Commissioning Cargo" is as defined in Clause 5.3.1.

"Commissioning Cargo Quantity" is as defined in Clause 5.3.4(D).

"Commissioning Period" is as defined in Clause 5.1.

"Commissioning Period Price" is as defined in Clause 11.2.

"Commissioning Start Date" means the first day of the Commissioning Period, as determined in accordance with Clause 5.1, being the date on which the Seller Group has completed any necessary commissioning of the Upstream Facilities and the Upstream Facilities are ready to allow the FLNG Facility to start the commissioning and testing process as established under the FLNG Lease and Operate Agreement.

"Competent Authority" means any national, regional, state, municipal or other local government, or any subdivision, agency, trust, department, regulator, commission, inspectorate, minister, ministry, official, public or statutory Person (whether autonomous or not), quasi-governmental organisation or authority, including any port authority, any court, tribunal, judicial or quasi-judicial authority or other Person exercising executive, legislative, judicial, regulatory or administrative functions of any of the foregoing, in each case, acting or purporting to act within its legal authority.

"Completion of Loading" means, following loading of a Cargo on the relevant Approved LNG Ship, the time at which:

(i) all the flange couplings of her cargo manifold have been disconnected from the flange couplings of the loading lines at the LNG Hub Facilities;

(ii) the flange coupling of her vapour return line has been disconnected from the flange coupling of the vapour receipt line at the LNG Hub Facilities; and

(iii) all relevant documents required for the Approved LNG Ship to leave the LNG Hub Facilities and proceed to open sea have been received by the master of the Approved LNG Ship, excluding any documents to be provided by the Buyer, the master of the Approved LNG Ship or the Independent Surveyor.

"Conditions of Use" or **"COU"** means the required conditions for the use by any Approved LNG Ship of the LNG Hub Facilities that relate to safety, prevention and remediation of pollution, insurance, liability, public health, required equipment and its technical specifications and/or similar financial, technical or operational requirements, which shall initially be as attached hereto as Schedule 8, as may be updated from time to time in accordance with Clause 9.2.6.

“Conditions of Use Requirements” is as defined in Clause 9.2.5.

"Consequential Loss" is as defined in Clause 17.1.

"Contract Price" means the Base Contract Price or Commissioning Period Price [***] applicable to a Cargo pursuant to Clause 11.

"Contract Term" means the Initial Term and the First Extension Term (if applicable) and the Second Extension Term (if applicable).

"Contract Year" means each successive period of twelve (12) consecutive months during the Contract Term starting on the day of 1 January and ending on the next following 31 December, provided that:

(i) the first Contract Year shall commence on the Commercial Operations Date and end on the next following 31 December; and

(ii) the final Contract Year shall end on the expiration of the last day of the Contract Term.

"Control" means:

(a) in respect of the Block C-8 Owners, the ownership directly or indirectly of more than fifty percent (50%) of the voting rights in a company or any other legal entity;

(b) in respect of the St-Louis Owners, the ownership directly or indirectly of at least fifty percent (50%) of the voting rights in a company or any other legal entity; and

(c) in respect of any other Persons, the ownership of fifty percent (50%) or more of the voting rights in a company or any other legal entity,

and "**Controls**", "**Controlled by**" and other derivatives shall be construed accordingly.

“**Credit Support Provider**” means any Person issuing a Deed of Guarantee, a Bank Guarantee or a Letter of Credit;

"Daily Boil-off Rate" means, for each Approved LNG Ship, the amount set out as a percentage per day in Schedule 2 for such Approved LNG Ship, and for any Proposed LNG Ship that becomes an Approved LNG Ship, the percentage per day set out in Form B or C, or in the OCIMF Harmonized Vessel Particulars Questionnaire (as applicable), reflecting the design specifications for such vessel, [***].

“**Deed of Adherence**” is as defined in Clause 3.1.4.

“**Deed of Guarantee**” means an irrevocable and unconditional deed of guarantee for the Buyer Credit Support Amount, less any amount drawn down or demanded (subject to collection of the amount demanded) under Acceptable Credit Support before the date of issuance of a Deed of Guarantee, from:

(i) [***]; or

(ii) if at any time [***] is not an Acceptable Affiliate, any other Acceptable Affiliate of the Buyer,

and naming the Sellers as the beneficiaries, substantially on the form set out in Schedule 5.

“**Deed of Novation**” is as defined in Clause 3.1.4.

"Defaulting Party" is as defined in Clause 22.6.1.

"Delivery Point" is as defined in Clause 8.1.

“Deliverability Report” means a report delivered in conjunction with a Reserves Report or Reserves Certificate reflecting the quantities and rates at which Natural Gas supplies can be delivered from the Gas Supply Area to the FLNG Facility and Future GTA Project if applicable during the Contract Term, prepared by an independent engineer.

“**Deliverability**” means the rate at which Natural Gas can be produced from the Gas Supply Area;

"Demurrage" means the amount payable at the Demurrage Rate by the Seller Group to the Buyer in the circumstances set out in Clause 9.12.5.

“**Demurrage Rate**” means, for each Approved LNG Ship [***].

"Directive" means any present or future requirement, instruction, direction, rule or requirement of any Competent Authority that is legally binding and any modification, extension or replacement thereof from time to time in force.

"Dispute" is as defined in Clause 23.2.1.

[***]

"Dollar", **"USD"** and **"$"** means the lawful currency of the United States of America.

“Due Diligence Requests” is as defined in Clause 3.1.3.

[***]

"Effective Date" is as defined in Clause 4.1.

“**Escrow Account**” means an escrow account with an Acceptable Financial Institution established in accordance with the Escrow Arrangements.

“**Escrow Arrangements**” means the escrow arrangements to be agreed by the Buyer and the Seller Group (each acting reasonably) no later than the date that is ninety (90) days after the issuance of any Bank Guarantee or Letter of Credit provided by or on behalf of the Buyer pursuant to Clause 12 or, if applicable. implemented by the beneficiaries pursuant to Clause 12.7.7, providing for (among other things) the deposit to the Escrow Account of amounts drawn on any Bank Guarantee or Letter of Credit, the release of those amounts to the named beneficiary of the relevant Bank Guarantee or Letter of Credit in circumstances in which such Bank Guarantee or Letter of Credit can be drawn upon by such named beneficiary and the return of amounts standing to the credit of the Escrow Account to the Buyer or the Seller Group (as applicable) upon replacement Acceptable Credit Support being provided by or on behalf of the Buyer or the Seller Group in accordance with this Agreement.

"Estimated Time of Arrival" or **"ETA"** is as defined in Clause 9.7.1.

"Expert" means an appropriately qualified and experienced professional who is knowledgeable in the international LNG industry and is technically competent in the subject area of any Dispute and who is appointed pursuant to Clause 23.3.1.

"Export" means the shipment of LNG sold under this Agreement from the customs territory of Mauritania and/or Senegal, to a destination outside the customs territory of Senegal and/or Mauritania.

"Exporter of Record" means the entity responsible for obtaining and documenting Export clearance.

"Extension Period" means a period after the Initial Term during which this Agreement is extended pursuant to Clause 6.2, being the First Extension Period or the Second Extension Period.

"Facilities Manuals" means the operations manual and marine operations manual to be produced in respect of the LNG Hub Facilities and the FLNG Facility and which shall include the implementation procedures for the services to be provided by the LNG Hub Facilities Operator and the FLNG Facility Operator and the procedures applicable to the Approved LNG Ships.

"Feed Gas" means processed Natural Gas delivered to the FLNG Facility and/or Future Facilities for the production of LNG.

“Firm LNG Buyer” any LNG purchaser (excluding Buyer) under an agreement wherein such LNG buyer undertakes to take or pay for, and the Seller undertakes to deliver, LNG on a firm basis from the Seller Group’s Facilities.

"First Extension Term" is as defined in Clause 6.2.1(A).

“First Loading” is as defined in Clause 7.4.1.

"First Window Period" is as defined in Clause 5.1.2.

"FLNG Facility" means a Moss-type floating liquefaction vessel (containing LNG storage facilities) to be moored at the LNG Hub Facilities, provided under the terms of the FLNG Lease and Operate Agreement.

"FLNG Facility Operator" means Golar MS Operator S.A.R.L., incorporated in Mauritania, the operator of the FLNG Facility, being a wholly owned subsidiary of Gimi MS Corporation, or any successor operator of the FLNG Facility.

"FLNG Lease and Operate Agreement" or **“LOA”** means that certain Lease and Operate Agreement by and between Gimi MS Corporation and BPMIL, as operator under the UUOA, dated 26 February 2019, for the provision of the FLNG Facility.

"FLNG Provider" means Gimi MS Corporation.

"Force Majeure Event" means Buyer's Force Majeure or Seller's Force Majeure.

“FM Notice” is as defined in Clause 16.5.

“Future Facilities Commercial Operations Date” means the date, on which the commissioning and testing process in respect of the Future Facilities is completed, which shall be notified by the Seller Group to the Buyer.

"Future Facilities Commissioning Start Date" means the date on which the Future Facilities are ready to start the commissioning and testing process.

"Future Facilities" means any and all variations and modifications to the existing Upstream Facilities and/or the existing LNG Hub Facilities, as well as any new facilities, including additional upstream facilities, additional LNG hub facilities, an additional FLNG facility, additional liquefaction facilities and additional LNG storage facilities, required for the purpose of implementing the Future GTA Project.

"Future Facilities Implementation Works" means any planning, development, design, engineering, procurement, manufacturing, financing, construction, fabrication, erection, permitting, completion, testing, commissioning, installation, insurance, ownership, classification, operation and maintenance work in respect of the Future Facilities, for the purpose of implementing the Future GTA Project.

"Future GTA Project" means the development, design, engineering, procurement, manufacturing, financing, construction, fabrication, erection, permitting, completion, testing, commissioning, installation, insurance, ownership, classification, operation and maintenance of an LNG export project for the phases of development of the Gas Supply Area subsequent to the first phase.

"Gas Supply Area" means the Greater Tortue/Ahmeyim gas field, underlying the unit area established by the UUOA, from which Natural Gas is produced, as described more fully in Part A of Schedule 1.

"GIIGNL" means the International Group of Liquefied Natural Gas Importers.

"GPA" means the Gas Processors Association.

"Gross Heating Value (Mass)" means, when expressed in MJ/kg the quantity of heat produced by the complete combustion in dry air of one (1) kilogram mass of dry ideal gas and the condensation of all the water formed, with the initial and final temperature and pressure being fifteen (15) degrees Celsius and one hundred and one decimal three two five (101.325) kilopascals absolute respectively.

"Gross Heating Value (Volumetric)" means when expressed in Btu/SCF, the quantity of heat produced by the complete combustion in dry air of one (1) Standard Cubic Foot of dry ideal gas and the condensation of all the water formed with the initial and final temperature and pressure being sixty (60) degrees Fahrenheit and fourteen decimal six nine six (14.696) pounds per square inch respectively.

"GTA Project" means the development, design, engineering, procurement, manufacturing, financing, construction, fabrication, erection, permitting, completion, testing, commissioning, installation, insurance, ownership, classification, operation and maintenance of an LNG export project for the first phase of development of the Gas Supply Area including the Upstream Facilities and the FLNG Facility.

"GTT" means Gaz Transport and Technigaz, an LNG cargo tank engineering company whose details are available at https://www.gtt.fr/.

"HSSE" means health, safety, security and environment.

"IACS" is as defined in Clause 9.3.13(C).

"ICA" means the Inter-state Cooperation Agreement dated 9 February 2018 between the States pertaining to the unitization, development and exploitation of the Gas Supply Area and liquefaction and marketing of LNG produced from the Gas Supply Area.

"In Year Surplus Quantity" is as defined in Clause 7.3.3.

"**Independent Engineer**" means an internationally recognised independent petroleum engineering firm selected by the Seller Group.

"Independent Surveyor" means the independent surveyor agreed upon by the Buyer and the Seller Group pursuant to Schedule 3.

"Initial Term" is as defined in Clause 6.1.

"Insolvency Event" means in respect of a Person, the occurrence of any of the following:

(a) it is dissolved (other than pursuant to a permitted consolidation, amalgamation or merger);

(b) it becomes insolvent or is unable to pay its debts or fails or admits in writing its inability generally to pay its debts as they become due;

(c) it suspends making payments on indebtedness (or any category of indebtedness);

(d) by reason of actual or anticipated financial difficulties, it commences negotiations with its creditors generally, with a view to rescheduling any of its indebtedness;

(e) a secured party takes possession of all or substantially all its assets or has a distress, execution, attachment, sequestration or other legal process levied, enforced or sued on or against all or substantially all its assets and such secured party maintains possession, or any such process is not dismissed, discharged, stayed or restrained, in each case within fifteen (15) days thereafter;

(f) any corporate action, legal proceedings or other procedure or step is taken in relation to:

i. the suspension of payments (or any category of payments) generally, a moratorium of any indebtedness (or any category of indebtedness) generally, Winding-Up, dissolution, administration or reorganisation of that Person or an administrator is appointed for that Person;

ii. a composition, compromise, assignment or arrangement with that Person's creditors generally;

iii. seeking or becoming subject to the appointment of a liquidator, receiver, administrative receiver, administrator, compulsory manager or other similar officer in respect of the Person or any of its assets; or

iv. any analogous procedure or step is taken in any jurisdiction;

v. provided that this Clause (v.) does not apply to any Winding-Up petition which is frivolous or vexatious and is discharged, stayed or dismissed within seventy-five (75) days of commencement.

"Interest Rate" means interest calculated at the rate of LIBOR, calculated on the basis of a [***] day year. If LIBOR is not published on the first day of the relevant period, then the LIBOR published on the nearest preceding day shall be used.

"International Standards" means the international standards, practices and guidelines from time to time applicable to the ownership, design, construction, equipment, operation or maintenance of LNG production facilities (floating or otherwise), LNG loading terminals and LNG ships, and the measurement, testing and analysis of LNG established by the OCIMF, SIGTTO ASTM, ISO, GPA and GIIGNL (or successor body of any of the same or any other internationally recognised agency or organisation), with which standards, practices and guidelines it is customary for Reasonable and Prudent Operators of such facilities and LNG ships to comply.

“Inventory Conflict” means an event where the aggregate quantity of LNG, in cubic meters, in the LNG storage tanks at the FLNG Facility either (i) exceeds or is reasonably expected to exceed the Maximum Inventory Level or (ii) fails or is reasonably expected to fail to remain above the Minimum Inventory Level.

“Inventory Level” means the LNG inventory level in the tanks in the FLNG Facility.

"ISO" means the International Organization for Standardization.

"Joule" has the meaning shown in ISO 80000-1.

"Kilogram" or **"kg"** has the meaning shown in ISO 1000:1992(E).

"Law" means all common or customary law for the time being or as amended, including any and all statutes, laws, legislation, regulations, ordinances, orders, decrees, judgments, rules, codes, Directives, treaties, consents, notes, decisions and any other legislative measures, in each case of any jurisdiction whatsoever having the force of law (and **"lawful"** and **"unlawful"** shall be construed accordingly).

“Letter of Credit” means any one or more irrevocable and unconditional standby letters of credit to be provided by the Buyer, which are, when taken together with other Acceptable Credit Support equal to the Buyer Credit Support Amount, less any amount drawn down or demanded (subject to collection of the amount demanded) under Acceptable Credit Support before the date of issuance of the Letter of Credit, as issued by Acceptable Financial Institutions and naming the Sellers as the beneficiaries; and which, is in a form acceptable to the Sellers (acting reasonably).

"LIBOR" means the applicable Screen Rate; as of 11:00 am on the Reference Day for three (3) month deposits of Dollars and, if any such applicable Screen Rate is below zero (0), LIBOR will be deemed to be zero (0). If LIBOR ceases to be published for any reason (other than temporarily) or ceases to exist or there is a fundamental change in the manner in which any such index or rate is calculated, a replacement index or rate will be determined in accordance with Clause 11.4.If the Screen Rate is not available for the relevant period, the Parties shall apply such comparable rate as the Parties may agree.

"LNG" means Natural Gas in a liquid state at or below its point of boiling and at or near atmospheric pressure.

"LNG Hub Facilities" means the shallow water breakwater, incorporating marine structures (trestles/jetty, berths, moorings, docks), jetty topsides (gas receiving, LNG transfer lines and offloading arms, utilities distribution) and living quarters/utilities facilities located at Latitude: 16°04’00”N, Longitude 16°36’00”W (WGS84) as shown on the map attached as Part B in Schedule 1, and all vessels, equipment and facilities required to carry out the Marine Services, but shall not include the FLNG Facility.

"LNG Hub Facilities Operator" means the operator of the LNG Hub Facilities, being the "Unit Operator" appointed pursuant to the UUOA.

"LNG Ship International Conventions, Rules and Regulations" is as defined in Clause 9.3.11(C).

"LNG SPA Participation" means each Seller's undivided share (expressed as a percentage of the total shares of all of the Seller Group) in the rights, interests, obligations and liabilities of the Seller Group under this Agreement, as set out in Clause 3.1.1 and as such LNG SPA Participations may be amended and notified pursuant to Clauses 3.1.2 and 3.1.5.

"LOA Commercial Operations Date" means the "Commercial Operations Date" as defined in and under the FLNG Lease and Operate Agreement, being the date on which the FLNG Facility passes all relevant acceptance tests or is otherwise accepted by the operator (as designated under the UUOA) pursuant to the LOA.

"Loading Terminal" means the loading facility at the LNG Hub Facilities or any other loading terminal at which LNG is, or is proposed to be, made available under this Agreement.

"Make-Up Quantity" is as defined in Clause 7.5.1.

"Marine Authorisations" is as defined in Clause 9.6.2.

"Marine Services" means all services necessary for the safe approach, berthing, mooring, loading, unberthing and departure of an Approved LNG Ship at the LNG Hub Facilities, including towing, escort, fireboats, line handling, pilot services, harbour/assist tugs and boats required by an Approved LNG Ship (such approach and departure being from and to the Pilot Boarding Station).

"Marine Working Group" means the forum established by Buyer and the Seller Group, for the exchange of required technical, operational and safety information to support effective and safe marine interfaces contemplated under this Agreement, as provided for in Schedule 7.

"Mauritania State Share" is as defined in Clause 3.1.1(B).

"Maximum Inventory Level" means [***] in the FLNG Facility.

"Megajoule" or **"MJ"** means one million (1,000,000) Joules.

"Minimum Inventory Level" means [***] in the FLNG Facility.

"MMBtu" means one million (1,000,000) Btu.

"Natural Gas" means any hydrocarbon or mixture of hydrocarbons consisting predominantly of methane, which may contain other hydrocarbons and non-combustible gases, all of which are substantially in the gaseous phase at atmospheric temperature and pressure.

[***]

"Non-Affected Party" is as defined in Clause 16.5.

"Non-Defaulting Party" is as defined in Clause 22.6.1.

"Notice of Dispute" is as defined in Clause 23.1.1.

"Notice of Readiness" or **"NOR"** is as defined in Clause 9.8.

"Normal Cubic Metre" or **"Nm^3"** means, in relation to gas, the quantity of dry ideal gas, at a temperature of zero (0) degrees Celsius and a pressure of one hundred and one decimal three two five (101.325) kilopascals absolute contained in a volume of one (1) cubic metre;

"Off-Specification LNG" is as defined in Clause 14.2.1.

"Offered In Year Surplus Quantity" is as defined in Clause 7.3.1.

"OCIMF" means the Oil Companies' International Marine Forum.

"Operational Tolerance" is as defined in Clause 7.9.

"Party" means a party to this Agreement and includes its successors in title, permitted assigns and permitted transferees.

“Payee” is as defined in Clause 13.3.

“Payer” is as defined in Clause 13.3.

“Permitted Time” means:

(i) for Commissioning Cargoes, other than the first Commissioning Cargo [***]; and

(ii) for the first Commissioning Cargo [***]; and

(iii) from the Commercial Operations Date until the Future Facilities Commercial Operations Date, a period [***]; and

(iv) after the Future Facilities Commercial Operations Date, a period equal to the Allowed Laytime (without any extension pursuant to Clause 9.12.2),

measured in each case from the time the relevant NOR becomes effective.

“**Person**” has the meaning given in Clause 1.2.17.

"Pilot Boarding Station" means the pilot boarding station or other customary waiting area or the area where the pilot boards the Approved LNG Ship as determined by the relevant Competent Authority or the LNG Hub Facilities Operator.

"Port Charges" means any:

(i) charges, duties, fees, levies, light dues or other marine charges or dues of any sort imposed by any Competent Authority of either of the States, or the LNG Hub Facilities Operator that become payable in connection with the use of the LNG Hub Facilities by an Approved LNG Ship; and

(ii) costs associated with the use of Marine Services.

“Price Adjustment Objectives” is as defined in Clause 11.6.3.

“PRMS” means the *Petroleum Resource Management System* approved by the Society of Petroleum Engineers and the World Petroleum Council in March 2007.

“Proposed Annual Delivery Programme” is as defined in Clause 10.1.4.

"Proposed LNG Ship" is as defined in Clause 9.3.4.

“**Proved Reserves**” and “**Probable Reserves**” is as each term is in the PRMS.

“**Provisional Adjusted Annual Contract Quantity”** or **“PAACQ”** is as defined in Clause 10.1.3.

"Quantity Delivered" means the quantity of LNG (expressed in MMBtu) actually loaded onto an Approved LNG Ship as determined in accordance with Schedule 3.

"Quarterly Statement" is as defined in Clause 7.8.1.

"Reasonable and Prudent Operator" means a Person seeking in good faith to perform its contractual obligations, and in so doing, and in the general conduct of its undertaking, exercising that degree of skill, diligence, prudence and foresight that would reasonably and ordinarily be expected from a skilled and experienced operator complying with all applicable Laws, International Standards, and Authorisations, engaged in the same type of undertaking under the same or similar circumstances and conditions.

"Reference Day" means, in relation to any period for which an interest rate is to be determined, the first day of that period.

"Representatives" means in respect of any Party, that Person and its Affiliates and any Person acting on its or their behalf, including directors, officers, employees and agents, either in private business dealings or in dealings with the public or government sector, directly or indirectly.

“Reserves” means the Proved Reserves and Probable Reserves of Natural Gas in the Gas Supply Area.

“Reserves Certificate” means a certificate provided by an Independent Engineer expressing its estimate of the Reserves available within the Gas Supply Area at the time of such certificate.

“**Reserves Evaluation**” means the process carried out by the Independent Engineer whereby the Proved Natural Gas Reserves and the Probable Natural Gas Reserves are reviewed and estimated in accordance with the PRMS.

“Reserves Report” means a report provided by an Independent Engineer with respect to the results of a Reserves Evaluation and based on the information from such Reserves Evaluation, showing the Proved Reserves and Probable Reserves, such Certified Reserves Report being prepared by an Independent Engineer.

"Round-Down Quantity" is as defined in Clause 7.1.4(C).

"Round-Up Quantity" is as defined in Clause 7.1.4(A).

"Sanctions Authority" means:

(i)the United Nations;

(ii)the United States government;

(iii)the European Union;

(iv)the UK government (including the Privy Council);

(v)the government of the Islamic Republic of Mauritania;

(vi)the government of the Republic of Senegal; or

(vii)the respective governmental institutions and agencies of any of the foregoing,

including without limitation, the Office of Foreign Assets Control of the US Department of Treasury (**"OFAC"**), the United Nations Security Council and Her Majesty's Treasury of the United Kingdom.

"Sanctions List" means the Specially Designated Nationals and Blocked Persons list maintained by OFAC, the Denied Persons List maintained by the US Department of Commerce, the Consolidated List of Financial Sanctions Targets maintained by Her Majesty's Treasury, the European Union’s consolidated list of persons, groups and entities subject to EU financial sanctions, or any other list issued or maintained by any Sanctions Authority of persons subject to Trade Sanctions (including investment or related restrictions), each as amended, supplemented or substituted from time to time.

"Scheduled Downtime" is as defined in Clause 7.1.3(A).

"Scheduled Downtime Quantity" is as defined in Clause 7.1.3(B).

[***]

"Scheduled Loading Quantity" means the quantity of LNG (expressed in MMBtu) expected to be loaded for a Cargo scheduled for delivery in an Annual Delivery Programme and/or Specific Delivery Schedule or scheduled for delivery as a Commissioning Cargo, as stated therein.

"Scheduling Requirements" is as defined in Clause 10.1.1.

"Screen Rate" means the London interbank offered rate administered by Intercontinental Exchange Benchmark Administration Ltd. (or any other Person that takes over the administration of that rate) for the relevant currency for the relevant period displayed on pages LIBOR01 or LIBOR02 of the Reuters screen (or any replacement Reuters page that displays such rate) or on the appropriate page of such other information service that publishes such rate from time to time in place of Reuters.

"Second Extension Term" is as defined in Clause 6.2.1(B).

“Second Loading” is as defined in Clause 7.4.1.

"Second Window Period" is as defined in Clause 5.1.3.

"Seller's Account" means one or more bank accounts, designated by each of the Sellers in accordance with Clause 12.3.4.

"Seller Event of Default" is as defined in Clause 22.3.

"Seller's Force Majeure" is as defined in Clause 16.1.

"Seller Group Event of Default" is as defined in Clause 22.2.

"Seller Group's Annual LNG Production Forecast" is as defined in Clause 10.1.3(H).

"Seller Group's Consents" means, at any time, any and all Authorisations that are required at that time to allow any Seller or its Affiliates, as the context may require, to perform its obligations under this Agreement.

[***]

"Seller Group's Facilities" means the FLNG Facility, the LNG Hub Facilities, the Loading Terminal and any Future Facilities.

"Seller Group Supply Obligation" means, at any point in time, the amount of (i) Natural Gas from the Gas Supply Area, and (ii) LNG produced from Natural Gas produced from the Gas Supply Area required to satisfy the obligations of:

(i) the Seller Group to supply Natural Gas to any Person from the Gas Supply Area during the then-current Contract Year and all subsequent Contract Years under any Natural Gas supply agreements;

(ii) the Seller Group to supply to the Buyer the AACQ and In Year Surplus Quantities for the then-current Contract Year and the ACQ for all subsequent Contract Years; and

(iii) any Seller to supply to any Firm LNG Buyer from the Gas Supply Area the applicable firm contract quantities of LNG for the then-current contract year and all subsequent contract years under sale and purchase agreements with all such buyers;

"Seller Group's Representative" means the Person appointed by the Seller Group in accordance with Clause 3.3 and any successor appointed in accordance with Clause 3.3 [***] to the .5.

"Seller Group's Surplus Notification" is as defined in Clause 7.3.1.

"Seller Insolvency Event" means an Insolvency Event occurring in respect of any Seller.

[***]

"Senegal State Share" is as defined in Clause 3.1.1(C).

"**Seven Day Rule LNG**" means the quantity of LNG scheduled in the Annual Delivery Programme and Specific Delivery Schedule for a Contract Year and which is actually delivered by the Seller Group and taken by the Buyer between 1 and 7 January (both dates included) of the immediately following Contract Year (which Seven Day Rule LNG shall not be considered as having been made available by the Seller Group and taken by the Buyer in such immediately following Contract Year).

"SIGTTO" means the Society of International Gas Tanker and Terminal Operators.

"SIRE" means OCIMF's Ship Inspection and Report Programme.

"Specifications" is as defined in Clause 14.1.

"Specific Delivery Schedule" or **"SDS"** is as defined in Clause 10.4.1.

"St-Louis Owners" means the parties who hold a participating interest in the St-Louis PSC from time to time, being PETROSEN, BPSIL and KEISL at the date of this Agreement.

"St-Louis PSC" means the hydrocarbon exploration and production contract covering the Saint-Louis Offshore Profond Block Contract Area offshore Senegal dated 17 January 2012 and effective on 19 June 2012 to which PETROSEN, BPSIL and KEISL are parties at the date of this Agreement.

"Standard Cubic Foot" or **"SCF"** means a quantity of Natural Gas which at sixty degrees Fahrenheit (60°F) and at an absolute pressure of fourteen decimal six nine six (14.696) pound per square inch and when free of water vapour occupies the volume of one (1) cubic foot.

"States" means the Islamic Republic of Mauritania and the Republic of Senegal.

“State’s Account” is as defined in Clause 12.3.4.

"Target Period" is as defined in Clause 5.1.1.

"Tax" and **"Taxation"** means all forms of taxation whether direct or indirect and whether levied by reference to income, profits, gains, net wealth, asset value, turnover, added value or other sales tax, and statutory governmental, state, provincial, local government or municipal imposition duties, contributions, rates and levies (including any payroll taxes and customs duties), wheresoever imposed, collected or administered (whether by way of a withholding or deduction for or on account of tax or otherwise) and in respect of any Person, and all penalties, charges, costs and interest relating thereto, but excluding any Port Charges.

“Therm” means one hundred and five million, five hundred and five thousand, five hundred and sixty (105,505,560) Joules.

"Third Party" means any Person who is (i) not a Party to this Agreement or (ii) an Affiliate of a Party to this Agreement, or (iii) a joint venture entity set up by two or more Parties to this Agreement for purposes of exercising rights or obligations with respect to this Agreement.

[***]

"Third Window Period" is as defined in Clause 5.1.4.

"Trade Sanctions" means any laws or regulations relating to economic or financial sanctions or trade embargoes or travel bans or related restrictive measures imposed, administered or enforced from time to time by a Sanctions Authority.

"Transfer" means, in respect of any Upstream Participating Interest, any sale, assignment, transfer, relinquishment, withdrawal, forfeiture or other disposition by a Seller of all or part of such Upstream Participating Interest and, in respect of such Seller’s LNG SPA Participation, any transfer of its rights, interests, obligations and liabilities in such LNG SPA Participation (and references to “**Transferred**” and “**Transferring**” shall be construed accordingly).

“Transfer Date” is as defined in Clause 3.1.5.

“Transferee” is as defined in Clause 3.1.4.

“Transferee Rejection Notice” is as defined in Clause 3.1.4.

“Transferring Proportion” is as defined in Clause 3.1.4.

"Transporter" means Buyer or any Person other than the Buyer who owns, operates and/or contracts with the Buyer for the purposes of providing and/or operating an Approved LNG Ship.

"UK" means the United Kingdom of Great Britain and Northern Ireland.

"Upstream Facilities" means the Natural Gas wells and subsea gathering/delivery facilities, transportation facilities, a floating production, storage and offloading vessel, a domestic Natural Gas pipeline connection for Mauritania, a domestic Natural Gas pipeline connection for Senegal, a Feed Gas supply pipeline and the LNG Hub Facilities, and any other associated facilities that shall be constructed or have been constructed for the production of Natural Gas from the Gas Supply Area and the supply of such Natural Gas as Feed Gas to the FLNG Facility and any Future Facilities.

"Upstream Participating Interest" means, with respect to each Seller, the undivided interest of such Seller (expressed as a percentage of the total interests of all of the Seller Group) in the rights and obligations of the Gas Supply Area, which as of the Effective Date is set out in Clause 3.1.1.

“Upstream Transfer” is as defined in Clause 3.1.4.

"Used Laytime" is as defined in Clause 9.12.3.

“UUOA” means that certain Unitization and Unit Operating Agreement by and among SMHPM, BPMIL, KEM, PETROSEN, BPSIL and KEISL dated 7 February 2019 for the Greater Tortue/Ahmeyim field.

[***]

“**Wholly Owned Affiliate**” means, in respect of any Person, an Affiliate of such Person all of whose voting share capital is, directly or indirectly, owned by such Person.

"Winding-Up" of a Person includes the amalgamation, reconstruction, re-organisation, administration, dissolution, liquidation, merger or consolidation of such Person or any equivalent or analogous procedure under the Law of any jurisdiction in which such Person is incorporated, domiciled or resident, carries on business, or has assets.

1.2 **Interpretation**

In this Agreement, except to the extent that the context requires otherwise:

1.2.1 references to a law, or to a provision of it, shall be construed, at any particular time, as including a reference to any modification, extension or re-enactment of it at any time then in force and to all subordinate legislation and regulations made from time to time under it;

1.2.2 references to this Agreement include its Schedules, and references to paragraphs, Clauses, Recitals, Schedules or Appendices are references to such provisions of this Agreement;

1.2.3 references in the singular shall include references in the plural and vice versa, words denoting any gender shall include any other gender and words denoting natural Persons shall include any other Persons;

1.2.4 headings shall be ignored in construing this Agreement;

1.2.5 no Authorisation shall be treated as having been granted for the purposes of this Agreement unless such Authorisation has been finally granted or issued by the relevant Competent Authority without such grant or issue being subject to any appeal or any condition as to its effectiveness;

1.2.6 references to an agreement, deed, instrument, licence, code or other document (including this Agreement), or to a provision contained in any of these, shall be construed, at the particular time, as a reference to it as it may then have been amended, varied, supplemented, modified, suspended, assigned or novated;

1.2.7 references to times of day are to local time at the place where the relevant right or obligation is to be performed unless otherwise stated;

1.2.8 in computing any period of time under this Agreement the day of the act, event or default from which such period begins to run shall not be included. Unless this Agreement provides otherwise, any payment falling due on a non-Business Day shall be deemed to be due and payable on the next following Business Day;

1.2.9 the language that governs the interpretation of this Agreement is the English language. All notices to be given by any Party and all other communications and documentation between the Parties that are in any way relevant to this Agreement or the performance or termination of this Agreement shall be in the English language;

1.2.10 a reference to **"writing"** includes any means of reproducing words in a tangible and permanently visible form (including facsimile or email transmissions);

1.2.11 a reference to a **"day"** means a calendar day;

1.2.12 a reference to a **"month"** means a calendar month;

1.2.13 a reference to a **"year"** means a calendar year under the Gregorian calendar;

1.2.14 a reference to **"encumbrance"** includes without limitation, any claim, mortgage, pledge, lien, option, charge, assignment by way of security, security interest, title retention, equitable right, power of sale, usufruct, retention of title, right of pre-emption, right of first refusal or preferential right or trust arrangement or any other security agreement or arrangement or other Third Party right having the effect of security;

1.2.15 a reference to a **"judgment"** includes any order, injunction, determination, award or other judicial or arbitral measure in any jurisdiction;

1.2.16 the words **"include"** and **"including"** are to be construed without limitation;

1.2.17 a reference to a **"Person"** includes any person, firm, company, corporation, Competent Authority, or any association, trust or partnership (whether or not having separate legal personality) or two or more of the foregoing;

1.2.18 wherever in this Agreement, a matter is stated to be in the **"sole discretion"** or **"sole opinion"** of a Party, to the fullest extent permitted by applicable Law, the discretion may be exercised by the relevant Party without any justification and for any or no reason, and the exercise of such discretion shall not be capable of being challenged in any legal or arbitral proceeding and shall not be a matter that constitutes a Dispute for the purposes of Clause 23; and

1.2.19 wherever in this Agreement a Party is permitted to "inspect" anything, it is understood that such Party may act through an independent inspector or through its Representative.

1.3 Several obligations

All liabilities and obligations of the Sellers under this Agreement shall be several and not joint and several, and no Seller shall have any liability or obligation arising out of a breach by another Seller of its obligations, representations, warranties or undertakings in this Agreement.

1.4 Conflicts

In the event of any inconsistency between the main body of this Agreement and its Schedules then, unless specified otherwise, the main body of this Agreement shall prevail to the extent of the inconsistency.

1.5 Rounding of Numbers

For the purposes of this Agreement, rounding shall be done to four (4) decimal places in accordance with ISO 80000-1:2009(en), Annex B, relating to rules for the rounding of numbers.

2. SALE AND PURCHASE

2.1 Sale and Purchase

During the Commissioning Period and the Contract Term, the Seller Group agrees to make available for delivery and sell to the Buyer or pay damages for if not made available and the Buyer agrees to take and pay for, or pay damages for if not taken, LNG at the Delivery Point in accordance with the terms and conditions of this Agreement.

2.2 Gas Supply Area

2.2.1 Subject to the terms of this Agreement, all LNG produced from the Gas Supply Area at the FLNG Facility during the Commissioning Period, and the AACQ and the In Year Surplus Quantity during the remainder of the Contract Term, shall be tendered for delivery and sold by the Seller Group to the Buyer, and shall be taken and paid for, or paid for if not taken, by the Buyer, in each case in accordance with the terms and conditions of this Agreement. [***].

2.2.2 The Parties acknowledge and agree that, prior to the Effective Date, the Seller Group has furnished to the Buyer a Reserves Certificate evidencing reserves in the Gas Supply Area, [***] To the extent the Seller Group from time to time obtains or receives an updated or new Reserves Report or Reserves Certificate, the Seller Group's Representative shall, at Seller Group's expense, provide the Buyer with a copy of such updated or new Reserves Report or Reserves Certificate within sixty (60) days of the Seller Group's receipt thereof. If the Seller Group obtains a Deliverability Report, the Seller Group's Representative shall, at Seller Group's expense, provide the Buyer with a copy of such Deliverability Report within sixty (60) days of the Seller Group's receipt thereof.

2.2.3 If at any time the Seller Group becomes aware of an event or circumstance causing a change to the installed facilities or the Deliverability that could reasonably be expected to materially and negatively impact the Seller Group's ability to fulfil the Seller Group Supply Obligation, the Seller Group will inform the Buyer and discuss with the Buyer an action plan, based on all available LNG quantities attributable to the Gas Supply Area, to address the deficiency. If at any time the Buyer becomes aware of an event or circumstance causing a change to an Approved LNG Ship that could reasonably be expected to materially and negatively impact the Buyer's ability to load and take delivery of LNG, the Buyer will inform the Seller Group and discuss with the Seller Group an action plan to address the deficiency.

2.2.3(A) [***]

2.2.4 From time to time and at any time, the Seller Group may, but shall not be obligated to, make available to the Buyer in satisfaction of its obligations hereunder LNG that has been produced (i) using Natural Gas from another gas field within the Block C8 PSC or the St-Louis PSC but outside of the Gas Supply Area, at the FLNG Facility or the Future GTA Project; and/or (ii) from any other LNG facility in Mauritania or Senegal, so long as all of the following conditions are met:

(A) the Seller Group shall notify the Buyer of the source of such substitute LNG as soon as reasonably practicable and in any event at least [***] before the Arrival Window;

(B) the Seller Group shall reimburse the Buyer for any additional costs the Buyer incurs in receiving such LNG;

(C) where such LNG has been produced using Natural Gas from another gas field under (i) above and/or from another LNG facility in Mauritania or Senegal under (ii) above, the Seller Group shall not be entitled to assert any rights under Clause 16.1 in respect of any failure to make Natural Gas available from such other gas field or LNG available from such other LNG facility under this Clause 2.2.4;

(D) the facilities from which the LNG is delivered to the Buyer shall (i) be compatible in all respects with the Approved LNG Ships, (ii) comply with the provisions of Clause 9.4 and 9.5, (iii) have been reviewed and accepted by Buyer's marine assurance department, such acceptance not to be unreasonably withheld or delayed, and the conditions of use and facilities manual for such facilities meet the Conditions of Use Requirements, and (iv) at the time of nomination of such facilities, they are not subject to or reasonably likely to become subject to, a Force Majeure Event before the delivery of the substitute LNG;

(E) the LNG shall comply with the Specifications;

(F) the receipt of the substitute LNG will not change the Arrival Window or Scheduled Loading Quantity for the relevant Cargo; and

(G) such change does not, in the reasonable opinion of the Buyer, affect the Buyer's ability to arrive at the Loading Terminal within the Arrival Window and deliver the LNG at the applicable unloading terminal in accordance with its unloading schedule.

Notwithstanding the above, the Seller Group shall not have the right to make available LNG that has been produced using Natural Gas from another gas field and/or LNG from any other LNG facility in Mauritania or Senegal if the commissioning of such other gas field or LNG facility has not been completed at the time of such notification under Clause 2.2.4(A) above.

[***]

2.3 Third-Person Natural Gas or LNG Sales

Without prejudice to Clause 2.2.1, the Seller Group and any individual Seller shall have the right to sell Natural Gas and/or LNG produced from Natural Gas produced from the Gas Supply Area to any Person, provided that neither the Seller Group nor any individual Seller shall enter into any agreement with any Person for the sale of Natural Gas and/or LNG produced from Natural Gas produced from the Gas Supply Area if the effect of such sale would result in the Reserves or Deliverability, based on the most recent information available to the Seller Group in respect of Reserves, Deliverability, the capacity of the GTA Project and Future GTA Project, including information in the latest Reserves Report or Reserves Certificate, and Deliverability Report (if one is prepared) ("**Latest Reserves and Deliverability Information**"), being insufficient to meet the Seller Group Supply Obligation. Before entering into any additional commitment of Natural Gas and/or LNG produced from Natural Gas produced from the Gas Supply Area, the Seller Group shall furnish such most recent information to the Buyer. [***]

2.4 Destination of LNG

After taking delivery of LNG at the Delivery Point under this Agreement, the Buyer shall have the unfettered right thereafter to transport and/or deliver such LNG to any port and to any buyer in its sole discretion, provided that the Buyer's deliveries to such country or buyer would not be in contravention of any Laws and/or Trade Sanctions applicable to the Seller Group or the Buyer, provided further that with respect to Trade Sanctions adopted by the States of Mauritania or Senegal, compliance by the Buyer shall be subject to the Buyer first having received written notification of such Trade Sanctions from the Seller Group or from the Competent Authorities in Mauritania or Senegal, as applicable, prior to taking delivery of the LNG.

3. SELLER GROUP

3.1 LNG SPA Ownership

3.1.1 (A) As at the Effective Date, each Seller's respective Upstream Participating Interest is as follows:

(i) SMHPM: seven per cent (7%);

(ii) BPMIL: twenty-nine decimal six, two, two, two per cent (29.6222%);

(iii) KEM: thirteen decimal three, seven, seven, eight per cent (13.3778%);

(iv) PETROSEN: ten per cent (10%);

(v) BPSIL: twenty-six decimal six, six, six, seven per cent (26.6667%); and

(vi) KEISL: thirteen decimal three, three, three, three per cent (13.3333%)

(B) Subject to the following sentence of this Clause 3.1.1(B), the share of LNG committed for sale under this Agreement to which the Islamic Republic of Mauritania is entitled under the Block C8 PSC ("**Mauritania State Share**") will be taken in cash (as described in Article 10.6 of the Block C8 PSC) by the Islamic Republic of Mauritania, and will therefore be sold under this Agreement by SMHPM, BPMIL and KEM pro rata to their Upstream Participating Interests under the Block C8 PSC. The Islamic Republic of Mauritania may make an election, by notice in writing issued by the Minister to SHMPM, BPMIL and KEM at any time within [***] after the Effective Date, to take the Mauritania State Share in kind under the Block C8 PSC (as described in Article 10.5 of the Block C8 PSC). In such case, the Mauritania State Share shall thereafter be sold by SMHPM, from the effective date of the Minister's notice, and the LNG SPA Participations below shall be adjusted accordingly with effect from the date of the Minister's notice. The Seller Group shall notify the Buyer promptly following receipt of the Minister's notice, together with the adjusted LNG SPA Participations. [***]

(C) Subject to the following sentence of this Clause 3.1.1(C), the share of LNG committed for sale under this Agreement to which the Republic of Senegal is entitled under the St-Louis PSC ("**Senegal State Share**") will be taken in cash (as described in Article 22.8 of the St-Louis PSC) by the Republic of Senegal, and will therefore be sold under this Agreement by PETROSEN, BPSIL and KEISL pro rata to their Upstream Participating Interests under the St-Louis PSC. The Republic of Senegal may make an election, by notice in writing issued by the Minister to PETROSEN, BPSIL and KEISL at any time within [***] days after the Effective Date, to take the Senegal State Share in kind under the St-Louis PSC (as described in Article 22.8 of the St-Louis PSC). In such case, the Senegal State Share shall thereafter be sold by PETROSEN, from the effective date of the Minister's notice, and the LNG SPA Participations below shall be adjusted accordingly with effect from the date of the Minister's notice. The Seller Group shall notify the Buyer promptly following receipt of the Minister's notice, together with the adjusted LNG SPA Participations. [***]

(D) As at the Effective Date, each Seller's respective LNG SPA Participation is as follows:

(i) SMHPM: seven per cent (7.0%);

(ii) BPMIL: twenty-nine decimal six, two, two, two per cent (29.6222%);

(i) KEM: thirteen decimal three, seven, seven, eight per cent (13.3778%);

(ii) PETROSEN: ten per cent (10%);

(iii) BPSIL: twenty-six decimal six, six, six, seven per cent (26.6667%); and

(iv) KEISL: thirteen decimal three, three, three, three per cent (13.3333%).

The Sellers identified above, together with the Republic of Senegal and the Islamic Republic of Mauritania, together represent 100% of the parties with an entitlement to production of Natural Gas from the Gas Supply Area.

3.1.2 Each Seller confirms that its respective LNG SPA Participation is identical to its respective Upstream Participating Interest as at the Effective Date, on the basis that the Mauritania State Share is taken in cash by the Islamic Republic of Mauritania as described in Clause 3.1.1(B) and the Senegal State Share is taken in cash by the Republic of Senegal as described in Clause 3.1.1(C) above. If the Islamic Republic of Mauritania and/or the Republic of Senegal elect to take their share in kind pursuant to Clause 3.1.1(B) or Clause 3.1.1(C), the LNG SPA Participations shall be adjusted accordingly and may thereafter vary from time to time in accordance with the production-sharing mechanisms of the Block C8 PSC and the St-Louis PSC, provided always that the aggregate LNG SPA Participations shall equal one hundred percent (100%). The Parties further acknowledge that the Upstream Participating Interests may be adjusted from time to time pursuant to redetermination carried out under the terms of the ICA and UUOA, provided always that the aggregate Upstream Participating Interests shall equal one hundred percent (100%). The Seller Group's Representative shall promptly notify the Buyer of any change to the LNG SPA Participations which may occur from time to time pursuant to such redeterminations and/or in accordance with the terms of the C-8 PSC and/or the St-Louis PSC. For the avoidance of doubt, any such change to LNG SPA Participations shall not require the consent or approval of the Buyer.

3.1.3 No Seller shall Transfer all or any part of its Upstream Participating Interest other than together with a corresponding Transfer of its LNG SPA Participation. For the avoidance of doubt, and subject to Clause 24 and each Seller’s compliance with Clause 3.1.4, any Transfer of an Upstream Participating Interest shall not require the consent of the Buyer.

3.1.4 If any Seller (a “**Transferring Seller**”) intends to Transfer all or any part of its Upstream Participating Interest and a corresponding part of its LNG SPA Participation (such corresponding part of its LNG SPA Participation being the “**Transferring Proportion**”) to any Person (such Person being the “**Transferee**”, and such Transfer being an “**Upstream Transfer**”), then:

(A) the Transferring Seller agrees to notify the Buyer prior to the completion of such Upstream Transfer, which notice shall specify the Upstream Participating Interest proposed to be Transferred and reasonable details of the Transferee; and

(B) if the proposed Transferee:

(1) is a Seller prior to the date of the Upstream Transfer, then upon completion of the Upstream Transfer the Transferring Seller shall procure that such Transferee shall enter into a deed of novation with such Transferring Seller in the form set out in Schedule 9, pursuant to which such Transferee agrees to assume all of the liabilities, duties and obligations of the Transferring Seller in respect of the Transferring Proportion (the “**Deed of Novation**”); or

(2) **is not a Seller prior to the date of the Upstream Transfer, then the Transferring Seller shall procure that such Transferee shall provide the Buyer with such information as may be required by the Buyer (acting reasonably) as part of the Buyer’s customary “know your customer” and similar due diligence procedures (the “Due Diligence Requests”)** [***]

3.1.5 With effect from the date that the relevant Upstream Transfer and Deed of Adherence or Deed of Novation become effective (the "**Transfer Date**"):

(A) the LNG SPA Participations of the Sellers under this Agreement shall be automatically amended in order to reflect the Transfer of the Transferring Proportion from the Transferring Seller to the Transferee;

(B) the Transferee shall enjoy all rights arising out of or in respect of the Transferring Proportion and shall have the right to enforce its rights under this Agreement in respect of the Transferring Proportion and pursue all claims and demands (future or existing) whatsoever arising out of or in respect of the Transferring Proportion arising before, on or after to the Transfer Date;

(C) the Transferee shall assume all the liabilities, duties and obligations of the Transferring Seller of every description in respect of the Transferring Proportion, whether deriving from contract, common law, statute or otherwise, whether arising before, on or after the Transfer Date, actual or contingent, ascertained or unascertained or disputed and agrees to perform all the duties and to discharge all the liabilities and obligations of the Transferring Seller in respect of the Transferring Proportion and to be bound by the terms and conditions of this Agreement in every way as if the Transferee was an original Party to this Agreement in place of the Transferring Seller in respect of the Transferring Proportion;

(D) the Transferring Seller shall have no further liabilities, duties and obligations of any description, whether deriving from contract, common law, statute or otherwise, whether arising before, on or after the Transfer Date, actual or contingent, ascertained or unascertained or disputed, owing to the Buyer and arising out of or in respect of the Transferring Proportion; and

(E) the Buyer shall have no further liabilities, duties and obligations of any description, whether deriving from contract, common law, statute or otherwise, whether arising before, on or after the Transfer Date, actual or contingent, ascertained or unascertained or disputed, owing to the Transferring Seller and arising out of or in respect of the Transferring Proportion.

3.1.6 The Buyer agrees to perform all its duties and to discharge all its obligations under this Agreement in respect of the Transferring Proportion and to be bound by all the terms and conditions of this Agreement in every way as if the Transferee was an original Party to this Agreement in place of the Transferring Seller in respect of the Transferring Proportion.

3.2 **Seller Group's Relationship**

3.2.1 Each Seller confirms that this Agreement is not intended to create and shall not be construed as creating, between each or any members of the Seller Group, a partnership, joint venture or association or any fiduciary obligations whatsoever.

3.2.2 Unless otherwise expressly provided in this Agreement, all rights, interests, obligations and liabilities of the Seller Group in and under this Agreement shall be held (in the case of rights and interests) or owed (in the case of obligations and liabilities) by each Seller severally, and not joint and severally, in proportion to their respective LNG SPA Participations.

3.2.3 Pursuant to this Clause 3.2:

(A) except to the extent provided in Clause 3.3.3, the rights, obligations and liabilities of each Seller under this Agreement shall be exercised through the Seller Group's Representative; and

(B) acts or omissions of the Seller Group's Representative in accordance with Clause 3.3.2 shall be deemed to be acts or omissions of each Seller in its LNG SPA Participation, except in respect of any matters specifically referred to in Clause 3.3.3.

3.3 **Seller Group's Representative**

3.3.1 The Seller Group hereby nominates an unincorporated venture of BPMIL and BPSIL to act as the Seller Group's Representative for the purposes of this Agreement.

3.3.2 Except as provided in Clause 3.3.3, each Seller hereby irrevocably:

(A) appoints the Seller Group's Representative as its sole representative for the purposes of administering this Agreement and any Acceptable Credit Support and for the purposes of sending on behalf of the Seller Group and receiving all notices and invoices in relation to this Agreement and any Acceptable Credit Support;

(B) confirms that the Seller Group's Representative shall act as the sole and exclusive representative of each Seller within the scope of the authority under this Agreement for the purposes of this Agreement and any Acceptable Credit Support provided by the Buyer; and

(C) subject to Clause 3.3.3, confers full authority on the Seller Group's Representative to perform all acts, matters and things which this Agreement requires or permits the Seller Group or the Seller Group's Representative to perform,

until the date (if any) on which the Seller Group's Representative is replaced in accordance with Clause 3.3.5.

3.3.3 [***]

(A) [***]

(B) [***]

(C) [***]

(D) [***]

(E) [***]

(F) [***]

(G) [***]

(H) [***]

3.3.4 Except as the Sellers may otherwise specify by joint notice to the Buyer signed by a duly authorised representative of each Seller, each of the matters in Clauses 3.3.3 may only be performed by the Sellers individually or collectively as applicable.

3.3.5 Each Seller agrees with the Buyer not to replace the Seller Group's Representative without the Seller Group giving not less than fifteen (15) days prior written notice to the Buyer of the replacement Seller Group's Representative. The Seller Group's Representative shall have no liability to the Buyer for its acts, omissions or things done in its capacity as the Seller Group's Representative, provided always that each Seller shall remain liable to the Buyer severally in proportion to its respective LNG SPA Participation for any acts or omissions of the Seller Group's Representative under this Agreement as if those acts or omissions were those of the Seller Group.

3.3.6 The Buyer may not take any proceedings against any officer, employee or agent of the Seller Group's Representative in respect of any claim it might have against the Seller Group's Representative in its performance of (or in respect of any act or omission of any kind by that officer, employee or agent in undertaking such performance of the Seller Group's Representative under) this Agreement and any officer, employee or agent of the Seller Group's Representative may rely on this Clause 3.3.6.

3.3.7 Nothing in this Agreement constitutes the Seller Group's Representative as a trustee or fiduciary of any other Person.

4. EFFECTIVE DATE AND REPRESENTATIONS AND WARRANTIES

4.1 Effective Date

The provisions of this Agreement shall become effective upon the date of final signature by all Parties and both States (the **"Effective Date"**).

4.2 Representations and Warranties

Each Party hereby represents and warrants to the other Parties that as of the Effective Date:

4.2.1 it is an entity duly organised, validly existing and in good standing under the Laws of the jurisdiction of its organisation;

4.2.2 it has full power and authority to enter into and perform its obligations under this Agreement;

4.2.3 the actions necessary to authorise the execution and delivery of this Agreement and the performance of its obligations under this Agreement have been duly taken;

4.2.4 this Agreement has been duly executed and delivered by its duly authorised officer or other representative and constitutes its legal, valid and binding obligation enforceable in accordance with its terms, except to the extent such enforceability may be affected by applicable bankruptcy, reorganisation, insolvency, moratorium or other similar Laws affecting creditors' rights generally, and except that the availability of equitable remedies is subject to judicial discretion;

4.2.5 no consent or approval of any Person is required in connection with the execution, delivery and performance of this Agreement by it; and

4.2.6 the execution, delivery and performance of this Agreement does not violate its organisational documents or any material agreement or any applicable Laws by which it or its assets are bound.

5. COMMISSIONING

5.1 Commissioning Start Date and Commissioning Period

Following the completion of the construction of the FLNG Facility, the Seller Group shall procure the commissioning and testing of the FLNG Facility during the period commencing on the Commissioning Start Date and ending on the day before the Commercial Operations Date (the **"Commissioning Period"**). The Commissioning Start Date shall be determined in accordance with the following provisions of this Clause 5.1.

5.1.1 The Commissioning Start Date is expected to occur during the period commencing on [***] (the **"Target Period"**).

5.1.2 The Seller Group's Representative shall notify the Buyer at least one hundred and eighty (180) days prior to the first day of the Target Period of a ninety (90) day period within the Target Period during which the Seller Group intends the Commissioning Start Date to occur (the **"First Window Period"**).

5.1.3 The Seller Group's Representative shall notify the Buyer at least ninety (90) days prior to the first day of the First Window Period of a thirty (30) day period within the First Window Period during which the Seller Group intends the Commissioning Start Date to occur (the **"Second Window Period"**).

5.1.4 The Seller Group's Representative shall notify Buyer at least thirty (30) days prior to the first day of the Second Window Period of a fifteen (15) day period within the Second Window Period during which the Seller Group intends the Commissioning Start Date to occur (the **"Third Window Period"**).

5.1.5 The Seller Group's Representative shall notify the Buyer at least fifteen (15) days prior to the first day of the Third Window Period of the day within the Third Window Period that shall be the Commissioning Start Date.

5.1.6 The Seller Group's Representative shall provide to the Buyer the following information, and any updates to such information, following receipt of such information from the LNG Hub Facilities Operator:

(A)any changes to the date (previously notified pursuant to the foregoing provisions of this Clause 5.1) on which the Commissioning Start Date is expected to occur; and

(B)the quantities of LNG (in cubic metres and MMBtu) expected to be produced and made available for delivery during the Commissioning Period.

5.1.7 In the event that the Seller Group's Representative fails to give any notice provided for herein by the applicable deadline date for giving such notice, the Seller Group shall be deemed to have notified the date or period, as applicable, which is the latest possible such date or period falling within the relevant window period.

5.1.8 Without prejudice to the above provisions in this Clause 5.1, no later than twenty (20) days following the Effective Date, the Seller Group's Representative shall provide the Buyer with a copy of the project schedule, following which it shall provide monthly updates to the schedule (each a **"Monthly Project Update"**). The project schedule and the Monthly Project Updates shall include Seller Group's non-binding estimates for (i) the Commissioning Start Date, (ii) the matters described in Clauses 5.1.6(B) and 5.2.1(B); and (iii) after the Seller Group takes a final investment decision on the Future Facilities, which shall be promptly notified by the Seller Group to the Buyer, the Future Facilities Commissioning Start Date and Future Facilities Commercial Operations Date. In addition, each monthly update shall provide progress reporting measurements and metrics, a summary of activities and accomplishments from the last Monthly Project Update, planned activities for the upcoming reporting period and any issues that could impact on the schedule.

5.2 **Commercial Operations Date**

5.2.1 The Seller Group shall use reasonable endeavours to procure that the Commercial Operations Date occurs as soon as reasonably practicable following the Commissioning Start Date and shall, on or before the Commissioning Start Date and from time to time thereafter, notify and update the Buyer of the Seller Group's estimates of the following:

(A) the matter described in Clause 5.1.6(B); and

(B) the date on which the Commercial Operations Date is expected to occur.

5.2.2 [***]

5.2.3 [***]

5.2.4 The Seller Group's Representative shall notify the Buyer in writing of the LOA Commercial Operations Date.

5.3 **Commissioning Cargoes**

5.3.1 The Seller Group shall offer to the Buyer all LNG cargoes which are produced from the FLNG Facility and which are made available to the Seller Group during the Commissioning Period (each a **"Commissioning Cargo"**), and the Buyer shall take each Commissioning Cargo at the applicable Commissioning Period Price. [***]

5.3.2 The Seller Group and the Buyer shall promptly co-operate and exchange information relating to all relevant HAZOP and risk management activities specific to the commissioning of the FLNG Facility and LNG Hub Facilities that affect Cargo loading operations and interfaces with an Approved LNG Ship

5.3.3 No later than sixty (60) days before the start of the Second Window Period, the Seller Group's Representative shall provide the Buyer with a draft operational plan for the safe and efficient loading of the first Commissioning Cargo. The plan shall reflect information exchanged under Clause 5.3.2. No later than forty-five (45) days prior to the start of the Arrival Window for the first Commissioning Cargo and, at the Buyer's request, subsequent Commissioning Cargoes, the Seller Group's Representative, the Buyer, the LNG Hub Facilities Operator and the operator of the Approved LNG Ship onto which the Buyer proposes to load the Commissioning Cargo shall meet to discuss and agree the final version of such operational plan for the first Commissioning Cargo and subsequent Commissioning Cargoes as applicable.

5.3.4 The Seller Group shall use reasonable endeavours to provide the Buyer with as much advance notice as is reasonably practicable of each Commissioning Cargo and shall in any event give notice in accordance with this Clause 5.3.4 no later than [***] days prior to the start of the Arrival Window for such Commissioning Cargo. In each notice to the Buyer identifying a Commissioning Cargo, the Seller Group's Representative shall specify for such Commissioning Cargo:

(A) the Arrival Window;

(B) the expected loading rate and any operational circumstances which may affect the FLNG Facility, the LNG Hub Facilities or the loading operations;

(C) for information purposes only, the expected laytime (without amending the Allowed Laytime) for such Commissioning Cargo;

(D) the Scheduled Loading Quantity which shall be:

(1) [***]

(2) for each subsequent Commissioning Cargo, a quantity required to fully load an Approved 174 LNG Ship or an Approved 155 LNG

Ship, at the Buyer's election, unless otherwise agreed between Buyer and Seller Group (acting reasonably),

each being the "**Commissioning Cargo Quantity**", as applicable.

The Buyer shall use reasonable endeavours to provide the Seller Group with as much advance notice as is reasonably practicable of the name of the Approved LNG Ship for each Commissioning Cargo and shall in any event give notice no later than [***] prior to the start of the Arrival Window for such Commissioning Cargo. This provision shall be without prejudice to the Buyer's right to replace the Approved LNG Ship with a substitute Approved LNG ship in accordance with Clause 10.5.6.

5.3.5 For each Commissioning Cargo satisfying the conditions of Clause 5.3.4, subject to Clauses 5.3.8 and 5.3.9, the Seller Group shall make such LNG available for delivery at the Delivery Point, and the Buyer shall take and pay for, or pay damages for if not taken, such Commissioning Cargo, at the time specified in such notice and pursuant to the other terms of this Agreement.

5.3.6 If the Seller Group or the Buyer requests any changes in respect of a Commissioning Cargo, the Parties shall use reasonable endeavours to agree to such changes.

5.3.7 For the avoidance of doubt, subject to Clause 5.3.1, the Seller Group is not obliged to make available to the Buyer any minimum number of Commissioning Cargoes [***].

5.3.8 [***]

(A) [***]

(B) [***]

5.3.9 [***]

(A) [***]

(B) [***]

(C) [***]

(D) [***]

6. **DURATION**

6.1 **Initial Term**

This Agreement shall enter into force and effect on the Effective Date and shall continue in force and effect up to the date which is the earlier of (i) the [***] anniversary of the Commercial Operations Date, (ii) the [***] "Commercial Operations Date Anniversary" as defined in and pursuant to the FLNG Lease and Operate Agreement, which shall be advised by Seller Group to the Buyer; and (iii) 31 December [***], subject to Clause 6.2 and unless terminated earlier in accordance with the provisions of this Agreement.

6.2 **Extension of Contract Term**

6.2.1 Notwithstanding Clause 6.1, but subject to Clause 5.2.3, the Seller Group may, in its sole discretion, elect to extend the term of this Agreement in accordance with this Clause 6.2.

(A) Not less than [***] before the expiry of the Initial Term, the Seller Group may, at its sole discretion, give notice to the Buyer that the term of this Agreement shall be extended up to the date which is [***] after the end of the Initial Term and upon delivery of such notice the term of this Agreement shall be so extended commencing on the day immediately following the day on which the Initial Term would otherwise have ended (the "**First Extension Term**").

(B) Not less than[***] before the expiry of the First Extension Term, the Seller Group may, at its sole discretion, give notice to the Buyer that the term of this Agreement shall be extended up to the date which is the [***] after the end of the First Extension Term and upon delivery of such notice the term of this Agreement shall be so extended commencing on the day immediately following the day on which the First Extension Term would otherwise have ended (the "**Second Extension Term**").

(C) The Parties understand and agree that the Contract Price applicable during the First Extension Term and the Second Extension Term will be determined in accordance with Clause 11.6.

6.3 Notwithstanding the provisions of Clause 6.2, in no circumstances may the Contract Term extend beyond the end of the Second Extension Term, if applicable, unless otherwise agreed between the Parties.

6.4 **Make-up Extension**

[***] in no circumstances shall the Buyer be entitled to extend the Contract Term to enable the Buyer to take as Make-Up Quantities any amounts that have accrued at the expiry of such Contract Term.

7. QUANTITIES

7.1 Annual Contract Quantity

7.1.1 The annual contract quantity of LNG in respect of each full Contract Year shall be [***] MMBtu (the **"ACQ"**), which is equivalent to [***] tonnes per annum in accordance with the relevant heating value of the LNG. If a Contract Year contains less than three hundred and sixty-five (365) days, the ACQ shall be adjusted by the same proportion as the proportion to which the number of days in such Contract Year bears to the number of days in the corresponding calendar year.

7.1.2 [***]

(A) [***]

(B) [***]

(C) [***]

(D) [***]

(E) [***]

(F) [***]

(G) [***]

(H) Any Cargo Deliver or Pay Obligation or Cargo Take or Pay Obligation arising in respect of any quantities to be delivered to Buyer under Clause 7.1.2(D) shall be determined by reference to a blended Cargo Deliver or Pay Price or Cargo Take or Pay Price calculated by reference to the proportionate share of the Cargo to be priced at the Base Contract Price and the proportionate share of the Cargo to be priced at [***].

(I) The Buyer shall have the right to cause a Third Party auditor to verify any calculations of quantities of LNG or entitlements described in this Clause 7.1.2 in accordance with Clause 19.3.

7.1.3 Scheduled Downtime

(A) In respect of any Contract Year, the Seller Group may notify the Buyer that the receipt, treatment and liquefaction of Feed Gas by, and storage and offloading of LNG from, the FLNG Facility and/or the Future Facilities is to be temporarily halted, reduced, curtailed or otherwise modified for the purposes of:

(1) maintaining the Upstream Facilities; and/or

(2) maintaining the FLNG Facility, the LNG Hub Facilities and the Future Facilities,

("**Scheduled Downtime**"), provided such Scheduled Downtime shall not exceed [***].

(B) Such Scheduled Downtime shall be notified by the Seller Group's Representative to the Buyer by the time required in Clause 10.1.3(C) and shall indicate the operational reasons and the reduction to the ACQ in such Contract Year (the "**Scheduled Downtime Quantity**").

7.1.4 Round-Up/Round-Down Quantities

(A) [***]

(B) [***]

(C) [***]

7.2 **Adjusted Annual Contract Quantity**

The quantity of LNG to be sold by Seller Group and to be taken by the Buyer in respect of each Contract Year shall be the Adjusted Annual Contract Quantity (**"AACQ"**), expressed in MMBtu, which shall be calculated as the sum in such Contract Year of:

7.2.1 the ACQ for such Contract Year:

plus

(A) [***]

(B) [***]

less any:

(C) [***]

(D) [***]

(E) [***]

(F) any Scheduled Downtime Quantity notified in accordance with Clause 7.1.3 and Clause 10.1.3; and

(G) [***]

7.3 **Surplus Quantities**

7.3.1 If, at any time during a Contract Year prior to the Future Facilities Commercial Operations Date, the Seller Group wish to produce a quantity of LNG in such Contract Year from the FLNG Facility in excess of the AACQ applicable to such Contract Year (such excess LNG quantity being an **"Offered In Year Surplus Quantity"**), then the Seller Group's Representative shall promptly notify the Buyer, in accordance with Clause 10.5, of:

(1) [***]

(2) [***]

(3) [***]

(4) [***]

(such notice a **"Seller Group's Surplus Notification"**). .

7.3.2 **Acceptance of Offered In Year Surplus Quantities**

(A) If the Seller Group's Surplus Notification meeting the quantity requirements under Clause 7.3.1(1) is received by the Buyer at least [***] prior to the start of the proposed Arrival Window and inclusion of the Offered in Year Surplus Quantity into the Annual Delivery Program or Specific Delivery Schedule does not require any consequent change to the ADP or SDS [***], the Buyer shall be deemed to have accepted the Offered In Year Surplus Quantity.

(B) If the Seller Group's Surplus Notification meeting the quantity requirements under Clause 7.3.1(1) is received by the Buyer less than [***] prior to the start of the proposed Arrival Window or requires any consequent change to the ADP or SDS [***], the Buyer shall use reasonable endeavours to accept the Offered In Year Surplus Quantity and shall notify the Seller Group pursuant to Clause 10.5.4 if it can accept the Offered In Year Surplus Quantity offered in the Seller Group's Surplus Notification.

(C) If the Seller Group's Surplus Notification meets the quantity requirements under Clause 7.3.1(2), the Buyer shall use reasonable endeavours to accept the Offered In Year Surplus Quantity, and shall notify the Seller Group pursuant to Clause 10.5.4 if it can accept such quantity.

(D) If the Seller Group's Surplus Notification meets the quantity requirements under Clause 7.3.1(3), the Buyer may accept the Offered In Year Surplus Quantity in its sole discretion, and shall notify the Seller Group pursuant to Clause 10.5.4 if it can accept such quantity.

If the Buyer does not accept the quantity notified by the Seller Group in Clause 7.3.2(B), 7.3.2(C) or in Clause 7.3.2(D), the Seller Group may dispose of such quantity of LNG in its sole discretion.

7.3.3 If the Seller Group's Surplus Notification is deemed accepted or accepted by the Buyer pursuant to Clause 7.3.2, the Seller Group shall tender for delivery and pay damages for if not delivered such surplus quantity (**"In Year Surplus Quantity"**), and the Buyer shall take and pay for, or pay damages for if not taken, such In Year Surplus Quantity in accordance with the terms of this Agreement at the applicable [***].

7.3.4 If the Buyer is unable to accept delivery of such Offered In Year Surplus Quantity pursuant to Clauses 7.3.2(B) or 7.3.2(C), or does not accept delivery of such Offered In Year Surplus pursuant to Clause 7.3.2(D), it shall notify the Seller Group in accordance with Clause 10.5.4 within [***] of its receipt of the Seller Group's Surplus Notification and the Buyer will not be required to take or pay for such Offered In Year Surplus Quantity and the Seller Group shall be entitled to offer the Offered In Year Surplus Quantity specified in such Seller Group's Surplus Notification to any Third Party.

7.3.5 [***]

7.4 **Buyer's Obligation to Take or Pay**

7.4.1 If, in respect of a Commissioning Cargo or a Cargo scheduled during the Contract Term, for any reason other than:

(A) a Buyer's Force Majeure;

(B) a Seller's Force Majeure;

(C) Adverse Weather;

(D) Buyer's rejection of the relevant Cargo in accordance with Clause 14;

(E) for fault of the FLNG Provider, the FLNG Facility Operator, an EPC contractor or sub-contractor engaged on the construction of the Seller Group’s Facilities, or the Seller Group or the LNG Hub Facilities Operator or the owner or crew of the FLNG Facility and/or the LNG Hub Facilities [***] in each case not excused by the terms of this Agreement;

(F) [***]

the Buyer:

(1) notifies the Seller Group that it will not take such Cargo;

(2) fails to (or earlier notifies the Seller Group that it will fail to) tender a Notice of Readiness within [***] hours after the end of the Arrival Window; or

(3) fails to take delivery of all or any part of the Commissioning Cargo Quantity notified in accordance with Clause 5.3.4 or the Scheduled Loading Quantity, as applicable, within [***] hours after the end of Permitted Time, provided that where a Notice of Readiness is tendered within [***] hours after the end of the Arrival Window, the [***]hour period (after the end of Permitted Time) shall be reduced by *“**x**”*, where, for the purpose of this clause, *“**x**”* means the number of hours after the end of the Arrival Window that the Notice of Readiness is tendered,

then, unless otherwise agreed by the Parties in respect of alternative delivery arrangements for the Cargo within [***] hours of the event specified in Clauses 7.4.1(1), (2) or (3) occurring (using reasonable endeavours to do so), the Seller Group shall have the right to, as applicable, cancel or stop the loading of the Cargo and require the Approved LNG Ship to depart from the LNG Hub Facilities. [***] the Seller Group shall invoice the Buyer, in accordance with Clause 12.2.1, an amount equal to the difference between the Commissioning Cargo Quantity notified in accordance with Clause 5.3.4(D) or the Scheduled Loading Quantity, as applicable, for the relevant Cargo and the quantity loaded (if any) (a "**Cargo Take or Pay Quantity**") multiplied by the applicable Contract Price in effect at the start of the Arrival Window for such Cargo (the "**Cargo Take or Pay Price**"). Where a Cargo contains quantities to be priced at both the Base Contract Price and [***], a blended Take or Pay Price calculated based on the proportionate share of the Cargo to be priced at the Base Contract Price and the proportionate share of the Cargo to be priced at the [***] shall apply for the purpose of this Clause 7.4.1. The Buyer shall pay such amount so invoiced in accordance with Clause 12.3.2. The Cargo Take or Pay Quantity multiplied by the Cargo Take or Pay Price shall be the "**Cargo Take or Pay Obligation**".

7.4.2 The Parties hereby acknowledge and agree that the Cargo Take or Pay Obligation shall be in the nature of damages and shall be the Seller Group's sole and exclusive remedies in damages or otherwise for failure by the Buyer to take such Cargo and, taking into account the Seller Group's right to offer such LNG to any Third Party and the Buyer's right to any resulting Make-Up Quantities, represents a proportionate protection of the legitimate interests of the Seller Group in connection with the applicable Cargo Take or Pay Quantity.

7.4.3 The [***] hour period in Clauses 7.4.1(2) and the[***] hour period after the Permitted Time in Clause 7.4.1(3) shall become [***] on and after the Future Facilities Commercial Operations Date.

7.5 **Make-Up**

7.5.1 Subject to this Clause 7.5, during the Contract Term the Buyer shall be entitled to take, and the Seller Group shall deliver, any Cargo Take or Pay Quantity that the Buyer has paid for pursuant to Clause 7.4, as a "**Make-Up Quantity**". [***]

7.5.2 Any Make-Up Quantity shall be taken by the Buyer in the chronological order in which it was originally accrued, in any subsequent Contract Year during the Contract Term and shall be notified by the Buyer to the Seller Group's Representative in accordance with Clause 10.1.4.

7.5.3 [***]

(A) [***]

(B) [***]

(C) [***]

7.5.4 Following delivery of any Make-Up Quantity, the Seller Group [***]

7.5.5 If the Buyer fails to take a Make-Up Quantity scheduled in the Specific Delivery Schedule for reasons other than a Force Majeure Event or the fault of the Seller Group (excluding authorized actions of the Seller Group in response to a Buyer default) such Make-Up Quantity shall be treated as delivered, taken and paid for, for the purposes of this Agreement and the Buyer shall have no further rights with respect thereto, and Seller Group shall have no obligation to refund any payments made for such Cargo Take or Pay Obligation.

7.5.6 If the Seller Group fails to make available or the Buyer fails to take a Make-Up Quantity scheduled in the Specific Delivery Schedule by reason of a Force Majeure Event, neither Party shall have any liability to the other Party therefor and the Buyer's right to such Make-Up Quantity shall be re-instated and the Buyer shall be entitled to take such Make-Up Quantity in accordance with the terms of this Clause 7.

7.5.7 If the Seller Group fails to make available a Make-Up Quantity scheduled in the Specific Delivery Schedule for reasons other than a Force Majeure Event or the fault of the Buyer (excluding authorized actions of the Buyer in response to a Seller or Seller Group default), [***]

(A) [***]

(B) [***]

7.5.8 [***]

7.5.9 [***]

7.6 **Seller Group's Obligation to Deliver or Pay**

7.6.1 If, in respect of a Cargo scheduled during the Contract Term, for any reason other than:

(A) a Buyer's Force Majeure;

(B) a Seller's Force Majeure;

(C) Adverse Weather; or

(D) for fault of the Buyer or the Approved LNG Ship or the master of the Approved LNG Ship in each case not excused by the terms of this Agreement,

any of the following occurs:

(1) Seller Group notifies the Buyer that it cancels or will not make available such Cargo; or

Seller Group fails to make available all or part of the Scheduled Loading Quantity within [***] hours after the end of the Permitted Time,

then, unless otherwise agreed by the Parties in respect of alternative delivery arrangements for the Cargo within [***]

hours of the event specified in Clauses 7.6.1(1) or (2) occurring (using reasonable endeavours to do so), the Buyer shall have the right to, as applicable, cancel or stop the loading of the Cargo and instruct the Approved LNG Ship to depart from the LNG Hub Facilities, and the Seller Group shall pay the Buyer an amount equal to the difference between the Scheduled Loading Quantity for the relevant Cargo and the quantity loaded (if any) (a "**Cargo Deliver or Pay Quantity**") multiplied by [***] of the applicable Contract Price in effect at the start of the Arrival Window for such Cargo (the "**Cargo Deliver or Pay Price**"). [***] The Cargo Deliver or Pay Quantity multiplied by the Cargo Deliver or Pay Price shall be the "**Cargo Deliver or Pay Obligation**". [***]

7.6.1(X) The [***] period after the end of the Permitted Time in Clause 7.6.1(2) shall become [***] hours on and after the Future Facilities Commercial Operations Date.

7.6.1(Y) [***]

7.6.2 The Parties hereby acknowledge and agree that the Cargo Deliver or Pay Obligation shall be in the nature of damages and shall be the Buyer's sole and exclusive remedies in damages or otherwise for failure by the Seller Group to make available such Cargo and represents a proportionate protection of the legitimate interests of the Buyer in connection with the applicable Cargo Deliver or Pay Quantity.

7.6.3 Subject to Clauses 7.6.4 and 7.6.5, the Seller Group’s liability to pay a Cargo Deliver or Pay Obligation to the Buyer shall be satisfied by the application by the Seller Group of a credit (a "**Cargo Deliver or Pay Credit**") to the Buyer, in an amount equal to such Cargo Deliver or Pay Obligation, in the first invoice issued by the Seller Group to the Buyer in accordance with Clause 12.1.1 after the expiration of [***] from the date of receipt of the Buyer’s invoice, and subject always to the provisions of Clause 12.3.2.

7.6.4 [***]

7.6.5 [***]

7.7 **[***]**

7.7.1 [***]

7.7.2 [***]

7.7.3 [***]

7.7.4 [***]

(A) [***]

(B) [***]

7.7.5 [***]

7.8 Quarterly and Annual Statements

7.8.1 No later than thirty (30) days after the end of each of the first three (3) Calendar Quarters within a given Contract Year (if applicable), the Seller Group shall provide to the Buyer a quarterly statement which includes the information described in Clause 7.8.3 for such Calendar Quarter (a **"Quarterly Statement"**).

7.8.2 No later than thirty (30) days after the last Calendar Quarter within a given Contract Year, the Seller Group shall generate a statement, which shall aggregate all of the information included in the Quarterly Statements applicable to such Contract Year in addition to the information described in Clause 7.8.3 arising in such final Calendar Quarter (an **"Annual Statement"**).

7.8.3 Each Quarterly Statement and the Annual Statement for a given Contract Year shall include the following information (all quantities expressed in MMBtu except where otherwise indicated):

(A) the AACQ for such Contract Year separated into each of its components pursuant to Clause 7.2;

(B) until the Future Facilities Commercial Operations Date, the total amount of any In Year Surplus Quantities arising during such Calendar Quarter or Contract Year, as applicable;

(C) until the Future Facilities Commercial Operations Date, the total quantities of LNG produced by the FLNG Facility (in cubic metres and in MMBtu) during each day of such Calendar Quarter or Contract Year (net of any losses at the FLNG Facility);

(D) the total quantities of LNG delivered to the Buyer during such Calendar Quarter or Contract Year, as applicable;

(E) the total amount of any Cargo Take or Pay Quantities arising during such Calendar Quarter or Contract Year, as applicable;

(F) the total amount of any Make-Up Quantities delivered during such Calendar Quarter or Contract Year, as applicable;

(G) the total amount of any Cargo Deliver or Pay Quantities arising during such Calendar Quarter or Contract Year, as applicable;

(H) any additional information that the Parties may agree is necessary for the efficient operation of this Agreement.

7.9 Operational Tolerance

For each Cargo there shall be an operational tolerance of up to plus [***] or minus [***] of the Scheduled Loading Quantity (the “**Operational Tolerance**”). The provisions of Clauses 7.4 and 7.6 shall not apply to any Cargo if the Quantity Delivered for that Cargo is at least [***] of the Scheduled Loading Quantity. If the Quantity Delivered is less than [***] of the Scheduled Loading Quantity for a Cargo, the Scheduled Loading Quantity (excluding the Operational Tolerance) shall be used for the purpose of calculating amounts due in accordance with the provisions of Clauses 7.4 or 7.6, as applicable. For the avoidance of doubt, the Parties shall seek in good faith to deliver and take the Scheduled Loading Quantity for each Cargo (without any adjustment in respect of the Operational Tolerance) and the Operational Tolerance shall apply only in the manner described above in this Clause 7.9 and shall not be assumed or implied as reducing/increasing the Buyer’s obligations under Clause 7.4 or the Seller Group’s obligations under Clause 7.6.

8. DELIVERY POINT, TITLE AND RISK

8.1 Delivery Point

Each Cargo of LNG to be sold by the Seller Group and purchased by the Buyer pursuant to this Agreement shall be made available to Buyer at the junction point at which the flange coupling of the loading lines at the LNG Hub Facilities (or such other Loading Terminal pursuant to Clause 2.2.4) join the flange coupling of the loading manifold of the Approved LNG Ship (the **"Delivery Point"**).

8.2 Title, Risk and Claims

8.2.1 Title to and all risks (including risk of loss) in respect of the LNG delivered hereunder shall pass from the Seller Group to the Buyer at the Delivery Point; and

8.2.2 Title to and all risks (including risk of loss) in respect of Natural Gas vapour returned from an Approved LNG Ship during the loading operation will pass from the Buyer to the Seller Group as it passes the point at which the outlet flange of the vapour return line (or vapour return line spool piece, if used) of the Approved LNG Ship connects with the inlet flange of the vapour return line of LNG Hub Facilities (or such other Loading Terminal pursuant to Clause 2.2.4).

8.3 The Parties agree that if a Party, acting reasonably, determines that it is necessary due to regulatory or taxation risks, or to a change in any applicable law, regulation, rule, decree or official government order relating to the imposition of taxes, charges, royalties, duties or other imposts whatsoever levied by a Competent Authority in Mauritania and/or Senegal, to re-examine the location where title is transferred to the Buyer, then the Parties will immediately consult and, provided that a change would not impose material risks, liabilities or costs on any of the other Parties, negotiate in good faith to make any mutually acceptable amendments to this Clause 8. It is understood that no Party is obligated to agree to any amendments to this Agreement.

8.4 Title Warranty

Each Seller warrants (as a continuing warranty repeated each time LNG is sold and delivered under this Agreement) to the Buyer that at the point of title transfer it has good title to its LNG SPA Participation share of LNG sold and delivered under this Agreement, and such LNG will at the point of title transfer be transferred to the Buyer free and clear from any encumbrances.

8.5 Each Seller shall indemnify, defend and hold harmless Buyer from and against any direct loss, liability, damage or expenses or claims [***] incurred by or made against Buyer in consequence of any breach by such Seller of the warranty of title in Clause 8.4.

9. TRANSPORTATION AND LOADING

9.1 Transportation by Buyer

9.1.1 The Buyer shall, at no expense to the Seller Group, be responsible for the transportation from the Delivery Point of all quantities of LNG to be sold and purchased under this Agreement. All Approved LNG Ships shall, in the course of being used by the Buyer to fulfil its obligations for the receipt and transportation of LNG under this Agreement, comply with the provisions of this Agreement, applicable Laws and International Standards.

9.1.2 The Buyer shall pay or cause to be paid Port Charges directly to the Seller Group (or the appropriate Person nominated by the Seller Group) or to any Competent Authority (if applicable) [***], the Seller Group shall ensure that (i) any Port Charges which are initially incurred by the Seller Group, a Seller or the LNG Hub Facilities Operator, shall be charged to Buyer on cost pass-through basis per Cargo, and (ii) Port Charges shall be applied on a non-discriminatory basis that does not favour any other off-taker over the Buyer. The Buyer may furnish the Seller Group with an invoice, together with relevant supporting documents showing the basis for the calculation, in accordance with Clause 12.1.3 in relation to such incremental Port Charges. The Seller Group shall have the right to cause a Third Party auditor to verify any invoices issued in relation to or any amounts described in this Clause 9.1.2 in accordance with Clause 19.3.

9.2 **Facilities Manuals and Conditions of Use**

9.2.1 The Parties acknowledge the Conditions of Use shall initially be as attached hereto as Schedule 8. As soon as reasonably practicable after the Effective Date, the LNG Hub Facilities Operator shall develop the Facilities Manuals which shall in any event be in English and in accordance with International Standards and standards of a Reasonable and Prudent Operator applicable to such facilities and shall meet the Conditions of Use Requirements. [***]

9.2.2 [***]

9.2.3 In the event of a conflict between this Agreement and the Facilities Manuals and Conditions of Use, the provisions of this Agreement shall prevail.

9.2.4 The Seller Group and the Buyer agree that the Facilities Manuals and the Conditions of Use shall at all times be such as to ensure the operational safety of the LNG Hub Facilities and the Approved LNG Ships.

9.2.5 The Buyer (i) shall cause any Transporter and/or the master of any Approved LNG Ship to sign the Conditions of Use before using the LNG Hub facilities and (ii) shall cause the Transporters and Approved LNG Ships to comply with the Facilities Manuals and the Conditions of Use.

9.2.5(A) The Facilities Manuals and the Conditions of Use must satisfy the following:

(A) do not require any Person to act or to fail to act in any manner which is prohibited or penalised under any applicable law;

(B) do not impose liabilities on the Transporter and/or the Approved LNG Ships which are not insured under the standard terms of P&I cover offered by P&I Clubs in the International Group of P&I Clubs other than in respect of liabilities arising in respect of loss or damage to the Approved LNG Ship;

(C) do not negatively impact the Buyer's ability to perform its obligations or exercise its rights under this Agreement; and

(D) [***],

the “**Conditions of Use Requirements**”.

The Parties agree that the Conditions of Use attached as Schedule 8 meet the Conditions of Use Requirements as of the Effective Date.

9.2.5(X)[***]

9.2.6 The Seller Group may amend from time to time the Facilities Manuals and the Conditions of Use without the prior approval of the Buyer, but only if such amendments satisfy the Conditions of Use Requirements and the requirements in Clause 9.2.1. The Seller Group shall promptly notify Buyer of any proposed amendments to the Facilities Manuals and/or the Conditions of Use and shall provide a copy of such amendments to the Buyer in

English. At the request of either Party, the Parties shall convene a meeting of the Marine Working Group to discuss any such amendments.

9.2.7 If at the time of delivery of a Cargo under this Agreement, the Facilities Manuals and/or Conditions of Use have been changed and such changes are inconsistent with the Conditions of Use Requirements and the requirements in Clause 9.2.1 and the Buyer has not consented to the change, the Transporter and/or master of any Approved LNG Ship shall not be required to sign or otherwise to be bound by the terms of such amended documents, but rather shall be required to sign and be bound by the terms of the Facilities Manual and/or Conditions of Use as they existed prior to the amendment which is inconsistent with the Conditions of Use Requirements and the requirements in Clause 9.2.1.

9.3 **Approved LNG Ships**

9.3.1 The Buyer shall, at no expense to the Seller Group, at all times throughout the Contract Term, cause each Approved LNG Ship, whilst being utilized by Buyer for the performance to fulfil its obligations hereunder to be provided, maintained, repaired and operated in compliance with the provisions of this Agreement, applicable Laws and International Standards. Without prejudice to the aforesaid, the Seller Group and the Buyer shall discuss in good faith any issues relating to the Approved LNG Ship Conditions, compatibility of the Approved LNG Ships and the LNG Hub Facilities. The Buyer may nominate (i) any Approved LNG Ship for the lifting of LNG under this Agreement, or (ii) any Proposed LNG Ship, subject to the Seller Group’s approval of the vessel as an Approved LNG Ship in accordance with this Clause 9.3 prior to the Arrival Window of an applicable Cargo.

9.3.2 Prior to becoming an Approved LNG Ship, all LNG Ships proposed to be used by the Buyer for the receipt and transportation of LNG under this Agreement must first be approved by the Seller Group (such approval not to be unreasonably withheld or delayed) in accordance with this Clause 9.3, and must at all times, while being used by the Buyer for the performance of its obligations hereunder, be compatible in all material respects with the LNG Hub Facilities and in compliance with the requirements of Clause 9.3.13 (together the **"Approved LNG Ship Conditions"**).

9.3.3 The Seller Group acknowledges that as of the Effective Date, the Approved LNG Ships listed in Schedule 2 meet the Approved LNG Ship Conditions and as such, have been pre-approved by the Seller Group for the Buyer's use for the transportation of LNG under this Agreement. Schedule 2 shall be updated from time to time to reflect the addition of any Proposed LNG Ship that has become an Approved LNG Ship and/or the removal of any Approved LNG Ship that no longer complies with the Approved LNG Ship Conditions.

9.3.4 The Buyer may from time to time, propose additional LNG ships to be included in Schedule 2 as an Approved LNG Ship ("**Proposed LNG Ship**") by notifying the Seller Group.

9.3.5 Until the end of the Contract Term, the Seller Group and the Buyer shall work together to allow Proposed LNG Ships to become Approved LNG Ships, provided that the inclusion of any Proposed LNG Ship in Schedule 2 as an Approved LNG Ship shall be subject to the Seller Group's approval, such approval not to be unreasonably withheld or delayed and to be provided if the Approved LNG Ship Conditions are met. The Seller Group may carry out an inspection of a Proposed LNG Ship under Clause 9.3.6 (B) if such inspection is necessary for completing such checks.

9.3.6 The Buyer shall provide, or procure the provision of, in respect of any Proposed LNG Ship:

(A) such information as is reasonably required for the Seller Group to determine whether such Proposed LNG Ship meets the Approved LNG Ship Conditions. The Seller Group may disclose such information to its representatives, including an independent internationally recognised and suitably qualified maritime consultant, and the LNG Hub Facilities Operator; and

(B) the Seller Group may, on reasonable prior notice to the Buyer, carry out a SIRE inspection of the Proposed LNG Ship, acting as a Reasonable and Prudent Operator, if it determines that a SIRE inspection is necessary. Such inspection may be carried out by representatives of the Seller Group (which may include an independent internationally recognised and suitably qualified maritime consultant) or the LNG Hub Facilities Operator and shall be carried out in accordance with internationally accepted standards for such inspections and by suitably qualified (SIRE accredited) personnel. [***] Any personnel, agents, representatives and consultants of Seller Group attending such inspection shall:

(1) comply with all HSSE requirements of the Buyer, Transporter (or the shipyard, if applicable) which apply to all other Persons conducting similar inspections and apply on a non-discriminatory basis; and

(2) do so at the Seller Group's cost and risk,

provided that such inspection rights shall not entitle the Seller Group, the LNG Hub Facilities Operator or their representatives to make any request or recommendation directly to the Buyer or the Transporter and shall be limited to reviewing compliance by the Proposed LNG ship with the Approved LNG Ship Conditions, provided that neither the exercise nor the non-exercise of such rights shall reduce the responsibility of the Buyer to the Seller Group in respect of such Proposed LNG ship and its operation, nor increase the Seller Group's responsibility to Buyer or any Third Party for the same.

9.3.7 Upon the Buyer nominating a Proposed LNG Ship, the Buyer and the Seller Group shall use reasonable endeavours to procure the SIRE inspection, if such inspection is determined by Seller Group to be necessary in accordance with Clause 9.3.6, and approval of the Proposed LNG Ship as expeditiously as reasonably practicable and the Seller Group shall not unreasonably withhold or delay its approval of such Proposed LNG Ship pursuant to Clause 9.3.5, and in any event the Seller Group shall notify the Buyer as to whether it approves or rejects such Proposed LNG Ship as soon as reasonably practical and in any event no later than [***] days following such proposal by the Buyer under Clause 9.3.4. A Proposed LNG Ship which is approved by the Seller Group shall be an Approved LNG Ship and Schedule 2 shall be amended accordingly.

9.3.8 If the Seller Group rejects a Proposed LNG Ship, the Seller Group shall specify in its notice the detailed reasons for withholding approval and identifying areas of material non-compliance with the Approved LNG Ship Conditions, and promptly thereafter the Parties shall discuss any such failure of the Proposed LNG Ship to meet the Approved LNG Ship Conditions and cooperate to develop an agreed action plan for the Buyer to rectify the concern(s).

9.3.9 If the Seller Group has reasonable grounds to believe or (acting reasonably) determines that any Approved LNG Ship named to receive a Commissioning Cargo, or named in the Annual Delivery Programme or a Specific Delivery Schedule does not meet the requirements of this Agreement, the Seller Group shall promptly notify the Buyer and shall specify the basis and detailed reasons for such non-compliance. Promptly after the Seller Group provides such notice, the Parties shall consult and co-operate with a view to agreeing a course of action that addresses such concerns and permits the performance of Buyer's obligations under this Agreement, including the provisions of Clause 9.3.13. The Seller Group may elect to seek information pursuant to Clause 9.3.6(A) and may, if it deems necessary, acting as a Reasonable and Prudent Operator, elect to conduct an inspection of the Approved LNG Ship in the manner and within scope set forth in Clause 9.3.6 (B) (except that the inspection shall be to review the potential non-compliance rather than a SIRE inspection [***] Notwithstanding the above, if the Seller Group (acting reasonably) determines that such Approved LNG Ship is in material non-compliance with the provisions of Clause 9.3 of this Agreement, the Seller Group shall have the right to reject such LNG Ship by notifying the Buyer and giving detailed reasons for such determination. Such LNG Ship shall cease to be an Approved LNG Ship and the Buyer may not use such LNG ship under this Agreement until such time as the material non-compliance has been rectified and the LNG Ship has again been approved by the Seller Group as an Approved LNG Ship. The Buyer's obligations under this Agreement and its liability for any delay or failure in performance thereof shall not be excused or suspended by reason of the Seller Group's rejection and the Buyer's inability pursuant to the terms of this Clause 9.3 to use such LNG Ship as an Approved LNG Ship.

No inspection of an Approved LNG Ship shall (i) modify or amend the Buyer's obligations, representations, warranties and covenants under this Agreement, or (ii) constitute an acceptance or waiver by the Seller Group of the Buyer's obligations hereunder.

9.3.10 The Buyer shall refrain from modifying any Approved LNG Ship to be used by the Buyer for the transportation of LNG under this Agreement in any manner whatsoever that would render it incompatible with the LNG Hub Facilities unless such modification is required in order to ensure continued compliance with the foregoing provisions of this Clause 9.3; provided however that:

(A) an Approved LNG Ship may be modified pursuant to a change in International Standards or any Law with which the Approved LNG Ship is required to comply, in which case such modification necessary for the Approved LNG Ship shall be paid for by the Buyer and the Buyer shall promptly notify the Seller Group of any such required modification, provided further that any modification of an Approved LNG Ship pursuant [***];

(B) any reasonable modification of the FLNG Facility or the LNG Hub Facilities that the Seller Group determines to be required in consequence of a modification to an Approved LNG Ship contemplated in Clause 9.3.10(A), [***]; provided that the Seller Group shall not be required to make such modification if the result of such modification would limit the ability of the FLNG Facility or the LNG Hub Facilities to produce or deliver LNG to other buyers or conflict with this Agreement, applicable Law or Authorizations. If the FLNG Facility or the LNG Hub Facilities are not modified to maintain the necessary compatibility with an Approved LNG Ship that is modified pursuant to Clause 9.3.10(A), such circumstances shall be deemed to be Seller's Force Majeure, and neither Party will be in breach of its obligations to deliver or take LNG, or be liable for any delay or failure in performance thereof, under this Agreement subject to Clause 16.7; and

(C) any other modifications to an Approved LNG Ship shall be subject to the prior consent of Seller Group which shall not be unreasonably withheld or delayed, provided that the Buyer shall reimburse the Seller Group for all reasonable costs and losses incurred by the Seller Group in modifying the FLNG Facility or the LNG Hub Facilities to maintain compatibility with the Approved LNG Ship.

9.3.11 If modifications to an Approved LNG Ship are required to maintain compliance with changes with International Standards or Laws pursuant to Clause 9.3.10(A), the Parties shall discuss as soon as reasonably practicable what steps should be taken in order to minimise the impact of such changes on the Parties' abilities to perform this Agreement. If, as a result of such requirements and following such discussions, the Parties are unable to perform their obligations under this Agreement, provided the requirements of Clause 16 are met, such circumstances shall be deemed to be Buyer's Force Majeure subject to Clause 16.7.

9.3.12 The Buyer shall have the right, in its sole discretion, to remove any LNG Ship as an Approved LNG Ship under this Agreement at any time, provided that such right shall not lessen the Buyer's obligations under Clause 9.1.1.

9.3.13 Without prejudice to Clause 9.3.1, Buyer shall ensure that each Approved LNG Ship shall be:

(A) designed, equipped and manned so as to safely and reliably permit the loading of a Cargo at a bulk transfer rate of at least ten thousand cubic metres (10,000m^3) per hour using at least 2 x 12" loading arms;

(B) have a gross cargo containment capacity not less than one hundred and twenty-five thousand cubic metres (125,000m^3) and not exceeding one hundred and eighty thousand cubic metres (180,000m^3);

(C) constructed (if applicable), operated and maintained in compliance with:

(1) all applicable Laws of flag state, coastal states and port states where the Approved LNG Ship will dock or call (collectively the "**LNG Ship International Conventions, Rules and Regulations**");

(2) rules of classification societies belonging to the International Association of Classification Societies ("**IACS**");

(3) the applicable provisions contained in the latest edition of the publications:

(a) "International Safety Guide for Oil Tankers and Terminals" (ISGOTT) by ICS/OCIMF/IAPH; and/or

(b) "Tanker Safety Guide for Liquefied Gas" by the ICS;

(4) all applicable International Standards (including the International Code for the Construction and Equipment of Ships Carrying Liquified Gases in Bulk the IGC code); recommendations and guidelines published by SIGTTO, OCIMF, GIIGNL, PIANC;

(D) provided with all documents and certificates, up to date and valid, required by LNG Ship International Conventions, Rules and Regulations and by the relevant classification society;

(E) the subject of an available tanker management and self-assessment report in the OCIMF database, updated within the last twelve (12) months, provided that (i) the absence of such report shall not constitute grounds for the Seller Group to reject an LNG ship as an Approved LNG Ship if the SIRE requirements under this Clause 9.3.13 are met; and (ii) the Buyer and the Seller Group shall conduct a risk assessment (each acting as a Reasonable and Prudent Operator) to assess the risks associated with the use of such relevant LNG Ship under this Agreement;

(F) not more than [***] years of age;

(G) furnished with a condition assessment programme certificate at the beginning of their twentieth (20th) year of age, which shall be considered valid for a period of three (3) years from the issuance date and must meet the following requirements:

(1) a rating of 1 or 2 regarding hull, machinery and cargo system; and

(2) be issued by a classification society belonging to the IACS;

provided that, for LNG Ships with a double class agreement, a condition assessment programme certificate issued by the secondary class shall be acceptable;

(H) entered for insurance with a member that has full entry in the International Group of P&I Clubs including pollution liability standard, and hull and machinery coverage from a reputable insurance underwriter, save where the Approved LNG Ship is owned or operated by Buyer or any of its Affiliates, in which case hull and machinery may be self-insured by its owner or operator, in each case with such cover and in such an amount as would be obtained by a Reasonable and Prudent Operator of LNG ships on vessels of its type;

(I) operated in accordance with International Standards specified in Clause 9.3.13(C)(4) by skilled and competent operators, officers and crew who (a) are suitably qualified, trained and experienced in international LNG or oil tanker operations and qualified to a minimum of International Maritime Organisation standards and (b) can communicate with regulatory authorities and operators at the loading terminal in written and spoken English;

(J) without prejudice to the generality of the above, operated so as to discharge ballast water in accordance with the IMO International Convention for the Control and Management of Ships' Ballast Water and Sediments (BWM);

(K) manned with a qualified and competent crew including, without limitation, the master, senior officers and personnel responsible for cargo handling operations who are experienced in LNG vessel operations in compliance with the SIGTTO LNG and LNG Experience Matrix; and

(L) the subject of an entry in the OCIMF's Ship Inspection and Report Programme (SIRE) with an inspection report which is no older than twelve (12) months at any given time and which demonstrates that there are no material deficiencies in the safety or operability of the LNG ship where such ship is up to ten (10) years old;

(M) the subject of an entry in the OCIMF's Ship Inspection and Report Programme (SIRE) with an inspection report which is no older than six (6) months at any given time and which demonstrates that there are no material deficiencies in the safety or operability of the LNG ship where such ship is more than ten (10) years old;

(N) provided with a completed new build questionnaire (in the case of a new build LNG ship);

(O) equipped with appropriate systems for communication with the loading terminal;

(P) equipped with appropriate systems necessary for email, telephone and radio communications with the loading terminal;

(Q) equipped with appropriate systems for receiving and transmission of emergency shutdown signals;

(R) equipped with adequate facilities for mooring, unmooring and handling LNG at the delivery point in accordance with the recommendations of OCIMF and SIGTTO;

(S) have discharge and emission levels within MARPOL guidelines; and

(T) (i) fit in every way for the safe loading, unloading, handling and carrying of LNG in bulk at atmospheric pressure, and (ii) tight, staunch, strong and otherwise seaworthy with cargo handling and storage systems (including instrumentation) necessary for the safe loading, unloading, handling, carrying and measuring of LNG in good order and condition.

9.3.14 The provisions of this Agreement regarding the Approved LNG Ships shall apply whether or not such Approved LNG Ship is owned, operated and/or contracted by the Buyer.

9.4 **Seller Group's Facilities**

9.4.1 The Seller Group shall, at no expense to the Buyer, at all times throughout the Contract Term, provide, maintain, repair and operate (or cause to be provided, maintained, repaired and operated) the Seller Group's Facilities in good working order and in a safe and efficient manner so as to (i) meet all applicable Laws and International Standards, including, where applicable the regulations of the flag state, the Laws of each of Mauritania and Senegal, and the rules of a classification society that is a member of the International Association of Classification Societies, as such Laws, International Standards, rules and regulations may be amended or modified from time to time, and (ii) comply with the provisions of this Agreement.

9.4.2 The Seller Group shall design and construct or cause to be designed and constructed the FLNG Facilities and LNG Hub Facilities to be compatible with each Approved LNG Ship listed in Schedule 2 as of the Effective Date, based on the technical information provided by the Buyer on or before the Effective Date.

9.4.3 If an Approved LNG Ship listed in Schedule 2 as of the Effective Date is unable to load a Cargo because the Seller Group is in breach of its obligations in Clause 9.4.2 with respect to such Approved LNG Ship, then;

(A) the Buyer shall be deemed to have fulfilled its' obligations to take the Cargo; and

(B) the Seller Group shall be deemed to have failed to make available such Cargo.

9.4.4 The Seller Group shall cause the Seller Group's Facilities to be of appropriate design and sufficient capacity to enable the Seller Group to perform its obligations to make available the quantities of LNG in accordance with the terms of this Agreement and shall include, without limitation, the following:

(A) safe marine berth facilities that comply with OCIMF, PIANC and SIGTTO guidelines and other International Standards, and are capable of safely receiving and accommodating an Approved LNG Ship (whether partially loaded or not) having a gross capacity of between one hundred and twenty five thousand cubic metres (125,000m^3) and one hundred and eighty thousand cubic metres (180,000 m^3), and which the Approved LNG Ship can safely reach and from which it can safely depart, fully laden (or partially loaded), and at which the Approved LNG Ship can lie safely berthed and load safely afloat at all times, and, subject to the provisions of this Clause 9.4, such facilities shall be deemed to be part of the LNG Hub Facilities;

(B) loading facilities capable of safely and reliably loading a Cargo at an approximate rate of [***] pressure using a minimum of two (2) liquid loading arms (or such other number of such arms and such pressure as may be agreed between the Buyer and the Seller Group) at the Delivery Point, provided that from the Future Facilities Commercial Operations Date, the loading facilities shall be capable of safely and reliably loading a Cargo at an [***] pressure using a minimum of two (2) liquid loading arms (or such other number of such arms and such pressure as may be agreed between the Buyer and the Seller Group);

(C) a vapour return system capable of receiving Natural Gas from the Approved LNG Ship at the rate required for the loading of LNG at the rate specified in Clause 9.4.4(B) and in the event of a cool-down operation;

(D) appropriate systems for necessary email, facsimile, telephone and radio communications with the Approved LNG Ship;

(E) qualified and competent personnel, fluent in spoken and written English, to coordinate with the Approved LNG Ship during loading operations;

(F) tanks and loading lines for liquid or gaseous nitrogen adequate to purge the loading lines;

(G) emergency shutdown systems capable of interfacing with emergency shut down systems on board the Approved LNG Ship;

(H) mooring and fendering arrangements and equipment designed, constructed and maintained in accordance with OCIMF and other international standards;

(I) port security arrangements in accordance with International Ship and Port Security Code (ISPS Code);

(J) firefighting arrangements and equipment in accordance with relevant national and international fire safety standards;

(K) an FLNG Facility designed, constructed, operated and maintained in accordance with (i) all applicable Laws of flag state, and the laws of Mauritania and Senegal; (ii) all applicable rules of classification societies belonging to the International Association of Classification Societies ("**IACS**"); and (iii) all applicable International Standards (including the International Code for the Construction and Equipment of Ships Carrying Liquified Gases in Bulk – the IGC code); recommendations and guidelines published by SIGTTO, OCIMF, GIIGNL;

(L) an FLNG Facility provided with all documents and certificates, up to date and valid, required by International Conventions, Rules and Regulations and by the relevant classification society;

(M) an FLNG Facility that is (i) fit in every way for the safe loading, unloading, handling and carrying of LNG in bulk at atmospheric pressure, and (ii) tight, staunch and strong, with cargo handling and storage systems (including instrumentation) necessary for the safe loading, unloading, handling, storage and measuring of LNG in good order and condition; and

(N) an FLNG Facility that is designed and built to withstand the metocean conditions at their location.

9.4.5 The Seller Group shall refrain from modifying the FLNG Facility or the LNG Hub Facilities in any manner whatsoever that would render them incompatible with the Approved LNG

Ships unless such modification is a part of Future Facilities Implementation Works or is required in order to ensure continued compliance with the foregoing provisions of this Clause 9.4, provided however that:

(A) the FLNG Facility or the LNG Hub Facilities may be modified pursuant to Future Facilities Implementation Works or a change in International Standards or any Law with which FLNG Facility or the LNG Hub Facilities are required to comply, in which case such modifications shall be paid for by the Sellers and the Seller Group's Representative shall promptly notify the Buyer of any such required modification;

(B) any reasonable modification of the Approved LNG Ships that the Buyer determines to be required in consequence of any modification to the FLNG Facility or the LNG Hub Facilities contemplated in Clause 9.4.5(A) to maintain compatibility with the FLNG Facility or the LNG Hub Facilities, shall be paid for by the Buyer [***], and (ii) any modification of an Approved LNG Ship pursuant to this Clause 9.4.5(B) that is made by Buyer, that is required as a result of Future Facilities Implementation Works [***]. If the Approved LNG Ships are not modified to maintain the necessary compatibility with the FLNG Facility or the LNG Hub Facilities as provided above, and the modification of the FLNG Facility or LNG Hub Facilities was pursuant to:

(i) a change in International Standards or any change in Law, such circumstances shall be deemed to be Buyer’s Force Majeure and neither Party will be in breach of its obligations to deliver or take LNG or liable for any delay or failure in performance thereof subject to Clause 16.7; or

(ii) Future Facilities Implementation Works, then Buyer shall be relieved of its obligations to take LNG and the Seller Group shall be deemed to have failed to make LNG available; and

(C) any other modifications to the FLNG Facility or the LNG Hub Facilities that would render them incompatible with the Approved LNG Ships shall be subject to the prior consent of the Buyer which shall not be unreasonably withheld, and the Seller Group shall reimburse the Buyer for all costs and losses reasonably incurred by the Buyer in modifying any Approved LNG Ships to maintain compatibility with the FLNG Facility or the LNG Hub Facilities.

9.4.6 If modifications to the FLNG Facility or the LNG Hub Facilities are required to maintain compliance with changes with International Standards or Laws pursuant to Clause 9.4.5(A), the Parties shall discuss as soon as reasonably practicable what steps should be taken to minimise the impact of such changes on the Parties’ abilities to perform their obligations under this Agreement. If, as a result of such requirements and following such discussions, the Parties are unable to perform their obligations under this Agreement, provided that the requirements of Clause 16 are met, such circumstances shall be deemed to be the Seller’s Force Majeure, subject to Clause 16.7.

9.4.7 Without prejudice to 9.4.5, the Seller Group shall promptly notify the Buyer if Future Facilities Implementation Works are likely to render the FLNG Facility or the LNG Hub Facilities incompatible with the Approved LNG Ships. Such matters shall be discussed by the Marine Working Group and the Seller Group shall take reasonable steps to minimise activities that would result in incompatibility with the Approved LNG Ships.

9.4.8 From the Effective Date, upon request from the Buyer, the Seller Group shall provide the Buyer or its Representatives information pertaining to the FLNG Facility or the LNG Hub Facilities (including operational and safety procedures) that is reasonably required and requested by the Buyer in order for it to review and verify compliance with the requirements of this Agreement at any time from the Effective Date, and the Buyer may, upon giving reasonable prior notice to the Seller Group, carry out an inspection of the FLNG Facility or the LNG Hub Facilities. Such inspection may be carried out by a reasonable number of the Buyer's Representatives. Any such inspection of the FLNG Facility or the LNG Hub Facilities shall be conducted at the Buyer's sole cost and risk. The Buyer will conduct such inspection and examination in a manner that complies with all onsite HSSE requirements, and minimises the impact on the operations of the FLNG Facility or the LNG Hub Facilities. The Buyer's right to inspect and examine the FLNG Facility and the LNG Hub Facilities shall be limited to verifying the Seller Group's compliance with its obligations under this Agreement. No obligation of the Seller Group under this Agreement shall be diminished, waived or in any way affected by reason of any such inspection by or on behalf of the Buyer or by any requests or observations made by the Buyer in connection with any such inspection. Neither the exercise nor the non-exercise of such rights shall reduce the responsibility of the Seller Group to the Buyer in respect of the Seller Group's Facilities and their operation, nor increase the Buyer's responsibility to the Seller Group or any Third Party for the same.

9.4.9 If the Buyer has reasonable grounds to believe or (acting reasonably) determines that the FLNG Facility or the LNG Hub Facilities do not meet the requirements of this Agreement, the Buyer shall promptly notify the Seller Group and shall specify the basis and detailed reasons for such non-compliance. Promptly after the Buyer provides such notice, the Parties shall consult and co-operate with a view to agreeing a course of action that addresses the Buyer's concerns and permits the performance of the Seller Groups' obligations under this Agreement, including the provisions of Clause 9.4.4. The Buyer may elect to seek information pursuant to 9.4.8 and may, if it deems necessary, acting as a Reasonable and Prudent Operator, elect to conduct an inspection of the FLNG Facility or the LNG Hub Facilities in accordance with Clause 9.4.8. [***]. It is recognised that a scheduled Approved LNG Ship may be impacted by the material non-compliance of the FLNG Facility or the LNG Hub Facilities with the provisions of Clause 9.4 notwithstanding that such Approved LNG Ship is compatible with such facilities (for example, if the material non-compliance is the failure to provide safe marine berth facilities). The Seller Group's obligations under this Agreement and its liability for any delay or failure in performance thereof shall not be excused or suspended by reason of the Buyer's notification of rejection, and the Seller Group shall be deemed to have failed to make available LNG to the Buyer from the LNG Hub Facilities.

No inspection of an the FLNG Facility and/or the LNG Hub Facilities shall (i) modify or amend the Seller Groups' obligations, representations, warranties and covenants under this Agreement, or (ii) constitute an acceptance or waiver by the Buyer of the Seller Groups' obligations hereunder.

9.4.10 The Parties acknowledge the mutual benefit of avoiding situations of rejection [***] under this Agreement, and without prejudice to such rights under Clauses 9.3.7, 9.3.9, 9.4.9 and 9.5.4, shall co-operate in good faith [***] including use of the Marine Working Group to facilitate safe and reliable operations.

9.5 Marine Services

9.5.1 The Seller Group shall procure the provision of all Marine Services necessary for the safe approach from the Pilot Boarding Station, berthing, mooring, loading, unberthing and safe departure to the Pilot Boarding Station of an Approved LNG Ship in compliance with the terms of this Clause 9.5.

9.5.2 The Buyer acknowledges that the following services and facilities are not provided nor procured by the Seller Group: (a) facilities and loading lines for liquid or gaseous nitrogen to purge an LNG ship tanks except where nitrogen is required for draining and purging of the liquid and vapour lines prior to disconnection of loading arms; (b) facilities for providing bunkers; (c) facilities for the handling and delivery to the LNG ship of ship's stores, provisions and spare parts.

9.5.3 The Seller Group shall ensure that:

(A) adequately well trained and experienced pilots and mooring masters in sufficient numbers are available at all times in order to assure the safe and reliable berthing, unberthing and transit to and from the berth as part of the provision of Marine Services under Clause 9.5.1;

(B) fit for purpose harbour or offshore tugs of adequate design and power are available at all time in sufficient numbers in order to assure the safe and reliable berthing, unberthing and transit to and from the berth as part of the provision of Marine Services under Clause 9.5.1;

(C) adequately well trained and experienced tug masters in sufficient numbers are available at all times to operate the harbour or offshore tugs;

(D) fit for purpose marine support craft (including pilot vessels, mooring boats and service/security boats) in sufficient numbers are available at all times in order to support intended marine operations as part of the facilitation of Marine Services under Clause 9.5.1;

(E) fit for purpose metocean measuring and monitoring systems and navaids and associated marine support infrastructure is available to support safe and reliable marine operations as part of the facilitation of Marine Services under Clause 9.5.1.

9.5.4 [***]

9.6 Authorisations

9.6.1 The Seller Group shall, at no cost to the Buyer, be responsible for obtaining and maintaining the Seller Group's Consents and all customary approvals, permissions, marine permits and other technical and operational Authorisations required for the FLNG Facility, the LNG Hub Facilities and the Future Facilities. The Buyer shall, at the Seller Group's request, co-operate with and assist the Seller Group in obtaining such approvals, permits and Authorisations.

9.6.2 The Buyer shall, at no cost to the Seller Group, be responsible for obtaining and maintaining the Buyer's Consents and all customary approvals, permissions, marine permits and other technical and operational Authorisations (including, for the avoidance of doubt, all necessary clearances) required for the use by any Approved LNG Ship of the FLNG Facility or the LNG Hub Facilities (“**Marine Authorisations**”). The Seller Group shall, at the Buyer's request, at Buyer’s expense, co-operate with and assist the Buyer in obtaining such approvals, permits and Authorisations.

9.6.3 Seller Group shall obtain, or cause to be obtained, any licence or other official Authorisation it may require and carry out all customs formalities necessary for the Export of the LNG hereunder (in each case save to the extent the Buyer is required to obtain any such licence or Authorisation or carry out such formalities pursuant to Clause 9.6.2).

9.6.4 Buyer and Seller Group shall obtain and maintain in force all Authorisations, approvals and permissions of all Competent Authorities that are required for the performance of this Agreement, and shall co-operate fully with each other wherever necessary for this purpose.

9.7 **Notice of Estimated Time of Arrival at Facilities**

9.7.1 As soon as reasonably practicable after departure of the relevant Approved LNG Ship from its last port of call prior to arriving at the LNG Hub Facilities, the Buyer shall, or cause the master of the Approved LNG Ship to, give notice to the Seller Group and/or the LNG Hub Facilities Operator by email of its estimated date and time of arrival at the Pilot Boarding Station (**"Estimated Time of Arrival"** or **"ETA"**). The Buyer shall also include the following information in such notice to the Seller Group and/or the LNG Hub Facilities Operator:

(A) the Approved LNG Ship's name;

(B) any operational deficiencies in the Approved LNG Ship that may affect its performance at the LNG Hub Facilities;

(C) the estimated tank pressure, heel quantity and heel temperature on arrival at the Loading Terminal; and

(D) the Approved LNG Ship's requirements for utilities, to the extent available, at LNG Hub Facilities.

The Buyer shall cause the master of the relevant Approved LNG Ship to promptly notify the Seller Group and/or the LNG Hub Facilities Operator regarding any change in the relevant operational conditions of the Approved LNG Ship from those previously notified.

9.7.2 No later than ninety-six (96) hours prior to the anticipated ETA, the master of the Approved LNG Ship shall give notice by email confirming or amending the latest ETA notice. If this ETA subsequently changes by more than six (6) hours, the master shall promptly give notice of the corrected ETA to the Seller Group and/or the LNG Hub Facilities Operator

9.7.3 No later than seventy-two (72) hours prior to the anticipated ETA, the master of the Approved LNG Ship shall give notice by email confirming or amending the latest ETA notice. If this ETA subsequently changes by more than six (6) hours, the master shall promptly give notice of the corrected ETA to the Seller Group and/or the LNG Hub Facilities Operator.

9.7.4 No later than forty-eight (48) hours prior to the anticipated ETA, the master of the Approved LNG Ship shall give notice by email confirming or amending the latest ETA notice. If this ETA subsequently changes by more than six (6) hours, the master shall promptly give notice of the corrected ETA to the Seller Group and/or the LNG Hub Facilities Operator.

9.7.5 No later than twenty-four (24) hours prior to the anticipated ETA, the master of the Approved LNG Ship shall give notice by email confirming or amending the latest ETA notice. If this ETA subsequently changes by more than three (3) hours, the master shall promptly give notice of the corrected ETA to the Seller Group and/or the LNG Hub Facilities Operator.

9.7.6 No later than twelve (12) hours prior to the anticipated ETA, the master of the Approved LNG Ship shall give notice by email confirming or amending the latest ETA notice. If this ETA subsequently changes by more than one (1) hour, the master shall promptly give notice of the corrected ETA to the Seller Group and/or the LNG Hub Facilities Operator.

9.7.7 The master of the Approved LNG Ship shall send a final ETA notice by email five (5) hours prior to the Approved LNG Ship's arrival at the Pilot Boarding Station at the LNG Hub Facilities.

9.8 Notice of Readiness

9.8.1 The master of each Approved LNG Ship, or such master's agent, shall give notice of readiness to the Seller Group and/or the LNG Hub Facilities Operator (**"Notice of Readiness"** or **"NOR"**) upon such Approved LNG Ship's arrival at the Pilot Boarding Station specifying that the Approved LNG Ship is in all respects ready to proceed to berth and commence loading at the LNG Hub Facilities.

9.8.2 The NOR shall be effective:

(A) if tendered prior to the start of the Arrival Window, at the earlier of:

(1) [***]; and

(2) the time at which the Approved LNG Ship is berthed and is in all respects ready to commence loading, and

(B) if tendered at any time during the Arrival Window, at the earlier of:

(1)[***]; or

(2)the time at which the Approved LNG Ship is berthed and is in all respects ready to commence loading, and

(C) if tendered after the end of the Arrival Window, then the time at which the Approved LNG Ship is berthed and is in all respects ready to commence loading.

9.8.3 [***]

9.9 Berthing Assignments

9.9.1 The Seller Group shall procure that if an Approved LNG Ship tenders NOR before the end of the Arrival Window, it shall be permitted to berth and commence loading during the applicable Arrival Window in priority to all other vessels.

9.9.2 If the master of an Approved LNG Ship does not give a NOR by the end of the Arrival Window, but does give a NOR within [***] hours after the end of the Arrival Window, the Seller Group shall use reasonable endeavours to procure that the LNG Hub Facilities Operator shall berth the Approved LNG Ship as soon as reasonably practicable in order to load the Cargo in a non-discriminatory manner in accordance with normal shipping industry practise and priority arrangements as included in the Facilities Manuals; *provided,* however, that unless otherwise agreed by the Seller Group, the Seller Group shall have no obligation to use such efforts to berth an Approved LNG Ship that tenders NOR more than [***] hours after the end of its Arrival Window. The Arrival Window shall be deemed to have been amended accordingly and a NOR deemed to have been given effective at the time the Approved LNG Ship is berthed and is in all respects ready to load. If, as of the [***] hour after the end of the Arrival Window, the Approved LNG Ship has not tendered NOR, and the Seller Group is unable to reschedule loading of the relevant Cargo, the Scheduled Loading Quantity that the Buyer failed to take (for reasons other than those in Clauses 7.4.1 (A) to (F) (inclusive)) shall be deemed to be a Cargo Take or Pay Quantity in accordance with Clause 7.4.1.

9.10 Arrival Temperature and Cool Down Services

9.10.1 The Buyer shall ensure that each Approved LNG Ship retains, prior to arrival at the Pilot Boarding Station, sufficient heel quantity of LNG, based on normal operations of such Approved LNG Ship (including adequate provision for any mechanical problems of which the Buyer or the Transporter is aware), to maintain, for a period of not less than [***] hours after the end of the Arrival Window, a cargo tank temperature that (i) meets GTT guidelines in the case of membrane cargo containment systems, and (ii) is at least minus one hundred and ten (-110) degrees Celsius at the equatorial ring in the case of moss cargo containment systems, so as to be sufficiently cold to permit prompt and continuous loading of LNG at the rate required by the Facilities Manuals and up to the maximum loading rate allowed by such Approved LNG Ship (the "**Arrival Temperature**").

9.10.2 If a loading of a Cargo onto an Approved LNG Ship is delayed until after the end of the period that an Approved LNG Ship is required to maintain the Arrival Temperature and such delay is attributable to the Seller Group (which shall include, for the avoidance of doubt, any reasons attributable to the LNG Hub Facilities Operator, the FLNG Facility Operator, or Seller's Force Majeure) then, if requested by the Buyer and subject to the Buyer demonstrating that the Approved LNG Ship is no longer at the Arrival Temperature, the Seller Group may (at the Seller Groups' discretion) provide cool down services at the Loading Terminal. Any LNG supplied to the Buyer as part of such cool down services shall be for the Seller Group's account and supplied without cost to the Buyer. [***]

9.10.3 If, [***] Such costs shall be invoiced in accordance with Clause 12.1.1 at the Base Contract Price applicable to the Cargo in question, and be payable in accordance with Clause 12.3.2.

9.10.4 If as a result of events or circumstances occurring while the Approved LNG Ship is at the unloading terminal where it berthed immediately prior to arrival at the Loading Terminal the Buyer requires cool down services in respect of the Approved LNG Ship, the Buyer may request and the Seller Group may (at the Seller Group's sole discretion), provide such cool down services, [***]. Such costs shall be invoiced in accordance with Clause 12.1.1 at the Base Contract Price applicable to the Cargo in question, and be payable in accordance with Clause 12.3.2.

9.10.5 In no circumstances shall the Seller Group be obliged to provide cool down services with respect to any Approved LNG Ship where the relevant cool down services are required by reason of a gassing-up operation, which was not immediately followed by a cooling-down operation using Natural Gas.

9.10.6 Any LNG supplied by the Seller Group to the Buyer for purpose of cool down services shall not count towards delivery of the AACQ.

9.11 Cargo Loading

9.11.1 The Seller Group and Buyer shall commence loading or cause it to be commenced upon completion of berthing and shall co-operate with each other to complete loading, or cause it to be completed, safely, expeditiously and effectively. The Seller Group and Buyer shall procure that personnel fluent in the English language are available to enable all communications at the FLNG Facility and/or the LNG Hub Facilities to be conducted in English.

9.11.2 The procedure for the loading of Cargoes under this Agreement (including in relation to any Natural Gas displaced or boiled off) shall be consistent with the terms of this Agreement and shall be agreed between the Parties and set out in the Facilities Manuals.

9.11.3 Any Approved LNG Ship shall be permitted to burn Natural Gas as fuel during loading and the Quantity Delivered shall be adjusted to take account for the Natural Gas consumed as a result in accordance with the provisions Schedule 3.

9.12 Loading Time

9.12.1 If any action, event or circumstance occurs or is, in the reasonable opinion of the Seller Group or the Buyer, likely to occur and, in the reasonable opinion of the Seller Group or the Buyer, the occurrence of such action, event or circumstance would, or is reasonably likely to, cause a delay to the berthing, loading or departure of an Approved LNG Ship, the Seller Group and the Buyer shall, without prejudice to the provisions of this Clause 9.12, discuss in good faith and use their reasonable endeavours to minimise, or to avoid, any such delay, and at the same time shall cooperate with each other to mitigate against or to avoid the occurrence of any similar delay in the future.

9.12.2 Allowed laytime at the LNG Hub Facilities for completion of loading of a Cargo on an Approved LNG Ship (**"Allowed Laytime"**) shall be as follows, measured in each case from the time the NOR becomes effective in accordance with Clause 9.8.2:

(A) [***]

(B) Allowed Laytime shall be extended by any period of delay which is caused by one or more of the following (and accordingly, if the Approved LNG Ship is already on Demurrage, any period of delay which is caused by one or more of the following shall not be counted or included in calculating the time in respect of which Seller Group are liable for Demurrage):

(1) reasons attributable to the actions or omissions of the Buyer, the Transporter, the relevant Approved LNG Ship, or its master, crew, owner or operator;

(2) a Force Majeure Event;

(3) if applicable, night time berthing restrictions;

(4) Adverse Weather,

[***]

9.12.3 Used laytime in loading a Cargo on an Approved LNG Ship at the LNG Hub Facilities (**"Used Laytime"**) shall begin to count from the time the NOR becomes effective.

9.12.4 Used Laytime shall continue to run until:

(A) if the relevant Approved LNG Ship has berthed at the Loading Terminal with respect to such Cargo, Completion of Loading; or

(B) if the relevant Approved LNG Ship has not berthed at the Loading Terminal with respect to such Cargo, the earliest to occur of:

(1) the Buyer providing notice to the Seller Group that it will not take the relevant Cargo, in which case the provisions of Clause 7.4 will apply; and

(2) the Seller Group providing notice to the Buyer that the Seller Group will not make available or continue to make available the relevant Cargo, in which case the provisions of Clause 7.6 (or Clause 5.3.9 if applicable to a Commissioning Cargo) will apply.

For the avoidance of doubt, if a Cargo is scheduled to be delivered in multiple parcels, Completion of Loading shall occur when the final parcel of LNG has been loaded.

9.12.5 In the event Used Laytime exceeds Allowed Laytime (including any extension in accordance with Clause 9.12.2), the Seller Group shall:

(A) credit to the Buyer's account, Demurrage in respect of the number of days, or pro rata for fractions thereof, by which Used Laytime exceeds Allowed Laytime;

(B) if the Approved LNG Ship arrives at the Arrival Temperature and ready to load, pay an amount on account of excess boil-off, equal to the following:

(1) the Contract Price applicable to the relevant Cargo;

multiplied by:

(2) the Daily Boil-off Rate;

(3) the gross capacity of the Approved LNG Ship, converted to MMBtu using the heating value of LNG; and

(4) the number of days, or pro rata for fractions thereof, by which Used Laytime exceeds Allowed Laytime;

provided that, following Future Facilities COD, the product of Clause (2) through (4) shall not exceed the quantity of LNG on board the Approved LNG Ship at the time it tenders NOR.

The boil-off amount calculated and payable under this Clause 9.12.5 shall be adjusted to take account of boil-off incurred as a result of multiple berthings as accounted for in accordance with Clauses 12.2 and 12.5 of Schedule 3. For the avoidance of doubt boil-off incurred as a result of multiple berthings of an Approved LNG Ship shall be for the account of the Seller Group. Such payments shall be without prejudice to the provisions of Clause 10.1.15.

There shall be no double counting of boil-off under this Clause 9.12.5 and Schedule 3.

9.12.6 The Buyer shall issue to the Seller Group an invoice pursuant to Clause 12.1.3 for amounts due under Clause 9.12.5 within ninety (90) days.

9.13 **Departure of Approved LNG Ship**

9.13.1 The Buyer shall cause the Approved LNG Ship to depart safely (including taking into account safety parameters of the Approved LNG Ship, the FLNG Facility, the LNG Hub Facilities and the Future Facilities) and expeditiously from the berth after Completion of Loading. The Seller Group shall co-operate, or cause LNG Hub Facilities Operator to co-operate, in the safe and expeditious departure of the Approved LNG Ship from the berth.

9.13.2 Without prejudice to the provisions of Clause 9.13.1 if, as a result of any delay attributable to or period of time required as a result of the action or omission of the Buyer, the Approved LNG Ship or her master, or the Transporter, an Approved LNG Ship:

(A) is determined to be not ready to commence loading after being berthed, then the NOR shall be invalid and the Buyer and Seller Group shall discuss in good faith and use their reasonable endeavours to minimise the resulting delay, provided that the Seller Group shall be entitled, for safety and operational reasons (subject to the safety of the Approved LNG Ship), to require the Approved LNG Ship to leave the berth at utmost dispatch, whether or not other LNG ships are awaiting the berth; or

(B) occupies a berth at the LNG Hub Facilities after the end of earlier of Permitted Time or Used Laytime determined in accordance with Clause 9.12**,** and such delay in vacating the berth would disrupt the operations of the LNG Hub Facilities, the FLNG Facility or the Future Facilities, the Buyer and the Seller

Group shall discuss the matter in good faith and use their reasonable endeavours to minimise such delay, provided that the Seller Group shall be entitled (subject to the safety of the Approved LNG Ship) to require the Approved LNG Ship to leave the berth at utmost dispatch, whether or not other LNG ships are awaiting the berth. In the event the Seller Group incurs a liability to pay demurrage damages and/or excess boil-off to any Third Party with respect to the next scheduled vessel as a result of such delay, then the Buyer shall reimburse the Seller Group for all such amounts paid up to the amount as would have been payable by the Seller Group to the Buyer pursuant to this Agreement if the circumstances were reversed.

9.13.3 In the event an LNG ship fails to vacate the berth pursuant to this Clause 9.13 and the Buyer is not taking actions to cause it to vacate the berth, the Seller Group may affect such removal at the expense of the Buyer.

10. ANNUAL DELIVERY PROGRAMME

10.1 Annual Delivery Programme ("ADP")

10.1.1 The quantities of LNG to be made available for delivery by the Seller Group and taken by the Buyer in each Contract Year shall be scheduled in accordance with the following principles (the "**Scheduling Requirements**"):

(A) the AACQ shall be made available for delivery during each Contract Year in full cargo lots, with reference to the size of each ship to be specified by the Buyer for each Cargo;

(B) the Annual Delivery Programme for each Contract Year shall:

(1) incorporate the Seller Group's Annual LNG Production Forecast for such Contract Year;

(2) ensure that prior to the Future Facilities Commercial Operations Date there is no Inventory Conflict;

(3) ensure that the safety and operations of the FLNG Facility, the LNG Hub Facilities and Future Facilities are not adversely affected; and

(4) allow for the Seller Group to schedule any Scheduled Implementation Works Suspension and/or Scheduled Downtime permitted in accordance with Clauses 7.1.2 and 7.1.3 respectively.

10.1.2 In accordance with the provisions of this Clause 10, the Seller Group and the Buyer will work together in co-operation to develop the annual programme of LNG deliveries for each Contract Year (the **"Annual Delivery Programme"**). Subject to the Scheduling Requirements, all LNG deliveries shall be scheduled as far as reasonably practicable on a non-discriminatory basis between the Buyer and any other LNG buyers using the LNG Hub Facilities as a result of the development of a Future GTA Project.

10.1.3 On or before 1 August of each Contract Year, other than the first Contract Year, the Seller Group shall inform the Buyer in writing of the following information for the next Contract Year:

(A) the ACQ;

(B) [***]

(C) any Scheduled Downtime Quantity;

(D) [***]

(E) [***]

(F) [***]

(G) prior to the Future Facilities Commercial Operations Date, the Seller Group's good faith estimate of LNG to be produced from the FLNG Facility each day during such Contract Year (expressed in cubic metres and MMBtu) (**"Seller Group's Annual LNG Production Forecast"**);

(H) the expected periods of Scheduled Downtime and Scheduled Implementation Works Suspension; and

(I) prior to the Future Facilities Commercial Operations Date, the Seller Group's good faith estimate of LNG in the FLNG Facility storage tanks (in cubic metres) at the beginning of the Contract Year,

(the sum of (A) - [***] - (C) - (D) – (F) + (E) shall be the "**Provisional AACQ**" or "**PAACQ**").

10.1.4 On or before 1 September of each Contract Year, other than the first Contract Year, the Buyer shall notify the Seller Group in writing of the following information for the next Contract Year in each case based on the PAACQ notified by the Seller Group pursuant to Clause 10.1.3 above:

(A) the number of Cargoes the Buyer intends to take delivery of;

(B) the Buyer's proposed Cargo loading pattern for each month, in the form of proposed Arrival Windows (noting the requirements of Clause 10.1.6);

(C) any Make-Up Quantities that the Buyer desires to take in accordance with Clauses 7.5.2 and 7.5.3;

(D) the expected Approved LNG Ship nominated for each Cargo;

(E) the expected Scheduled Loading Quantity for each Cargo, which shall be based on full loads; and

(F) [***]

(the "**Proposed Annual Delivery Programme**").

10.1.5 The Buyer and the Seller Group shall, as soon as practicable after the exchange of information in accordance with Clauses 7.1.4, 10.1.3 and 10.1.4, consult and meet in good faith to agree on the Annual Delivery Programme.

10.1.6 The Parties acknowledge that the production profile of the FLNG Facility and (if applicable) Future Facilities through a Contract Year is dependent on weather conditions and this may result in higher quantities of LNG being produced pro rata in certain months compared to others. The Parties agree that such variations in the production profile of the FLNG Facility and (if applicable) Future Facilities through a Contract Year shall be reflected in the loading pattern of Cargoes in the Annual Delivery Programme and Specific Delivery Schedule. Subject to the foregoing, the Cargoes in the Annual Delivery Programme and Specific Delivery Schedule shall be otherwise allocated on a reasonably rateable and even basis throughout each Contract Year.

10.1.7 Each Annual Delivery Programme shall, for the next Contract Year, detail (without duplication):

(A) the AACQ, and each component thereof provided for in Clause 7.2.1;

(B) prior to the Future Facilities Commercial Operations Date, the Seller Group's Annual LNG Production Forecast;

(C) [***]

(D) any Scheduled Downtime Quantity;

(E) [***];

(F) in respect of each Cargo, details of:

(1) the Scheduled Loading Quantity;

(2) the quantity of LNG that represents Make-Up Quantity (if applicable);

(3) for information purposes only, the expected laytime (without amending the Allowed Laytime) (prior to the Future Facilities Commercial Operations Date);

(4) the Approved LNG Ship; and

(5) the Arrival Window, and

(G) such additional information as the Parties agree.

10.1.8 If the Buyer and the Seller Group cannot agree on the Annual Delivery Programme for any Contract Year by the date [***] days prior to the start of such Contract Year or in respect of the first Contract Year the date provided in Clause 10.2.3, then the Seller Group shall establish the Annual Delivery Programme taking into account:

(A) the Scheduling Requirements;

(B) any Cargo details agreed between the Buyer and Seller Group as agreed pursuant to discussions between the Parties under Clause 10.1.5;

(C) Buyer’s proposed Approved LNG Ship loading pattern as nominated in accordance with Clause 10.1.4 (with a corresponding Scheduled Loading Quantity to reflect a fully loaded Approved LNG Ship in accordance with the Approved LNG Ship gross capacity, taking account of heel requirements) provided that the Arrival Window for each Cargo will reflect the Scheduling Requirements and will be established on a non-discriminatory basis between the Buyer and any other LNG buyers using the LNG Hub Facilities; and

(D) the requirements of Clause 10.1.6.

10.1.9 [***]

(A) [***]

(B) [***]

(C) [***]

10.1.10 [***]

10.1.11 **End of Year Take or Pay**

(A) If, with respect to any Contract Year, the sum of (without double-counting any of the following items):

(1) the quantity of LNG taken by the Buyer in a Contract Year (which shall include any Seven Day Rule LNG taken in the following Contract Year but shall not include any Seven Day Rule LNG taken during such Contract Year) less Make-Up Quantities taken by the Buyer;

(2) any quantities of AACQ plus In Year Surplus Quantities not made available by the Seller Group due to the fault of the Persons in Clause 7.4.1(E) or Seller's Force Majeure;

(3) any quantities of AACQ plus In Year Surplus Quantities not taken for reasons of Buyer's Force Majeure;

(4) any quantities of AACQ plus In Year Surplus Quantities with respect to which a Cargo Take or Pay Obligation has arisen pursuant to Clause 7.4; and

(5) any quantities of AACQ plus In Year Surplus Quantities comprised in any Cargo that are deemed to have been taken by the Buyer following a suspension by the Buyer pursuant to Clause 22.5;

is less than the sum of:

(a) the AACQ (which shall, for the avoidance of doubt, exclude Make-Up Quantities [***]) plus In Year Surplus Quantities, with respect to such Contract Year [***],

(such shortfall being the "**Annual Take or Pay Quantity**"),

then the Seller Group shall invoice the Buyer in accordance with Clause 12.1.2 and the Buyer shall pay in accordance with Clause 12.3.2 for any amount equal to the product of:

(i) the Annual Take or Pay Quantity; and

(ii) the Annual Take or Pay Price as determined in accordance with Clause 10.1.12;

(the "**Annual Take or Pay Obligation**").

10.1.12 The "**Annual Take or Pay Price**" shall equal the arithmetic average Base Contract Price applicable for all months in the relevant Contract Year.

10.1.13 **End of Year Deliver or Pay**

(A) If, with respect to any Contract Year, the sum of (without double-counting any of the following items):

(1) the quantity of LNG made available by the Seller Group in a Contract Year (which shall include any Seven Day Rule LNG made available in the following Contract Year but shall not include any Seven Day Rule LNG made available during such Contract Year) less any Make-Up Quantities made available by the Seller Group in a Contract Year;

(2) any quantities of AACQ plus In Year Surplus Quantities not taken by the Buyer due to the fault of the Persons in Clause 7.6.1(D) or Buyer's Force Majeure;

(3) any quantities of AACQ plus In Year Surplus Quantities not made available for reasons of Seller Group's Force Majeure;

(4) any quantities of AACQ plus In Year Surplus Quantities with respect to which a Cargo Deliver or Pay Obligation has arisen pursuant to Clause 7.6, [***]; and

(5) any quantities of AACQ plus In Year Surplus comprised in any Cargo that is deemed to have been made available by the Seller Group following a suspension by the Seller Group pursuant to Clause 22.4

is less than the sum of:

(a) the AACQ (which shall, for the avoidance of doubt, exclude Make-Up Quantities [***]) plus In Year Surplus Quantities with respect to such Contract Year [***],

(such shortfall being the "**Annual Deliver or Pay Quantity**"),

then the Buyer shall invoice the Seller Group in accordance with Clause 12.1.3 and payment shall be made or credited [***] in accordance with Clause 12.3.2 for any amount equal to the product of:

(i) the Annual Deliver or Pay Quantity; and

(ii) the Annual Deliver or Pay Price as determined in accordance with Clause 10.1.14 multiplied [***];

(the "**Annual Deliver or Pay Obligation**").

10.1.14 The "**Annual Deliver or Pay Price**" shall equal the arithmetic average of the Base Contract Price applicable for all months of the relevant Contract Year.

10.1.15 [***]

10.2 **First Contract Year Annual Delivery Programme**

Development of the Annual Delivery Programme in respect of the first Contract Year shall be conducted pursuant to the provisions of Clause 10.1, provided that:

10.2.1 the notices required in Clause 10.1.3 shall be given on or before the date being forty-five (45) days following the Commissioning Start Date;

10.2.2 the notices required in Clause 10.1.4(A) shall be given on or before the date being sixty (60) days following the Commissioning Start Date; and

10.2.3 the Seller Group may determine the Annual Delivery Programme pursuant to Clause 10.1.8 if the Parties have not agreed the same on or before the date being ninety (90) days following the Commissioning Start Date.

In any event, the Annual Delivery Programme for the first Contract Year shall be finalised by no later than thirty (30) days prior to the start of the Arrival Window for the first Cargo to be delivered in such Contract Year, provided that the Buyer shall use reasonable endeavours to accept changes to any details already agreed between the Buyer and the Seller Group pursuant to Clauses 10.2.1 to 10.2.3 that fall within [***] days of such notice from the Seller Group. If the only change is the change in designation of a cargo, from a Commissioning Cargo to a Cargo, such change shall be deemed to be accepted.

10.3 **Extension Period Annual Delivery Programme**

There shall be an Annual Delivery Programme for each Contract Year in respect of any Extension Period pursuant to Clause 6.2 and the foregoing provisions of this Clause 10 shall apply to the necessary changes being made thereto on the basis that references to a Contract Year are to a Contract Year during the Extension Period.

10.4 **Specific Delivery Schedule**

10.4.1 No later than the fifteenth (15th) day of each month in each Contract Year, the Seller Group will issue to the Buyer a specific lifting programme (the **"Specific Delivery Schedule"** or **"SDS"**) showing the immediately following three (3) month plan of liftings which shall be identical to the Annual Delivery Programme (as such Annual Delivery Programme may have been adjusted or amended in accordance with Clause 10.5) for such period. Each Specific Delivery Schedule shall supersede the provisions of the applicable Annual Delivery Programme and any previous Specific Delivery Schedule for the months specified in such Specific Delivery Schedule. The Specific Delivery Schedule shall set out:

(A) for each Cargo to be delivered in the three (3) month period:

(1) the Arrival Window;

(2) the Scheduled Loading Quantity;

(3) the portion of LNG that represents Make-Up Quantity;

(4) the portion of LNG to which the [***] will apply, being LNG nominated as either [***] or (b) In Year Surplus Quantity or both;

(5) for information purposes only, the expected laytime (without prejudice to the Allowed Laytime) (prior to Future Facilities Commercial Operations Date);

(6) the name of the Approved LNG Ship to be utilised; and

(7) such additional information as the Parties agree, including details required for multiple berthings prior to the Future Facilities Commercial Operations Date.

10.4.2 If the Seller Group fails to issue a Specific Delivery Schedule as herein required, then the provisions of the previous Specific Delivery Schedule as applicable to such period shall apply, and to the extent that there is no Specific Delivery Schedule in respect of such period, the provisions of the Annual Delivery Programme as applicable to such period shall apply; provided always that: [***]

10.5 **Changes to Annual Delivery Programme or Specific Delivery Schedule**

10.5.1 If the Seller Group or the Buyer consider that it is necessary for an Annual Delivery Programme and/or Specific Delivery Schedule to be changed for any reasons affecting the Seller Group or the Buyer, including as a result of a Force Majeure Event, it shall give notice to the other Party of any proposed changes to such Annual Delivery Programme and/or Specific Delivery Schedule (such notice comprising an **"ADP/SDS Change Notice"**).

10.5.2 [***]

10.5.3 [***]

10.5.4 [***]

10.5.5 [***]

10.5.6 Approved LNG Ship substitution:

The Buyer shall be entitled to replace an Approved LNG Ship with a substitute Approved LNG Ship in any Annual Delivery Programme and/or Specific Delivery Schedule. The Buyer shall promptly notify the Seller Group of such change and the Seller Group shall update the ADP and/or the Specific Delivery Schedule accordingly if (i) the Buyer's ability to take delivery of the Scheduled Loading Quantity for the applicable Cargo is not affected by the change and (ii) the only change is the Approved LNG Ship and there is no other change to the ADP and/or SDS.

10.5.7 [***]

10.5.8 Upon:

(A) agreement of the Parties on a change to the Annual Delivery Programme and/or Specific Delivery Schedule;

(B) Buyer's nomination of any Approved LNG Ship change pursuant to Clause 10.5.6;

(C) Seller Group's nomination of any In Year Surplus Quantities pursuant to Clause 10.4.2; or

(D) any rescheduling of a Cargo agreed to by the Buyer and the Seller Group pursuant to Clause 7.4.1 or Clause 7.6.1,

the Annual Delivery Programme and/or Specific Delivery Schedule, as applicable, shall be amended accordingly and promptly provided by the Seller Group to the Buyer.

10.6 Information Sharing

Without prejudice to the other provisions of this Clause 10 or the generality of Clause 19.2, during the Contract Term prior to the Future Facilities Commercial Operations Date, the Seller Group's Representative shall provide the Buyer with daily, non-binding LNG production and inventory reports (and forecasts, if made) from the FLNG Facility, for the purposes of planning and scheduling by the Parties.

If so requested by either the Buyer or the Seller Group from time to time, the Parties shall promptly convene a meeting of the Marine Working Group to discuss any operational and safety issues with respect to any Approved LNG Ship that is scheduled in the current ADP or SDS, the FLNG Facility, the LNG Hub Facilities, the Future Facilities and/or the Marine Services, that relate to material non-compliance of such vessel, facilities or services with the requirements of this Agreement. The sharing of information under this Clause 10.6 shall be subject to any contractual obligations of confidentiality owed by the Buyer or the Seller Group (as applicable) in relation to such information.

11. CONTRACT PRICE

11.1 Base Contract Price

The price (in Dollars per MMBtu) payable by the Buyer for the LNG in respect of each Cargo (other than Commissioning Cargoes, In Year Surplus Quantities, and [***] amount pursuant to Clause 7.1.2) sold and made available under this Agreement shall, subject to Clause 11.4, be the following (the **"Base Contract Price"**):

[***]

11.2 **Commissioning Period Price**

The price (in Dollars per MMBtu) for the LNG in respect of each Commissioning Cargo sold and made available under this Agreement shall, subject to Clause 11.4, be the following (the **"Commissioning Period Price"**):

11.3 [***]

The price (in Dollars per MMBtu) for all In Year Surplus Quantities [***] shall, subject to Clause 11.4, be the following [***]:

[***]

11.4 **Replacement Index**

11.4.1 If any of the rates or indices used in this Agreement ceases to be published for any reason (other than temporarily) or ceases to exist or there is a fundamental change in the manner in which any such rate or index is calculated, the Parties will meet and discuss with the aim of jointly selecting a replacement rate or index, or replacement rates or indices, to be used in place of such rate or index (with adjustments as necessary or appropriate), the effects of which (so far as can be assessed at the time at which such replacement rate or index is selected) are as close as practicable (taking into account, among others, considerations of the relevant market coverage, depth, liquidity and volatility) to those that would have been expected of the original rate or index had the original rate or index continued to be published and used and had there been no fundamental change in the manner in which the original rate or index was calculated.

11.4.2 If the Parties do not reach agreement on a replacement rate or index within a period of sixty (60) days after the date of the occurrence of the circumstances referred to in Clause 11.4.1, then either Party may request that the matter be referred for determination by an Expert in accordance with Clause 23.3. The Expert is instructed to select the published rate or index or a combination of published rates or indices (in each case with adjustments as necessary or appropriate), the effects of which (so far as can be assessed at the time at which such replacement rate or index is selected) are as close as practicable (taking into account, among others, considerations of the relevant market coverage, depth, liquidity and volatility) to those that would have been expected of the original rate or index had the original rate or index continued to be published and used and had there been no fundamental change in the manner in which the original rate or index was calculated.

11.4.3 Subject to the adjustment under Clause 11.4.2, before all matters of dispute or difference arising under this Clause 11.4 have been finally agreed or decided, the relevant Contract Price will continue to apply. In circumstances where the cessation or (as the case may be) the cessation of publication referred to in Clause 11.4.1 has the effect that the relevant Contract Price is no longer capable of calculation, the Parties will provisionally calculate the relevant Contract Price using the published rate or index in effect for the date such rate or index was most recently published prior to the date of such cessation, subject to retrospective adjustment pursuant to the provisions of Clause 11.4.2.

11.4.4 If any rate or index used in this Agreement is not published for a particular date, but the publication containing such rate or index continues to be published and the rate or index itself continues to exist, the Parties will use the published rate or index in effect for the date such rate or index was most recently published prior to such particular date unless otherwise provided in this Agreement or agreed between the Parties.

11.5 [***]

11.5.1 [***]

11.5.2 [***]

11.5.3 [***]

11.5.4 [***]

11.5.5 [***]

11.5.6 [***]

11.5.7 [***]

11.6 **Price Review for Extension Term**

11.6.1 Not less than [***] before the expiry of the Initial Term and the First Extension Term if applicable, the Buyer shall submit to the Seller Group a price adjustment proposal that shall be determined by the Buyer taking account of the Price Adjustment Objectives ("**Price Adjustment Proposal**").

11.6.2 The Price Adjustment Proposal:

(A) may amend the Base Contract Price;

(B) [***]

(C) [***]

(D) shall apply for the First Extension Term (in the case of the first Price Adjustment Proposal) or the Second Extension Term (in the case of the second Price Adjustment Proposal);

(E) shall not change any other terms and conditions of this Agreement.

11.6.3 The objective of the price adjustment is to determine an LNG price for the First Extension Term and, if applicable, the Second Extension Term, that:

(A) [***]

(B) [***]

(C) [***]

(D) [***]

("**Price Adjustment Objectives**").

11.6.4 The Price Adjustment Proposal shall be valid and capable of acceptance or rejection or the submission of a counter-proposal for further non-binding negotiations between the Parties by the Seller Group until the date that is [***] prior to (i) the expiry of the Initial Term in respect of the First Extension Period, and (ii) the expiry of the First Extension Period in respect of the Second Extension Period, if applicable.

11.6.5 The Seller Group may accept or reject or make a counter-proposal in respect of the Price Adjustment Proposal in its sole discretion. If the Seller Group does not accept the Price Adjustment Proposal in writing by the date specified in Clause 11.6.4, the Seller Group shall be deemed to have rejected the Price Adjustment Proposal and the Contract Term shall not be extended.

12. **INVOICING AND PAYMENT**

12.1 **Invoices**

12.1.1 As soon as reasonably practicable after Completion of Loading of each Cargo of LNG made available hereunder, the Seller Group's Representative shall send to the Buyer an invoice showing:

(A) the Quantity Delivered together with the relevant documents showing the basis for such calculation

(B) that part of the Quantity Delivered to which [***] shall apply;

(C) the applicable Contract Price for the Cargo, determined in accordance with Clause 11;

(D) any applicable credit due from the Seller Group (which shall be broken down for each individual Seller) to the Buyer under this Agreement;

(E) the payment due from the Buyer to the Seller Group (which shall be broken down for each individual Seller) in respect of such Cargo, (which total amount will be calculated by multiplying the Quantity Delivered specified in Clause 12.1.1(A) by the relevant Contract Price) less any deduction in accordance with Clause 12.1.1(D);

(F) the designated bank accounts for each Seller in accordance with Clause 12.3.5, and the amount payable into each account.

12.1.2 If any other sums are due from the Buyer to the Seller Group or individual Sellers under this Agreement, including pursuant to Clause 11.5, then the Seller Group shall furnish an invoice to the Buyer specifying the applicable Clauses under this Agreement together with relevant supporting documents showing the basis for the calculation.

12.1.3 If any sums are due from the Seller Group to the Buyer under this Agreement, then the Buyer shall furnish to the Seller Group's Representative, with a copy to each Seller, an invoice showing the total owing by the Seller Group and each Seller's proportion of the sum due and specifying the applicable Clauses under this Agreement together with relevant supporting documents showing the basis for the calculation.

12.2 **Statements and Invoices for LNG Not Taken or Delivered**

12.2.1 With respect to any Cargo Take or Pay Quantity, as soon as reasonably practicable, the Seller Group's Representative's shall send to the Buyer an invoice showing the amount of the Cargo Take or Pay Quantity, the Cargo Take or Pay Price and the Cargo Take or Pay Obligation.

12.2.2 With respect to any Cargo Deliver or Pay Quantity, as soon as reasonably practicable, the Buyer shall send an invoice, which shall be issued in accordance with Clause 12.1.3 to the Seller Group's Representative, with a copy to each Seller, that shows the total owing by the Seller Group and each Seller's proportion of the Cargo Deliver or Pay Quantity, the Cargo Deliver or Pay Price, the Cargo Deliver or Pay Obligation and any Cargo Deliver or Pay Credit due.

12.3 **Payment**

12.3.1 Invoices shall be sent in accordance with Clause 26.

12.3.2 The Seller Group's payment of any invoice from the Buyer shall be satisfied by the application by each Seller of a credit to the Buyer for its proportion of the amount due on the first invoice issued by the Seller Group to the Buyer in accordance with Clause 12.1.1 after the expiration of [***] from the date of receipt of the Buyer's invoice. If the Seller Group does not make a Cargo available within [***] after the date of the Buyer's invoice (therefore being unable to fulfil the Seller Group's obligation to apply a credit), each Seller shall settle its proportion of such Buyer's invoice on or before the [***]after the expiration of such [***] by payment of the relevant sum due in Dollars in immediately available funds to an account or accounts with such bank and in such location as shall be designated by the Buyer in accordance with Clause 12.3.5. Subject to Clause 12.5, the Buyer shall settle any Seller Group's invoice on or before the [***] after the day on which such invoice together with customary supporting documents are received, by payment of the sum due in Dollars in immediately available funds to an account or accounts with such bank or banks and in such location or locations as shall be designated by the Seller Group in accordance with Clause 12.3.4. [***] each credit or payment by a Party of any amount owing hereunder shall be in the full amount due as set out in the other Party's invoice, without reduction or offset for any reason including Taxes, exchange charges or bank transfer charges. Any amounts due from Seller Group to the Buyer at the end of the contract term shall be payable within [***]of the date of receipt of the Buyer's invoice.

12.3.3 Each Seller's proportion of any credit [***] applied in accordance with Clause 12.3.2 shall be applied against the aggregate sum owing to such Seller as stated in the relevant invoice, and any remaining balance payable to the relevant Seller shall be payable by the Buyer to such Seller according to the payment instructions provided by such Seller pursuant to Clause 12.3.4 with respect to credits [***].

12.3.4 Subject to the following provisions in this Clause 12.3.4, each Seller shall designate one (1) bank account for receipt of payments from the Buyer (each such account a "**Seller's Account**"). If a Seller is requested to direct a portion of its proceeds directly to a State, it may designate one (1) further account for such payments (each a "**State Account**"). Such account(s) shall be initially designated not later than [***] after the Effective Date and thereafter with not less than [***] notice before any re-designation is to be effective. Such accounts and any re-designation by a Seller shall be subject to satisfaction of the Buyer's compliance processes. A Seller may not designate an account that is affected by Trade Sanctions.

12.3.5 The Buyer shall designate a bank account as the Buyer's Account for receipt of payments from the Seller Group, initially not later than the date that is [***] days after the Effective Date and thereafter with not less than [***] notice before any re-designation is to be effective. Such bank account and any re-designation by the Buyer shall be subject to satisfaction of the Seller Group's compliance processes. The Buyer may not designate an account that is affected by Trade Sanctions.

12.3.6 If a Seller directs the Buyer to pay monies into a State Account as per Clause 12.3.4 in accordance with Clause 12.1.1, the payment of such monies shall discharge that part of the Buyer's payment obligations to the Seller.

12.3.7 If the due date of any invoice does not fall on a Business Day, such invoice shall become due and payable on the next Business Day following such due date.

12.4 Delay in Payment

If any Seller or the Buyer fails to apply a credit or make payment of any sum as and when due under this Agreement, any uncredited or unpaid amount thereof shall bear interest from (but excluding) the due date until (and including) the day it was credited or paid [***]

in full including interest, at the Interest Rate [***] per annum. Interest shall be paid on the date when payment of the amount credited or due is made. Any interest payable under this Clause 12.4 shall: (i) accrue daily; (ii) be calculated as simple interest, without any compounding of interest (iii) be calculated on the basis of a three hundred sixty (360) Day year. If the Buyer fails to make payment of any sum as and when due under this Agreement, the Seller Group or any Seller may draw on the

Acceptable Credit Support in accordance with Clause 12.7 in addition to any other remedies the Seller Group or Seller may have.

12.5 **Disputed Invoice**

12.5.1

(A) If the Seller Group, or an individual Seller and the Buyer disagree on the correct amount owing under an invoice, each Seller or the Buyer, as the case may be, shall make payment (including by way of applying credit under Clause 12.3.2) of the full amount of such invoice (other than in the case of manifest error (namely an obvious indisputable error)) and shall promptly notify the other Party of disputed amount and the reasons for such disagreement. Any necessary correction and consequent adjustment shall be made within fourteen (14) days after agreement or determination of the correct amount, together with interest on any amount remaining payable pursuant to this Clause 12.5.

(B) If the Buyer or the Seller Group or an individual Seller disagrees due to reasons of manifest error (namely an obvious indisputable error) as to the correct amount owing under an invoice, the Buyer or the Seller Group or each Seller shall make payment (including by way of applying credit under Clause 12.3.2) of the undisputed invoiced amount only and shall, promptly notify the other Party of the reasons for withholding the disputed amount. Any necessary correction and consequent adjustment shall be made within fourteen (14) days of agreement or determination of the correct amount.

(C) An invoice may be disputed by the paying party, or modified by the invoicing party, by written notice delivered to the other Party before the end of [***] of such receipt or sending of the invoice, as the case may be. If no such notice is served within this period, such invoice shall be deemed correct and accepted by both Parties.

12.5.2 Except for any payments following the identification of an error in the invoice issued pursuant to Clause 12.5.3, the Party paying the amount of any adjustment referred to in Clause 12.5.1(A) shall pay interest to the other Party on the amount of such adjustment at the Interest Rate [***] for the period from the date following the due date up to and including the date of payment of the adjustment in full including interest, or in circumstances contemplated by Clause 12.5.3, on and from the date on which the suspected inaccuracy is first notified up to and including the date when the retroactive adjustment is made. Any interest payable under this Clause 12.5.2 shall: (i) accrue daily; (ii) be calculated as simple interest, without any compounding of interest; (iii) be calculated on the basis of a three hundred sixty (360) Day year.

12.5.3 Any errors found in an invoice or credit note which are caused by the inaccuracy of any measuring or analysing equipment or device shall be corrected or referred to an Expert in accordance with Clause 23.3 and shall be settled in the same manner as is set out above in this Clause 12.5.

12.6 **Continuation in Effect of Clause 12**

The provisions of this Clause 12 shall remain in effect notwithstanding the expiration or termination of this Agreement until payment has been made for all amounts that have accrued as of the expiration or termination of this Agreement.

12.7 **Payment Security**

12.7.1 The Buyer shall procure the issuance and delivery to the Seller Group, no later than [***], a Deed of Guarantee from [***] for the Buyer Credit Support Amount.

12.7.2 The Buyer shall maintain Acceptable Credit Support in full force and effect until the expiry of [***], and:

(A) each Deed of Guarantee delivered to the Seller Group under this Clause 12.7 shall have a scheduled expiry date falling not earlier than [***]; and

(B) each Letter of Credit and each Bank Guarantee delivered to the Seller Group under this Clause 12.7 shall have a scheduled expiry date falling not less [***] after the effective date of such Letter of Credit or Bank Guarantee (as applicable).

12.7.3 The Buyer may only replace the Acceptable Credit Support:

(A) with respect to a Deed of Guarantee when required pursuant to Clause 12.7.5;

(B) with respect to any Bank Guarantee or Letter of Credit when required pursuant to Clauses 12.7.6 and 12.7.8; or

(C) with the consent of the Seller Group.

12.7.4 The Buyer shall deliver the latest audited annual financial statements for the Acceptable Affiliate providing a Deed of Guarantee within [***] days following a request by any member of the Seller Group during the Contract Term.

12.7.5 With respect to each Deed of Guarantee delivered to the Seller Group as Acceptable Credit Support, in the event that:

(A) such Deed of Guarantee is not in full force and effect for any reason; or

(B) the Credit Support Provider is no longer an Acceptable Affiliate,

the Buyer shall procure the issuance and delivery to the Seller Group of a replacement Acceptable Credit Support within [***] after the occurrence of such event.

12.7.6 With respect to each Letter of Credit and each Bank Guarantee that is delivered to the Seller Group as Acceptable Credit Support, the Buyer shall procure the issue and delivery to the Seller Group of replacement Acceptable Credit Support by the date that is [***] prior to the scheduled expiry date of such Letter of Credit or Bank Guarantee (as applicable).

12.7.7 If the Buyer fails to replace any Bank Guarantee or Letter of Credit when required by the time specified in Clause 12.7.6, immediate demand for payment of all undrawn amounts under such Letter of Credit or Bank Guarantee may be made by the named beneficiary in accordance with its terms (and each Letter of Credit or Bank Guarantee shall acknowledge and confirm such right to do so). Any payment by the Buyer's Credit Support Provider following such demand shall be made to the Escrow Account and shall be held, applied and reimbursed (as applicable) on the terms and subject to the conditions of the Escrow Arrangements. In the event that such Escrow Arrangements have not been agreed and implemented by the date that is ninety (90) days after the date of issuance of any Bank Guarantee or Letter of Credit, the relevant named beneficiary of such Acceptable Credit Support shall be entitled (acting reasonably) to establish and implement the escrow arrangements with the relevant Acceptable Financial Institution when needed.

12.7.8 Without prejudice to Clause 12.7.6, with respect to each Letter of Credit and each Bank Guarantee delivered to the Seller Group as Acceptable Credit Support, if the Buyer becomes aware that:

(A) such Letter of Credit or Bank Guarantee (as applicable) is not in full force and effect for any reason; or

(B) the relevant Credit Support Provider is no longer an Acceptable Credit Support Provider,

the Buyer shall procure the issuance and delivery to the Seller Group of replacement Acceptable Credit Support within [***] after the occurrence of the event.

12.7.9 Any replacement Acceptable Credit Support shall be in full force and effect when delivered to the Seller Group.

12.7.10 Once replacement Acceptable Credit Support is delivered to the Seller Group in full force and effect in accordance with Clauses 12.7.5, 12.7.8 and 12.7.9:

(A) the Seller Group shall return the original Deed of Guarantee, Letter of Credit or Bank Guarantee that has been replaced to the Buyer promptly upon the Seller Group receiving the replacement Acceptable Credit Support; and

(B) the Seller Group shall no longer be entitled to, and shall not, make demand for payment under the Deed of Guarantee, Letter of Credit or Bank Guarantee that has been replaced.

12.7.11 A Seller, or the Seller Group's Representative on behalf of a Seller, may make demands for payment under the Deed of Guarantee, Letter of Credit or Bank Guarantee if the Buyer fails to make a payment due by it in accordance with the provisions of this Agreement. Any payment by the Acceptable Credit Support Provider following such demand shall be made to the respective Seller's Accounts with respect to the amounts secured by the Acceptable Credit Support, and such payment shall be deemed to have been made as a payment to each of the claiming Sellers in the amount paid to each claiming Seller.

13. TAXES AND CHARGES

13.1 Seller Group's Responsibility

13.1.1 The Seller Group shall be liable for, and shall indemnify and hold harmless the Buyer from and against [***].

13.1.2 The foregoing indemnity under this Clause 13.1, shall not apply to Taxes that

(A) are incurred and resulting from any activities of the Buyer not directly related to this Agreement or to the LNG to be sold under this Agreement. Such activities not directly related to this Agreement or to the LNG to be sold under this Agreement shall include but not be limited to :

(1) (i) the sale, purchase, transportation and/or other utilization by the Buyer of LNG acquired outside of this Agreement and/or (ii) any sale, encumbrance (including but not limited to establishing a security right over LNG), transfer, granting of options, rights of first refusal or of any other rights whatsoever on LNG by the Buyer in either State to any party other than a Seller;

(2) any storage of LNG by the Buyer in either State, provided always that all activities related to any Approved LNG Ship waiting for the FLNG Facility to produce sufficient LNG to deliver a Cargo shall not constitute storage and shall fall within the activities referred to in Clause 13.1.1;

(3) any transportation or transportation related activities of LNG by the Buyer in either State (other than the transportation in the nature of Export of LNG under this Agreement as provided for in Clause 13.1.1 above).

(B) result from any permanent establishment of the Buyer in either the Islamic Republic of Mauritania or the Republic of Senegal **[***]**.

13.1.1 For the avoidance of doubt, each Seller for its respective LNG SPA Participation shall be the Exporter of Record of LNG sold and delivered under the Agreement.

13.2 Buyer's Responsibility

13.2.1 The Buyer shall be liable for, and shall indemnify and hold harmless each Seller from and against, [***]

(A) [***]

(B) [***]

13.2.2 The foregoing indemnity under this Clause 13.2, shall not apply to Taxes that:

(A) are incurred and resulting from any activities of a Seller or an Affiliate thereof not directly related to this Agreement;

(B) result from any permanent establishment of the Seller in the jurisdiction imposing the Tax.

13.3 Tax Refunds

Where a payment has been made under this Clause 13 and the recipient of such payment receives or is entitled to receive a refund in respect of Taxes which gave rise to the right to that payment (whether by way of actual receipt, credit, set-off or otherwise), the recipient ("**Payer**") shall repay, or cause to be repaid, to the other Party ("**Payee**") a part of that payment equal to the amount of the refund effectively received or enjoyed, less any reasonable costs incurred in obtaining the refund, and less any Taxes levied or leviable in respect of that refund. The Payer shall notify the Payee promptly following the receipt of any such refund. The Payee shall thereafter furnish the Payer an invoice in accordance with Clause 12.1 and the payment of such invoice shall be made in accordance with Clause 12.3.

13.4 Procedure for Payment of Taxes

Whenever either Buyer or Seller Group become aware of a potential or actual liability to make any payment of Taxes which might give rise to a claim under this Clause 13, they shall give notice of the circumstances to the other Party as soon as reasonably practicable, in order to allow both Parties reasonable opportunity to seek to minimise their liability for such Taxes, acting always in compliance with applicable Laws. Each Party shall give the other Party such assistance as is reasonable in the circumstances in this regard, and Buyer or Seller Group (as appropriate) shall not make any payment of such Taxes until the due date on which such Taxes are due and payable in accordance with the relevant tax regulations unless an early payment could result in a reduction of the liability to such Taxes. In order to allow the Parties to make payments of Taxes in full and without neglecting compliance with any tax, royalty, duty or other impost levied, each Party agrees that if requested by the other Party, it will diligently complete, execute and arrange for any required certification and/or document in a manner reasonably satisfactory to the other Party, and will deliver to the other Party and/or to any Competent Authority as the other Party reasonably directs, copies of any such document.

14. **QUALITY**

14.1 **LNG Specifications**

The LNG to be delivered by the Seller Group to the Buyer under this Agreement shall at the time of delivery at the Delivery Point, in the gaseous state, comply with the quality specifications set out in Schedule 4 (the **"Specifications"**).

14.2 **Off-Specification LNG Before Delivery**

14.2.1 If the Seller Group, acting as Reasonable and Prudent Operator, becomes aware prior to loading a Cargo that the LNG will not comply with the Specifications (**"Off-Specification LNG"**), the Seller Group's Representative shall promptly (but in any case prior to the commencement of loading) send a notice to the Buyer indicating in as much detail as possible the nature and extent to which such LNG is likely to be Off-Specification LNG.

14.2.2 Following receipt of Seller Group's notice pursuant to Clause 14.2.1, the Buyer shall use reasonable endeavours to accept such Off-Specification LNG. In no circumstances shall the Buyer be obliged to accept such LNG where the Buyer's estimate of the costs referred to in Clause 14.2.3 (A) will exceed the amount which the Buyer is able to claim pursuant to Clause 14.2.5.

14.2.3 Within forty-eight (48) hours of receipt of the Seller Group's notice pursuant to Clause 14.2.1:

(A) the Buyer shall notify the Seller Group of the Buyer's reasonable estimate of all reasonable documented direct losses, costs and expenses that may be incurred by the Buyer [***] (i) in accepting, treating or disposing of such Off-Specification LNG on the Approved LNG Ship or in the unloading terminal and (ii) in remedying any direct damage to the Approved LNG Ship and unloading terminal arising from accepting, treating or disposing of such Off-Specification LNG; or

(B) if the Buyer determines, in good faith and in the Buyer's reasonable opinion, the Off-Specification LNG would prejudice the safe and reliable operation of the Approved LNG Ship or any LNG unloading terminal, or would not be acceptable to the Transporter and/or the operator of any unloading terminal, then the Buyer shall be entitled to reject delivery of such Off-Specification LNG by giving notice to the Seller Group.

14.2.4 If the Buyer has provided its estimate pursuant to Clause 14.2.3(A), then the Seller Group shall promptly determine, in its sole discretion, and notify the Buyer whether:

(A) the Seller Group shall make such LNG available for delivery to the Buyer at the Delivery Point in accordance with this Agreement; or

(B) the Seller Group shall not make such LNG available for delivery to Buyer and the provisions of Clause 7.6 shall apply.

14.2.5 Where the Seller Group determines pursuant to Clause 14.2.4(A) that it shall make Off-Specification LNG available for delivery to the Buyer, then the Seller Group shall be liable to reimburse the Buyer for all reasonable documented direct losses, costs and expenses [***] incurred by Buyer [***] (i) in accepting, treating or disposing of such Off-Specification LNG on the Approved LNG Ship or in the receiving facilities and (ii) in remedying any direct damage to the Approved LNG Ship and receiving facilities arising from accepting, treating or disposing of such Off-Specification LNG; provided that the Seller Group's liability under this Clause 14.2.5 shall not exceed an amount equal to the estimated cost notified by Buyer pursuant to Clause 14.2.3 [***]. The Buyer shall use reasonable endeavors to mitigate such costs.

14.2.6 If the Buyer notifies the Seller Group that it rejects the Off-Specification LNG pursuant to Clause 14.2.3(B), then the Seller Group shall be deemed to have failed to make available such Cargo and the provisions of Clause 7.6 (or Clause 5.3.9 if applicable to a Commissioning Cargo) shall apply to such quantities of Off-Specification LNG.

14.2.7 The Buyer shall promptly invoice the Seller Group for amounts due under this Clause 14.2 in accordance with Clause 12.1.3.

14.2.8 The Seller Group may sell or otherwise dispose of any Off-Specification LNG rejected or otherwise not taken by the Buyer in accordance with Clause 14.2.3(B) or 14.2.4(B) for the Seller Group's own account, without restriction.

14.3 **Off-Specification LNG After Delivery**

14.3.1 Following the commencement of loading a Cargo, including after Completion of Loading, if either Party becomes aware that the LNG is Off-Specification LNG and/or does not meet the expected specification notified to Buyer pursuant to Clause 14.2.1 (if applicable), then upon becoming aware thereof such Party shall promptly notify the other Party of such Off-Specification LNG and either Party may by notice suspend delivery of such LNG. In no circumstances shall the Buyer be obliged to accept such LNG where the Buyer's estimate of the costs referred to in Clause 14.3.2(A) will exceed the amount which the Buyer is able to claim pursuant to Clause 14.3.4.

14.3.2 Within forty-eight (48) hours of a Party giving notice pursuant to Clause 14.3.1:

(A) if the Buyer is able, using reasonable endeavours, to transport and treat the Off-Specification LNG to meet the Specifications (or to otherwise make such LNG marketable), then the Buyer shall accept delivery of such Off-Specification LNG and the Seller Group shall be liable to reimburse the Buyer for all reasonable documented direct losses, costs and expenses [***] incurred by Buyer [***] (i) in accepting, treating or disposing of such Off-Specification LNG at the Approved LNG Ship or in the receiving facilities and (ii) in remedying any direct damage to the Approved LNG Ship and receiving facilities arising from accepting, treating or disposing of such Off-Specification LNG; or

(B) if the Buyer determines in good faith that it cannot, despite using reasonable endeavours, transport and treat the Off-Specification LNG to meet the Specifications (or to otherwise make such LNG marketable), then the Buyer shall be entitled to reject delivery of such Off-Specification LNG by giving notice to the Seller Group.

14.3.3 Following the exercise by the Buyer of its rejection right pursuant to Clause 14.3.2(B):

(A) the Seller Group shall be deemed to have failed to make available the entirety of such Cargo (including any loaded portion) and the provisions of Clause 7.6 (or Clause 5.3.9 if applicable to a Commissioning Cargo) shall apply to such quantities of Off-Specification LNG;

(B) title to and all risks (including risk of loss) in respect of such quantities of Off-Specification LNG shall nevertheless have passed from the Seller Group to the Buyer at the Delivery Point in accordance with Clause 8;

(C) the Buyer shall be entitled to dispose of the loaded portion of such Off-Specification LNG Cargo in any manner that the Buyer, acting in accordance with the standards of a Reasonable and Prudent Operator, deems appropriate; and

(D) the Seller Group shall indemnify Buyer for all reasonable documented direct losses, costs and expenses [***] incurred by Buyer [***] (i) in accepting, treating or disposing of such Off-Specification LNG at the Approved LNG Ship or in the receiving facilities and (ii) in remedying any direct damage to the Approved LNG Ship and receiving facilities arising from accepting, treating or disposing of such Off-Specification LNG, including any costs incurred in respect of services provided by Third Parties to dispose of such Off-Specification LNG, less any proceeds received by the Buyer in relation to the disposal of such Off-Specification LNG, provided that following consideration of any such proceeds received by the Buyer, in no event shall the Seller Group be entitled to receive an amount greater than the quantity of Off-Specification LNG delivered multiplied by the Contract Price applicable to the Cargo.

14.3.4 The Seller Group's liability to the Buyer under Clause 14.3.2(A) shall not exceed an amount equal to [***] of the Scheduled Loading Quantity multiplied by the Contract Price for the Cargo. The Seller Group's liability to the Buyer under Clause 14.3.3(D) shall not exceed an amount equal to [***] of the Scheduled Loading Quantity multiplied by the Contract Price for the Cargo.

14.3.5 The Buyer shall promptly invoice the Seller Group for amounts due under this Clause 14.3 in accordance with Clause 12.1.3.

14.3.6 The Seller Group may sell or otherwise dispose of any Off-Specification LNG rejected or otherwise not taken by the Buyer in accordance with Clause 14.3.2(B) for the Seller Group’s own account, without restriction.

14.3.7 For the avoidance of doubt, this Clause 14.3 shall apply if, after the Completion of Loading, the Buyer becomes aware that the LNG delivered was, at the time of delivery, Off-Specification LNG and does not meet the expected specification notified pursuant to Clause 14.2.1.

14.4 Sole Remedies

14.4.1 The Parties hereby acknowledge and agree that the remedies expressly stated in this Clause 14 shall be in the nature of damages and shall be the Buyer's sole and exclusive remedies in damages or otherwise for liabilities arising out of or in connection with the Seller Group's delivery of Off-Specification LNG, and represents a proportionate protection of the legitimate interests of the Buyer in connection with the applicable delivery of Off-Specification LNG.

14.4.2 The Seller Group shall have the right to cause a Third Party auditor to verify any invoices issued in relation to or any amounts described in this Clause 14 in accordance with Clause 19.3.

15. MEASUREMENTS AND TESTING

The procedures in relation to measurements and tests carried out under or pursuant to this Agreement shall be those set out in Schedule 3.

16. FORCE MAJEURE

16.1 Seller's Force Majeure

No Seller shall be in breach of any of its obligations, or be liable for any delay or failure in performance, under this Agreement to the extent that its performance is prevented, impeded or delayed by an act, event or circumstance or combination of such acts, events or circumstances which are beyond the reasonable control of that Seller acting as a Reasonable and Prudent Operator (**"Seller's Force Majeure"**). Subject to the foregoing principles, Seller's Force Majeure shall include, but not be limited to, the following acts, events and circumstances:

16.1.1 fire, explosion, flood, earthquake, lightning, storms, hurricanes, or other act of God or natural physical disaster or navigational or maritime peril;

16.1.2 acts of war (declared or undeclared), invasion, act of foreign enemies, hostilities, civil war, insurrection of military or usurped power;

16.1.3 terrorism, riot, rebellion, revolution, sabotage or civil unrest;

16.1.4 ionising radiations or contamination by radioactivity from any nuclear fuel or from any nuclear waste from the combustion of nuclear fuel, radioactive toxic explosive or other hazardous properties of any explosive nuclear assembly or nuclear component thereof;

16.1.5 strikes, boycotts, lock-outs, or other industrial disturbances or labour disputes (but not including any strike or slow down or obstructive or disruptive conduct or other labour disturbances restricted to that Seller or its Affiliates except, where the Affiliate is a Competent Authority [***];

16.1.6 loss of, accidental damage to, or inaccessibility to or inoperability of part or all of the FLNG Facility, the LNG Hub Facilities or the Future Facilities;

16.1.7 loss of, accidental damage to, or inaccessibility to or inoperability of part or all of the Upstream Facilities (including any variation and modifications to the Upstream Facilities made as part of the Future Facilities), to the extent that such loss of, accidental damage to, or inoperability is of a kind or character that, if it had happened to Seller Group, it would have come within the definition of Seller's Force Majeure;

16.1.8 depletion of the Reserves where depletion occurs for naturally-occurring geological, geophysical or tectonic reasons which are beyond the reasonable control of the Seller Group acting as a Reasonable and Prudent Operator and of which the Seller Group, acting as a Reasonable and Prudent Operator, was unaware on the Effective Date would adversely impact the Seller Group’s ability to perform its obligations hereunder;

16.1.9 Acts or omissions of a Competent Authority;

16.1.10 imposition of sanctions by any Sanctions Authority;

16.1.11 the withdrawal, denial or expiration of, or failure to obtain, any Authorisation;

16.1.12 any change in Law or International Standards after the Effective Date, or a change in the interpretation or application of existing Law after the Effective Date, that delays or prevents performance; and

16.1.13 any act, event or circumstance that affects a Third Party or Third Parties, including any subcontractor or agent with whom the Seller Group has contracted and/or upon whom it is relying in order to fulfil its obligations under this Agreement and that prevents, impedes or delays the Seller's performance under this Agreement, to the extent that it is of a kind or character that, if it had happened to that Seller, it would have come within the definition of Seller's Force Majeure.

16.2 **Buyer's Force Majeure**

The Buyer shall not be in breach of any of its obligations, or be liable for any delay or failure in performance, under this Agreement to the extent that its performance is prevented, impeded or delayed by an act, event or circumstance or combination of such acts, events or circumstances that are beyond the reasonable control of the Buyer acting as a Reasonable and Prudent Operator (**"Buyer's Force Majeure"**). Subject to the foregoing principles, Buyer's Force Majeure shall include, but not be limited to, the following acts, events and circumstances:

16.2.1 fire, explosion, flood, earthquake, lightning, storms, hurricanes, or other act of God or natural physical disaster or navigational or maritime peril;

16.2.2 acts of war (declared or undeclared), invasion, act of foreign enemies, hostilities, civil war, insurrection of military or usurped power;

16.2.3 terrorism, riot, rebellion, revolution, sabotage or civil unrest;

16.2.4 ionising radiations or contamination by radioactivity from any nuclear fuel or from any nuclear waste from the combustion of nuclear fuel, radioactive toxic explosive or other hazardous properties of any explosive nuclear assembly or nuclear component thereof;

16.2.5 strikes, boycotts, lock-outs, or other industrial disturbances or labour disputes (but not including any strike or slow down or obstructive or disruptive conduct or other labour disturbances restricted to the Buyer or its Affiliates);

16.2.6 loss of, accidental damage to, or inaccessibility to or inoperability of an Approved LNG Ship scheduled to load a Cargo at the LNG Hub Facilities within the then current Annual Delivery Programme or SDS or pursuant to Clause 5.3.4 provided that the Buyer’s Force Majeure shall only be considered to apply to the Cargoes to be transported by that Approved LNG Ship;

16.2.7 Acts or omissions of a Competent Authority;

16.2.8 imposition of sanctions by any Sanctions Authority;

16.2.9 the withdrawal, denial or expiration of, or failure to obtain, any Authorisation;

16.2.10 any change in Law or International Standards after the Effective Date or a change in the interpretation or application of existing Law after the Effective Date, that delays or prevents performance; and

16.2.11 any act, event or circumstance that affects a Third Party or Third Parties, including any subcontractor or agent with whom the Buyer has contracted and/or upon whom it is relying in order to fulfil its obligations under this Agreement and that prevents, impedes or delays the Buyer's performance under this Agreement, to the extent that it is of a kind or character that, if it had happened to the Buyer, it would have come within the definition of Buyer's Force Majeure.

16.3 **Events Not Force Majeure**

Notwithstanding Clauses 16.1 and 16.2 and the other terms of this Agreement, Force Majeure Events shall not include:

16.3.1 the non-availability or lack of funds or failure to pay money when due, except where such failure is caused by a failure of the systems of the relevant bank that prevents the Affected Party from performing its obligations;

16.3.2 financial hardship or the inability of a Party, and/or any Affiliate of a Party, to make a profit or achieve a satisfactory rate of return resulting from the performance or failure to perform its obligations under this Agreement or from the sale or consumption of LNG;

16.3.3 in the case of the Seller Group, any event or circumstance that does not prevent the development and production of Natural Gas in the Gas Supply Area, but merely renders such development and production more costly;

16.3.4 in the case of the Buyer, any event or circumstance that does not prevent the loading and the taking delivery of LNG but merely renders such loading and taking of delivery more costly (including loss of customers, loss of market share, or reduction in demand for LNG);

16.3.5 in the case of the Seller Group, depletion of the Gas Supply Area except where depletion occurs for naturally-occurring geological, geophysical or tectonic reasons which are beyond the reasonable control of the Sellers acting as a Reasonable and Prudent Operator and of which the Seller Group, acting as a Reasonable and Prudent Operator, was unaware on the Effective Date would adversely impact the Seller Group’s ability to perform its obligations hereunder;

16.3.6 import restrictions on LNG or Natural Gas imposed at any destination or proposed destination of LNG, or Natural Gas derived from LNG, sold or to be sold under this Agreement;

16.3.7 failure or inability to perform attributable to the applicable Contract Price or currency devaluation;

16.3.8 delays in the construction, completion, testing and start-up of the Upstream Facilities, FLNG Facility, the LNG Hub Facilities, the Future Facilities or the Approved LNG Ships unless the event or circumstance causing such delay would itself constitute a Force Majeure Event;

16.3.9 loss of, accidental damage to, or inaccessibility to or inoperability of the FLNG Facility, the LNG Hub Facilities, the Upstream Facilities or the Future Facilities to the extent such loss, damage, inaccessibility or inoperability is caused by:

(A) normal wear and tear;

(B) the failure to maintain such equipment to the standard of a Reasonable and Prudent Operator; or

(C) the failure to maintain such quantity of spare parts as would usually be expected to be maintained by a Reasonable and Prudent Operator.

16.3.10 loss of, accidental damage to, or inaccessibility to or inoperability of Approved LNG Ships to the extent such loss, damage, inaccessibility or inoperability is caused by:

(A) normal wear and tear;

(B) the failure to maintain such equipment to the standard of a Reasonable and Prudent Operator; or

(C) the failure to maintain such quantity of spare parts as would usually be expected to be maintained by a Reasonable and Prudent Operator;

16.3.11 in the case of the Buyer, any matter affecting any LNG unloading terminal or other facility owned or used by a customer or any other facility downstream of the foregoing unless such matter:

(A) [***]

(B) if the matter had impacted the Buyer would constitute a Buyer's Force Majeure;

(C) [***]

(D) in respect of such matter, the Buyer has fulfilled its obligations under Clauses 16.5 and 16.7 which for the purpose of this Clause 16.3.11, includes the Buyer seeking to unload at an alternate unloading terminal in a timely manner.

16.3.12 in respect of any Authorisations:

(A) any withdrawal, denial or expiration of, or failure to obtain, any Authorisation caused by the Affected Party's violation or breach of the terms and conditions of such Authorisation;

(B) any failure or delay in obtaining any Authorisation caused by the Affected Party's failure to apply for such Authorisation or a failure by the Affected Party to follow the necessary procedures to obtain such Authorisation;

(C) the terms of any Authorisation in effect as at the Effective Date;

16.3.13 any act or omission of a Competent Authority which is lawfully and validly taken by such Competent Authority:

(A) to the extent that such act or omission constitutes a remedy or sanction exercised as a result of a breach by the Affected Party of any Law in effect at the time of the breach;

(B) in the case of the Seller Group, solely and directly in respect of the exercise of any powers it holds as a shareholder, director or officer of a member of the Seller Group;

16.3.14 with respect to the Seller Group or a Seller, any act or omission of a Competent Authority which affects solely or primarily the Affected Party, which is discriminatory, and is not generally applicable to public and private entities doing business in the same country;

16.3.15 any failure to supply LNG sourced or to be sourced from a Future GTA Project until the Future Facilities Commercial Operations Date.

16.4 **Related Parties**

For the purposes of Clauses 16.1 and 16.2, an event shall not be considered to be beyond the reasonable control of a Party to this Agreement unless:

16.4.1 in the case of the Seller Group or a Seller, it is beyond the reasonable control of, and could not have been avoided by steps which might reasonably have been expected to have been taken by, the Seller Group, the Seller Group's Affiliates connected with the performance of this Agreement, the owner of the FLNG Facility, the FLNG Facility Operator, the FLNG Provider, the LNG Hub Facilities Operator, [***], in each case acting as a Reasonable and Prudent Operator in relation to the GTA Project or Future GTA Project; and

16.4.2 in the case of Buyer, it is beyond the reasonable control of, and could not have been avoided by steps which might reasonably have been expected to have been taken by, the Buyer, the Buyer's Affiliates connected with the performance of this Agreement or any Transporter, in either case acting as a Reasonable and Prudent Operator.

16.5 **Notification**

Any Party claiming to be relieved from its obligations under this Agreement on grounds of the occurrence of a Force Majeure Event (the **"Affected Party**") shall promptly give notice to the other Party (the "**Non-Affected Party**") of such act, event or circumstance promptly after the Affected Party has become aware of the occurrence of the act, event or circumstance and such notice shall include details of the nature of the Force Majeure, an estimate of the likely period of time required to overcome the impact of the Force Majeure (to the extent possible) and the Affected Party’s obligations under this Agreement that are affected by the Force Majeure Event (the “**FM Notice**”). Where such initial notice is not given in writing, it shall be confirmed by notice given as soon as practicable thereafter. Thereafter, such Party shall from time to time furnish to the other Party such relevant information as is available to it pertaining to such act, event or circumstance and the effect on the Upstream Facilities, FLNG Facility, Future Facilities or Approved LNG Ships, as the case may be, and shall give an estimate of the period of time required to overcome such act, event or circumstance and of the quantities of LNG that it reasonably expects to be able to make available, or take, as the case may be, during such period and shall notify the Non-Affected Party of:

(A) the particulars of the programme to be implemented and any corrective measures already taken to seek to ensure full resumption of normal performance;

(B) an estimate of the period of time required to overcome the impact of the Force Majeure Event;

(C) the quantities of LNG which it reasonably expects not to be able to make available, or take, as the case may be;

(D) the quantities of LNG which it reasonably expects to be able to make available, or take, as the case may be, during such period; and

(E) the corresponding impact on the Annual Delivery Programme or the most recent Specific Delivery Schedule (as the case may be).

The Affected Party shall promptly notify the Non-Affected Party in writing when it is once again able to perform its obligations under this Agreement.

16.6 **Impact of Force Majeure**

16.6.1 In the event of a Buyer's Force Majeure and either:

(A) the Arrival Window for any affected Cargo scheduled to be lifted by an Approved LNG Ship affected by Buyer’s Force Majeure, falls entirely within the period notified by the Buyer pursuant to Clause 16.5; or

(B) as a result of Buyer's Force Majeure:

(1) the Approved LNG Ship does not tender NOR by the end of the Arrival Window or within twenty-four (24) hours thereafter; or

(2) the Buyer fails to take delivery of all or any part of (i) the Commissioning Cargo Quantity notified in accordance with Clause 5.3.4 or (i**i) the Scheduled Loading Quantity, as applicable, within** [***] after the Permitted Time, provided that where a Notice of Readiness is tendered within [***] after the end of the Arrival Window, such [***]period (after the Permitted Time) shall be reduced by *“x”*, where, for the purpose of this clause, *“x”* means the number of hours after the end of the Arrival Window that the Notice of Readiness is tendered,

the Seller Group shall have the right to cancel such Cargo (or such portion thereof) in compliance with prevailing safety restrictions and shall be excused of the obligation to make such Cargo (or portion thereof) available to the Buyer and may sell or otherwise dispose of such Cargo (or such portion thereof) for the Seller Group’s own account, without restriction. Without affecting the foregoing sentence, if the Buyer subsequently notifies a shorter period to the Seller Group pursuant to Clause 16.5 then the Buyer shall promptly give notice of the revised date that the Buyer will be ready to resume performance of the affected obligations and the Seller Group shall, within five (5) days of receipt of such notice, notify the Buyer whether the Seller Group wishes, in its sole discretion, the Buyer to resume performance of the relevant obligations on the notified ready date or any date on or before the originally notified end date of the period of time required to overcome the impact of such Buyer's Force Majeure. If the Seller Group does not elect to resume performance of the relevant obligations on the notified ready date, the Buyer’s Force Majeure shall continue until the notified end date or the earlier date elected by the Seller Group.

(C) The [***] period in Clause 16.6.1(B)(1) and the [***] period after the Permitted Time in Clause 16.6.1(B)(2) shall become [***] on and after the Future Facilities Commercial Operations Date.

16.6.2 In the event of a Seller's Force Majeure and either:

(A) the Arrival Window for any affected Cargo falls entirely within the period notified by the Seller Group pursuant to Clause 16.5; or

(B) as a result of Seller's Force Majeure, the Seller Group is unable to make available all or a portion of a Cargo within [***] after Permitted Time,

the Buyer shall have the right to cancel such Cargo (or such portion thereof) in compliance with prevailing safety restrictions and shall be excused of the obligation to take delivery of such Cargo (or portion thereof) and if despite the Seller's Force Majeure under Clause 9.3.10(B) and Clause 9.4.6 a Cargo can still be loaded, Seller Group may sell or otherwise dispose of such Cargo (or such portion thereof) for the Seller Group's own account, without restriction. Without affecting the foregoing sentence, if the Seller Group subsequently notifies a shorter period to the Buyer pursuant to Clause 16.5 then the Seller Group shall promptly give notice of the revised date that the Seller Group will be ready to resume performance of the affected obligations and the Buyer shall, within five (5) days of receipt of such notice, notify the Seller Group whether the Buyer wishes, in its sole discretion, the Seller Group to resume performance of the relevant obligations on the notified ready date or any date on or before the originally notified end date of the period of time required to overcome the impact of such Seller's Force Majeure. If the Buyer elects not to resume performance of the relevant obligations on the notified ready date, the Seller's Force Majeure shall continue until the notified end date or the earlier date elected by the Buyer. The Seller Group may sell or otherwise dispose of Cargoes (or such portion thereof) available between the notified ready date and the date on or before the notified end date elected by Buyer for the Seller Group's own account, without restriction.

The twenty-four (hour) period in Clause 16.6.2(B) shall become six (6) hours on and after the Future Facilities Commercial Operations Date.

16.6.3 In the event of a Seller's Force Majeure in respect of the GTA Project and a Future GTA Project that is not excluded under Clause 16.3.15 (or either), the Seller Group shall allocate available LNG from the GTA Project and Future GTA Project among the Buyer and Firm LNG Buyers. Such allocation shall be on a pro rata basis (to the extent reasonably practicable) in proportion to the firm amounts of LNG which Buyer and such Firm LNG Buyers are committed to take. The Seller Group shall provide the Buyer with the calculations and supporting documentation used in determining the proration during any such period.

16.6.4 Prior to the Future Facilities Commercial Operations Date, the Buyer shall have priority in the event of a Seller's Force Majeure on all available volumes from the GTA Project so as to fulfil the Seller Group's obligations under this Agreement.

16.6.5 [***]

(A) [***]

(B) [***]

16.7 Obligations Following a Force Majeure Event

16.7.1 To the extent a Party is entitled to relief from its obligations under this Agreement on grounds of the occurrence of a Force Majeure Event, such Party shall, as soon as reasonably possible, take the measures that a Reasonable and Prudent Operator would take (including applying the proceeds of any relevant insurance policy to the remedy or rectification of the consequences of such Force Majeure Event) to bring the Force Majeure Event to an end and to overcome and/or minimise the effects and consequences thereof that prevent, impede or delay such Party's ability to resume performance under this Agreement.

16.7.2 An Affected Party shall:

(A) notify the other Party of the steps it proposes to take to minimise the effects of such Force Majeure Event, including any reasonable alternative means for performance and, to the extent that they are not prejudiced in so doing, the other Party shall use reasonable endeavours to co-operate in taking such steps; and

(B) at the request of the other Party, use reasonable endeavours to give or procure access (at the expense and risk of the Party seeking access) at all reasonable times for a reasonable number of representatives of such other Party to examine the scene of such Force Majeure Event.

16.7.3 Without prejudice to the provisions of Clause 16.7.1 and Clause 16.7.2, prior to resumption of normal performance, the Parties shall continue to perform their obligations under this Agreement to the extent not excused by the occurrence of such Force Majeure Event.

16.8 **Termination for Prolonged Force Majeure**

16.8.1 If:

(A) Seller's Force Majeure results in a delay to the Commercial Operations Date [***] then the Buyer may, in its sole discretion, terminate this Agreement by and upon giving [***] written notice to the other Party; or

(B) If at any time during the Contract Term an event or events of Seller's Force Majeure or Buyer’s Force Majeure has been continuing [***].

16.8.2 The provisions of Clauses 22.6.7 and 22.7 shall apply in respect of any termination pursuant to this Clause 16.8.

17. LIABILITIES

17.1 **Consequential Loss**

17.1.1 Without prejudice to the remedies listed under Clause 17.5, a Party and its Representatives will have no liability to any other Party or such other Party’s Representatives (on the basis of breach of contract, indemnity, warranty or tort, including negligence and strict or absolute liability, or breach of statutory duty or otherwise) for or in respect of any matter arising in the course of or in connection with this Agreement in respect of:

(A) any indirect or consequential loss or damages;

(B) any lost or increased production costs, loss or deferral of income, profit, revenue, use, goodwill, contract or business opportunity;

(C) any business interruption;

(D) any exemplary or punitive damages;

(E) the payment or repayment of any amounts (or any acceleration thereof) to lenders or creditors of the Parties from time to time;

(F) any claim, demand or action made or brought against the other Party by a Third Party,

(together called **"Consequential Loss"**) as a result of any act or omission in the course of or in connection with the performance of this Agreement, whether or not the Seller Group or the Buyer knew (or ought to have known) as of the Effective Date or the date that a relevant breach of the terms of this Agreement took place that any of the matters described in Clause 17.1.1 (A) to (F) would be likely to be suffered or incurred as a result of the relevant act or omission.

17.1.2 Each Party undertakes not to institute any proceedings or make any claim against the other Party or its Affiliates and the directors, officers and employees of such Party or its Affiliates in respect of such Consequential Loss.

17.2 **Conditions of Use**

As between (i) any Transporter and the master of any Approved LNG Ship and (ii) the LNG Hub Facilities Operator, liability in respect of damage to or loss of the LNG Hub Facilities, FLNG Facility, Approved LNG Ships and any other property; injury to or death of their respective personnel; and any other matters addressed by the Conditions of Use, shall be allocated in accordance with the Conditions of Use and, with respect to matters covered by the COU the Buyer and the Seller Group (or any Seller) shall have no liability to each other under this Agreement (in such capacity) in respect of such matters. Nothing in this Clause 17.2 shall be deemed to modify the allocation of liability in Clause 8.2.

17.3 **Liability as Between Seller Group and Buyer for Third Party claims**

17.3.1 Subject to Clause 17.3.2, as between the Parties the liability for any claim, demand or action made or brought against a Party by a Third Party in connection with the performance of this Agreement shall be determined and borne between the Parties in accordance with Clause 23.6.

17.3.2 Where a claim is made or brought against a Party ("**the first Party**") by a Third Party which relates to an ABC Law Violation by another Party ("**the second Party**") then the liability of the second Party to the first Party shall be determined in accordance with Clause 25.9.

17.4 **Mitigation of Loss**

A Party establishing or alleging a breach of contract or a right to be indemnified in accordance with this Agreement shall take all necessary measures to mitigate the loss that has or may occur, provided that it can do so without unreasonable inconvenience or unreasonable cost.

17.5 **Exclusive Remedies**

The Seller Group and the Buyer agree that notwithstanding Clause 17.1, the remedies set out expressly Clauses 5.3.1, 5.3.8, 5.3.9. 7.4, 7.5, 7.6, 9.12.5, 9.13.2, 10.1.11, 10.1.13 and 14 shall be the sole and exclusive remedies of the Seller Group and the Buyer for the matters referred to therein.

18. SAFETY, SECURITY AND ENVIRONMENT

18.1 Reasonable and Prudent Operators

The Seller Group and the Buyer recognise the importance of securing and maintaining safety, security and environmental protection in all matters contemplated in this Agreement including the construction and operation of their respective facilities and also including transportation of LNG and shall, acting as Reasonable and Prudent Operators, secure and maintain high standards of safety, security and environmental protection in accordance with the internationally accepted best practice prevailing in the LNG industry from time to time in a diligent, safe and efficient manner.

18.2 Safe Performance of Works and Services

The Seller Group and the Buyer shall procure that their respective employees, agents, contractors and suppliers shall have due regard to safety, security and environmental protection and abide by relevant regulations and internationally accepted best practice prevailing in the LNG industry from time to time while they are performing works and services within the LNG Hub Facilities and on board the FLNG Facility, the Future Facilities or an Approved LNG Ship.

19. IMPLEMENTATION PROCEDURES AND EXCHANGE OF INFORMATION

19.1 Implementation Procedures

As soon as reasonably practicable but not later than twelve (12) months prior to the last day of the Target Period, the Buyer and the Seller Group shall agree, whether as a protocol to this Agreement or as a separate document, a set of procedures for the purpose of assisting the Parties in the administration of this Agreement. Such implementation procedures shall cover, inter alia:

19.1.1 the various procedures, reports and calculation tools as will be necessary to properly implement this Agreement;

19.1.2 the specific line items and details to be included in each Quarterly Statement and Annual Statement; and

19.1.3 the documentation for any other forms and notices required under this Agreement.

19.2 General

Subject to any contractual obligations of confidentiality under any other agreement to which Seller Group or Buyer is a party, Seller Group and Buyer shall maintain close communication and mutually provide and exchange available information directly relevant to the fulfilment of the terms and conditions of this Agreement.

19.3 Audit

19.3.1 Each Party shall have the right, on at least thirty (30) days advance notice to the other Party, to request a certificate from an independent Third Party auditor with no conflict of interest, reasonably acceptable to the other Party, confirming that any costs, expenses, damages and liabilities charged by the other Party pursuant to this Agreement are accurately stated and reflect, as a matter of fact, the requirements of this Agreement. It shall not be within the scope of the auditor's task under this Clause

19.3.1 to verify whether any component of the relevant amount or calculation complies with any requirement of reasonableness applicable under this Agreement or to assess whether the audited Party has complied with any obligation to use reasonable endeavours.

19.3.2 The audited Party shall provide the auditor (but not the Party that requested the audit certificate) with all relevant documentation and information at its disposal for these purposes together with any documentation reasonably requested by the auditor to verify that, without limitation, the loss, cost or expense has in fact been suffered. The auditor's costs for the preparation of such certificate shall be borne by the Party that requested the audit certificate.

19.3.3 A Party appointing an auditor under this Clause 19.3 shall ensure that the auditor enters into a confidentiality undertaking substantially similar to that set out in Clause 21.

20. FUTURE IMPLEMENTATION

20.1 Future GTA Project

20.1.1 Nothing in this Agreement shall restrict the Seller Group's right to carry out the Future Facilities Implementation Works. If the Seller Group intends to carry out Future Facilities Implementation Works, it shall inform the Buyer of the Scheduled Implementation Works Suspension Quantity in accordance with Clause 7.1.2.

20.1.2 The Seller Group acknowledges that it intends to develop Future Facilities, including the provision of additional storage, provided that any final investment decision for any Future GTA Project shall be at the sole discretion of the Seller Group.

20.1.3 [***]

21. CONFIDENTIALITY

21.1 Confidential Information

The terms of this Agreement and any information disclosed by any Party to the others (whether orally or in writing or in some other permanent form) in connection with this Agreement (including the nature or progress of any discussion or negotiations relating to this Agreement and all documents and information prepared or generated by the Parties from such disclosed information) which is not already known to the recipient from sources other than the other Party, or not independently developed by the recipient or its Affiliate, or not already in the public domain (other than as a result of a breach of the terms of this Clause 21.1) (**"Confidential Information"**) shall, unless otherwise agreed in writing by the disclosing Party, be kept confidential and shall not be used other than for a purpose connected with this Agreement or, save as provided below, disclosed to Third Parties by the receiving Party.

21.2 Permitted Disclosures

21.2.1 The Confidential Information, that either Party receives from the other may, subject to Clause 21.2.2, be disclosed by such Party:

(A) to any other Party;

(B) to any Person who is legal counsel, other professional consultant or adviser to that Party in relation to matters contemplated under or in connection with this Agreement, to the extent that their role requires them to have access to the

Confidential Information, in each case in connection with the GTA Project and/or Future GTA Project;

(C) to any Person who is an insurer, accountant, underwriter or provider of finance or financial support (including any bank, lending agency, export credit agency, funding agency, insurance agency or similar institution in relation to that finance, or to advisers or consultants to any such bank, agency or institution) to that Party, including efforts by the Seller Group or one or more of the Sellers or an Affiliate of one or more of the Sellers to obtain funds or project financing, or to document any loan to or security granted by the Seller Group or one or more of the Sellers or an Affiliate of one or more of the Sellers;

(D) if required and to the extent required by the rules of any recognised stock exchange or agency established in connection therewith with which such Party is bound to comply;

(E) if required and to the extent required by any applicable Law, or by a Competent Authority, or such Party becomes legally required to disclose such information, *provided* that such Party shall, to the extent practicable, give prior notice to the other Party of the requirement and the terms thereof and will furnish only that portion of such information that it is legally required to furnish; [***];

(F) to any of its Affiliates or shareholders (or any company involved in the provision of advice to any such shareholder for the purposes of this Agreement) and any employee, officer, agent and/or contractor of such Affiliates or shareholders to which disclosure is permitted pursuant to this Clause 21.2.1(E), to the extent that their role requires them to have access to the Confidential Information;

(G) in the case of SMHPM to the Ministries and other Competent Authorities of the Government of Mauritania in accordance with their internal procedures;

(H) in the case of PETROSEN to the Ministries and other Competent Authorities of the Government of Senegal in accordance with their internal procedures;

(I) to a bona fide purchaser or proposed bona fide purchaser of any or all of the shares in any Party;

(J) with the prior written consent of the Party to which the Confidential Information relates;

(K) to a bona fide Transferee or proposed bona fide Transferee of an Upstream Participating Interest;

(L) disclosed to the extent required to vest the full benefit of this Agreement to a bona fide party to whom assignment is permitted under Clause 24;

(M) in order to enable a determination by an arbitral tribunal or Expert to be made under Clause 23 or the enforcement of any such determination;

(N) in respect of the Seller Group, to the LNG Hub Facilities Operator and providers of Marine Services to the extent reasonably required to facilitate the performance of its responsibilities in connection with this Agreement;

(O) in respect of the Buyer, to the Transporter, to its counterparties under any resale arrangements and providers of Marine Services to the extent reasonably required to facilitate the performance of its responsibilities in connection with this Agreement , and persons to whom disclosure is required under Clause 24.3; and

(P) to the extent it is already in the public domain (other than as a result of a breach by the relevant Party or its Representative of the terms of this Clause 21).

21.2.2 A Party making any disclosure pursuant to Clause 21.2.1 shall ensure that any Person listed in Clause 21.2.1(B) (excluding its legal counsel who have a professional obligation of confidentiality), (C), (I), (J), (K), (L), (M), (N), or (O) to which it discloses Confidential Information undertakes to hold such Confidential Information subject to confidentiality obligations equivalent to those set out in Clause 21.2.1. In the case of a disclosure to in accordance with Clause 21.2.1(F), (i) the Party making the disclosure shall ensure that each recipient has been informed of the confidential nature of the Confidential Information, and (ii) in respect of a disclosure to a company involved in the provision of advice to a shareholder for the purposes of this Agreement, such company shall be required to hold such Confidential Information subject to confidentiality obligations equivalent to those set out in Clause 21.2.1.

21.2.3 If a Party wishes to issue or make any public announcement, press release or statement regarding this Agreement, it shall, prior to the release of the public announcement, press release or statement, furnish the other Parties with a copy of such announcement, press release or statement with as much prior notice as is reasonably practicable in the prevailing circumstances and obtain the prior written approval of the other Parties, such consent not to be unreasonably withheld, conditioned or delayed. Notwithstanding any failure to obtain such approval, no Party shall be prohibited from issuing or making any such public announcement, press release or statement if it is necessary to do so in order to comply with applicable Laws or the directives, rules or regulations of any government, legal proceeding or stock exchange having jurisdiction over such Party or its Affiliates.

21.2.4 Permitted Releases. Notwithstanding any provision in this Clause 21 to the contrary, any Party may use the following in external announcements, presentations and publications:

(A)information concerning the signing of this Agreement; and

(B)information concerning the general nature of this Agreement;

<u>provided that</u> the Party making such external announcement or publication shall not use the trademark, service mark and trade name of the other Party without such other Party's prior written consent.

21.3 **Duration of Confidentiality**

The foregoing obligations with regard to the Confidential Information shall remain in effect for [***].

22. **DEFAULT AND TERMINATION**

22.1 **Buyer Events of Default**

Each of the following shall constitute an event of default in respect of the Buyer (each a **"Buyer Event of Default"**):

22.1.1 the Buyer or the Buyer's Acceptable Credit Support Provider fails to pay any amount or amounts due from the Buyer under this Agreement that, in aggregate (but excluding amounts which have been disputed pursuant to Clause 12.5), is in excess of [***] due from it (whether under one or more outstanding invoices), and such payment default is not cured by the Buyer or its Acceptable Credit Support Provider within [***] of the Seller Group notifying the Buyer of such payment default;

22.1.2 the Buyer fails to provide and maintain the Acceptable Credit Support in accordance with Clause 12.7;

22.1.3 the Buyer fails to take a quantity of LNG equal to at least [***] of the ACQ, for reasons other than Force Majeure or the failure of the Seller Group or Persons referred to in Clause 7.4.1(E), [***];

22.1.4 [***]

22.1.5 the Buyer is in breach of any of its obligations under Clause 25.9 and/or Clause 25.10; or

22.1.6 a Buyer Insolvency Event occurs.

22.2 **Seller Group Events of Default**

Each of the following shall constitute an event of default in respect of the Seller Group (each a **"Seller Group Event of Default"**):

22.2.1 the Seller Group fails to pay by way of a credit any amount or amounts due from the Seller Group under this Agreement that, in aggregate (but excluding amounts which have been disputed pursuant to Clause 12.5), is in excess of [***] due from it (whether under one or more outstanding invoices) at the time and in the manner stipulated herein by the respective due date and such payment default is not cured by the Seller Group within [***] of the Buyer notifying the Seller Group of such payment default;

22.2.2 the UUOA ceases to be in full force and effect as a result of the actions or omissions of the Seller Group, save to the extent such fault constituted an act and/or omission undertaken or not undertaken, as the case may be, with the prior written consent of the Buyer; and

22.2.3 a termination event occurs under [***].

22.3 **Seller Events of Default**

Each of the following shall constitute an event of default in respect of an individual Seller (each a **"Seller Event of Default"**):

22.3.1 without prejudice to the Seller Group's obligation to apply credits for amounts due to the Buyer under Clause 12.3.2, a Seller fails to pay any amount or amounts due from the Seller under this Agreement that, in aggregate (but excluding amounts which have been disputed pursuant to Clause 12.5), is in excess of a sum equal to [***] multiplied by that Seller's LNG SPA Participation due from it (whether under one or more outstanding invoices) at the time and in the manner stipulated herein by the respective due date and such payment default is not cured by the Seller within [***] of the Buyer notifying the Seller of such payment default;

22.3.2 a warranty given pursuant to Clause 8.4 is untrue when given;

22.3.3 a Seller Insolvency Event occurs;

22.3.4 a Seller is in breach of any of its obligations under Clause 25.9 and/or Clause 25.10, by and upon giving immediate notice to the Seller;

22.3.5 a termination event occurs [***];

22.3.6 a Seller fails to make available a quantity of LNG equal to at least [***] of its LNG SPA Participation share of the ACQ, for reasons other than Force Majeure or the failure of the Buyer or the Transporter [***].

22.3.7 a Seller Transfers all or part of its Upstream Participating Interest and fails to transfer its corresponding LNG SPA Participation when required by, and in accordance with, Clause 3;

22.3.8 a Seller Transfers all or part of its LNG SPA Participation and fails to transfer its corresponding Upstream Participating Interest when required by, and in accordance with, Clause 3;

22.3.9 [***]

22.3.10 [***]

22.3.11 [***]

22.3.12 [***]

22.4 **Suspension by the Seller Group**

22.4.1 If a Buyer's Event of Default occurs, the Seller Group or a Seller shall be entitled to suspend performance of its obligations to make available LNG under this Agreement upon giving [***] prior written notice to the Buyer (or in case of a Buyer's Event of Default under Clause 22.1.5, immediately) until such Buyer's Event of Default has been remedied by, and written notice of such remedy has been received from, the Buyer.

22.4.2 As soon as such notice of remedy has been received from the Buyer, the Seller Group or a Seller shall resume deliveries of LNG to the Buyer in accordance with this Agreement as soon as it is reasonably practicable to do so, and in any event within [***] days after the date of receipt of such notice. In such case, the Seller Group or the Seller shall not be deemed to have failed to make any part of the AACQ available as to any such suspended quantities (and, for the avoidance of doubt, the provisions of Clause 7.6 shall not apply nor shall such suspended Quantities form part of the Cargo Deliver or Pay Quantity). The Seller Group or the Seller shall be deemed to have made available Cargoes in respect of which delivery is suspended pursuant to this Clause 22.4 and, accordingly, the Scheduled Loading Quantity for each such Cargo shall constitute a Cargo Take or Pay Quantity, <u>provided that</u> no portion of any such Cargo with a Arrival Window beginning on or after the day following the date on which such Buyer's Event of Default has been remedied by, and written notice of such remedy has been received from, the Buyer, shall constitute a Cargo Take or Pay Quantity.

22.4.3 The Seller Group or a Seller shall not be entitled to suspend its obligations pursuant to Clause 22.4.1 with respect to any Buyer's Event of Default arising under Clause 22.1.2 if, for any Cargo, the Buyer makes advance payment for such Cargo, on terms and conditions acceptable to the Seller Group or the Seller (acting reasonably).

22.4.4 During any period of suspension of deliveries to the Buyer pursuant to Clause 22.4, the Seller Group may sell or otherwise dispose of, for the Seller Group's own account, without restriction, all LNG produced by the GTA Project.

22.5 **Suspension by the Buyer**

22.5.1 If a Seller Group Event of Default or a Seller Event of Default occurs, the Buyer shall be entitled to suspend performance of its obligations to take LNG under this Agreement upon giving [***] days' prior written notice to the Seller Group (or in case of a Seller Event of Default under Clause 22.3.4, immediately) until such Seller Group's Event of Default or Seller Event of Default has been remedied by, and written notice of such remedy has been received from, the Seller Group or the applicable Seller provided that such suspension shall not be effective if the Seller Group's Event of Default or Seller Event of Default has been remedied by the Seller Group or relevant Seller within such [***] day period (including, in respect of a Seller Event of Default, if, at the option of the remaining members of the Seller Group, (i) any or all of the remaining members of the

Seller Group (in such proportions as they may agree between them) acquire, or any other Person acquires, pursuant to this Agreement the LNG SPA Participation of the Seller which is the subject of the Seller Event of Default and remedy the default of the defaulting Seller under this Agreement, or (ii) any or all of the remaining members of the Seller Group (in such proportions as they may agree between them) otherwise remedy the default of the defaulting Seller under this Agreement).

22.5.2 As soon as such notice of remedy has been received from the Seller Group or the applicable Seller, the Buyer shall resume taking deliveries of LNG from the Seller Group or the applicable Seller in accordance with this Agreement as soon as it is reasonably practicable to do so, and in any event within [***] after the date of receipt of such notice. In such case, the Buyer shall not be deemed to have failed to take any part of the AACQ as to any such suspended quantities (and, for the avoidance of doubt, the provisions of Clause 7.4 shall not apply nor shall such suspended Quantities form part of the Cargo Take or Pay Quantity). The Buyer shall be deemed to have taken delivery of Cargoes in respect of which delivery is suspended pursuant to this Clause 22.5 and, accordingly, the Scheduled Loading Quantity for each such Cargo shall constitute a Cargo Deliver or Pay Quantity, provided that no portion of any such Cargo with a Arrival Window beginning on or after the day following the date on which such Seller Group Event of Default or Seller Event of Default has been remedied by, and written notice of such remedy has been received from, the Seller Group or the applicable Seller, shall constitute a Cargo Deliver or Pay Quantity.

22.6 **Termination Right**

22.6.1 For the purposes hereof:

(A) the **"Defaulting Party"** is (i) the Seller Group in relation to the events specified in Clause 22.2, (ii) the applicable Seller in relation to the events specified in Clause 22.3, and (iii) the Buyer in relation to the events specified in Clause 22.1; and

(B) the **"Non-Defaulting Party"** is the Buyer in relation to the events specified in Clauses 22.2 and 22.3 and the Seller Group in relation to the events specified in Clause 22.1.

22.6.2 The Buyer shall have the right to terminate this Agreement (solely in respect of the Defaulting Party in respect of a Seller Event of Default, and in respect of the Seller Group as a whole in respect of a Seller Group Event of Default):

(A) if a Seller Group's Event of Default or Seller Event of Default has occurred, except as provided for in Clause 22.6.2(B), by and upon giving not less than [***] written notice to the Seller Group while such Seller Group's Event of Default or Seller Event of Default subsists, provided that such termination shall not be effective if the Seller Group's Event of Default or Seller Event of Default has been remedied by the Seller Group or relevant Seller within such [***] period (including, in respect of a Seller Event of Default, at the option of the remaining members of the Seller Group, if (i) any or all of the remaining members of the Seller Group (in such proportions as they may agree between them) acquire, or any other Person acquires pursuant to this Agreement the LNG SPA Participation of the Seller which is the subject of the Seller Event of Default) and remedy the default of the defaulting Seller under this Agreement, or (ii) any or all of the remaining members of the Seller Group (in such proportions as they may agree between them) otherwise meet the obligations of the defaulting Seller under this Agreement). The Buyer shall be entitled to withdraw its notice to terminate this Agreement at any time during such [***] period;

(B) in respect of a Seller who is in breach of any of its obligations under Clauses 22.2.3, 22.3.2, 25.9 or 25.10 or in respect of the Seller Group if a Seller Group Event of Default occurs pursuant to Clause 22.2.3 and/or 22.3.6, by and upon giving immediate notice to the Seller Group.

22.6.3 If the Buyer terminates this Agreement in respect of a Seller under Clause 22.6.2(A) or (B):

(A) [***]

(B) [***]

22.6.4 The Seller Group shall have the right to terminate this Agreement (or a Seller shall have a right to terminate its LNG SPA Participation of this Agreement):

(A) if a Buyer Event of Default has occurred, except as provided for in Clause 22.6.4(B), by and upon giving not less than [***] written notice to the Buyer while such Buyer Event of Default subsists, provided that such termination shall not be effective if the relevant Buyer Event of Default has been remedied by the Buyer within such [***] period. The Seller Group or the Seller shall be entitled to withdraw its notice to terminate this Agreement at any time during such [***] day period;

(B) if the Buyer is in breach of any of its obligations under Clauses 25.9 and 25.10 or there is a Buyer Event of Default pursuant to Clause 22.1.3, by and upon giving immediate notice to the Buyer.

(C) [***]

22.6.5 [***]

22.6.6 [***]

22.6.7 Termination of this Agreement shall be without prejudice to the rights, obligations and liabilities of the Parties accrued prior to the date on which such termination takes effect, including in respect of antecedent breaches. The obligations of each Party which are expressed to survive termination or take effect on termination shall continue in full force and effect notwithstanding termination of this Agreement.

22.6.8 Except as otherwise set out in Clause 16.8 and this Clause 22 a Party shall have no right to terminate this Agreement, whether at common law or otherwise.

22.7 **Survival**

Termination of this Agreement shall be without prejudice to the rights or remedies of the Parties accrued prior to or as a result of such termination and the Parties agree that Clauses 1, 12, 13, 17, 21 (to the extent provided therein), 23, 25 and 26 shall, in addition to this Clause 22.7, survive the expiration or termination of this Agreement for the period necessary for the exercise of any such rights or remedies.

22.8 The thresholds in the definitions of “Buyer Event of Default”, “Seller Group Event of Default” and “Seller Event of Default” are solely for the purpose of determining the rights of the Parties to take the measures set forth in this Clause 22. Such thresholds do not limit the obligations of any Party hereunder or the rights of any other Party to enforce such obligations or to make any claim in respect of or breach of such obligations.

23. DISPUTE SETTLEMENT AND GOVERNING LAW

23.1 **Dispute Resolution**

23.1.1 If the Seller Group, any Seller or the Buyer wishes to submit a Dispute for resolution they shall commence the dispute resolution process by providing the other with written notice of the Dispute (a "**Notice of Dispute**").

23.1.2 The Parties shall attempt to resolve any Dispute by amicable negotiation within thirty (30) days of a Notice of Dispute being given by a Party. If the Dispute is not resolved within thirty (30) days from the date of the Notice of Dispute (or such longer period as may be agreed by the Parties), and the Dispute has not been referred for resolution by an Expert under Clause 23.3, either Party may refer the Dispute to arbitration pursuant to Clause 23.2.

23.2 **Arbitration**

23.2.1 Any dispute, controversy or claim arising out of or in connection with this Agreement or its subject matter or formation, including any dispute regarding its existence, formation, validity, enforceability, interpretation, performance, breach, operations carried out under it or its termination, and whether based in contract, tort, statute, regulation or otherwise or any dispute regarding any non-contractual obligations arising out of or in connection with it (a **"Dispute"**), that the Buyer and the Seller Group or Seller do not otherwise resolve between themselves pursuant to Clause 23.1.2 or agree to refer for expert determination in accordance with Clause 23.3, shall be referred to and finally resolved by arbitration under the [***] effective at the time of the commencement of the arbitration (the "**Rules**"), which Rules are deemed to be incorporated by reference into this Clause 23.2, and the terms of this Clause 23.2, by sending a written request for arbitration to the [***] and by sending copy to the other Party simultaneously. If the [***] are in conflict with this Clause 23.2, including the provisions concerning the appointment of arbitrators, the provisions of this Clause 23.2 shall prevail, except where a provision of the[***] is non-waivable under the terms of the [***].

23.2.2 The place and legal seat of the arbitration shall be [***].

23.2.3 The arbitral tribunal shall consist of three arbitrators. Within thirty (30) Days of the written request for arbitration, the claimant(s), irrespective of number, shall nominate jointly one arbitrator and the respondent(s), irrespective of number, shall nominate jointly the second arbitrator. The third arbitrator (who, subject to confirmation by [***], shall act as President of the arbitral tribunal) shall be appointed by the arbitrators nominated by the claimant(s) and respondent(s) or, in the absence of agreement on the third arbitrator within fifteen (15) days of the nomination of the second arbitrator, by the [***] in accordance with the [***]. If claimant(s) and/or respondent(s) fail to nominate an arbitrator, an arbitrator shall be appointed on their behalf by the [***]in accordance with the [***]). In such circumstances, any existing nomination or confirmation of an arbitrator shall be unaffected, and the remaining arbitrator(s) shall be appointed in accordance with this Clause 23.2.3. If an arbitrator fails or is unable to act, his successor will be appointed in the same manner as the arbitrator whom he succeeds. The decision of a majority of the arbitrators shall be final and binding upon the Parties. Each arbitrator shall remain impartial and independent of the Parties involved in the arbitration.

23.2.4 The language to be used in the arbitration shall be English and the arbitrators shall be fluent in English. Notwithstanding the preceding sentence, any Person (other than an arbitrator) participating in the arbitration may speak in French or another language with the assistance of a translator. All statements of claim or defence, briefs, procedural orders, and awards, and the reasons supporting them, shall be in English, but shall be accompanied by a French translation. In the event of any conflict or inconsistency between the English version and the French translation, the English version shall prevail.

23.2.5 The law of the arbitration agreement shall be [***].

23.2.6 This agreement to arbitrate shall be binding upon the Parties, their successors and assigns.

23.2.7 The Parties agree to exclude any right to appeal any question of law [***].

23.2.8 Rights granted to Third Party indemnitees under this Agreement shall be enforced by such Third Parties by arbitration in accordance with this Clause 23.2. Where a claim is brought against a Third Party by a Party in response to which a Third Party wishes to rely on any right or defence afforded to it under this Agreement, such Third Party shall have the option to choose that the Dispute be finally settled by arbitration in accordance with this Clause 23.2 provided such option is exercised by notice in writing to all Parties within seven (7) days of being notified of the claim by any Party.

23.2.9 The arbitral tribunal shall have full authority to grant provisional remedies, including remedies requiring the furnishing of security or guarantees and remedies requiring the preservation of anything or right under the control of a Party to the arbitration, and to award damages for the failure of any Party to respect the arbitral tribunal's orders to that effect.

23.2.10 Any monetary award shall be made and promptly payable in U.S. Dollars free of any Tax, deduction or offset, and the arbitral tribunal shall be authorised in its discretion to grant pre-award and post-award interest at commercial rates from the date of any breach until the date any award is paid in full including interest due. Any costs, fees or Taxes incidental to enforcing the award shall, to the maximum extent permitted by applicable Law, be charged against the Party against whom such enforcement is sought. The arbitral tribunal shall have the authority to award any remedy or relief proposed by the claimant(s) or respondent(s), including a declaratory judgment, specific performance of any obligation created under this Agreement or the issuance of an injunction, provided that the arbitral tribunal is prohibited from awarding punitive damages.

23.2.11 Legal professional privilege, including privileges protecting attorney-client communications and attorney work product of each Party from compelled disclosure or use in evidence, legal advice privilege and litigation privilege, as recognized by the laws governing each Party's relationship with its counsel, shall apply to and be binding in any arbitration proceeding conducted under this Clause 23.2.11.

23.2.12 Except to the extent necessary to enforce the arbitration agreement or award, to enforce other rights of the Parties hereunder, or as required by applicable Law or the rules of any stock exchange on which the shares of any Party or any of its Affiliates are listed or are in the process of being listed, or as otherwise permitted under Clause 21, the Parties, their Affiliates, and all of their employees, officers, directors, counsel, consultants, and expert witnesses, shall maintain as confidential the fact of the arbitration proceedings, the arbitral award, filings or submissions exchanged or produced during the arbitration proceedings, and briefs or other documents prepared in connection with the arbitration.

23.2.13 In the event of default by any Party in respect of any procedural order made by the arbitrators, the arbitrators shall have the power to proceed with the arbitration and to deliver an award in the absence of the Party.

23.2.14 The arbitrators shall make the award and any other decisions or rulings strictly according to Law and not *ex aequo et bono* or as *amiable compositeur*.

23.2.15 All notices by the Parties in connection with any arbitration shall be in accordance with Clause 26.

23.2.16 Any award rendered by the arbitrators hereunder shall be final and binding upon the Parties as from the date rendered Judgment upon any award may be entered in any court having jurisdiction thereof.

23.3 Settlement by Expert

23.3.1 A Dispute may be referred to an Expert if it is referred to expert determination pursuant to the applicable Clause or if the Seller Group and the Buyer agree in writing that, in view of the nature of that Dispute, the Dispute is more suitable for expert determination. Any Dispute referred to an Expert shall be referred and resolved as follows:

(A) either the Buyer or the Seller Group may refer such Dispute to an Expert (which expression shall include a panel of Experts if the Parties so agree) by proposing in writing the appointment of an Expert;

(B) the Parties shall jointly appoint the Expert by agreement, or failing such agreement within twenty-one (21) days of the Parties agreement to submit such Dispute to an Expert, by the [***] in accordance with the [***] on the application of either Party;

(C) the language to be used for the determination of the Dispute shall be English unless otherwise agreed provided that any person (other than the Expert) participating in the Expert determination may speak in French or another language with the assistance of a translator;

(D) the Parties shall notify the Expert of his or her selection and the proposed terms of appointment. Such terms shall include a covenant from the Expert that such Expert will not during the term of the appointment accept any duty, or acquire or agree to acquire any interest, that may materially conflict with the Expert's function under such appointment.

(E) the Expert appointed shall be, and shall remain, independent of all Parties and shall act impartially. Any Person appointed as an Expert shall before accepting such appointment fully disclose any interest or duty he has or may have which conflicts with his function under such appointment, and he shall also fully disclose any such interest or duty incurred at any time before he gives his determination under such appointment, provided that no Person shall be appointed an Expert who at the time of appointment is or has at any time during the twenty (20) years prior to the time of appointment been an employee of or consultant to any Party or of any Affiliate of any Party or of any company in which any Party has a financial interest;

(F) if the Expert has been appointed but is unable or unwilling to complete the reference, another Expert shall be appointed by agreement between the Seller Group and the Buyer or, failing agreement within fourteen (14) days of the Parties being notified that the Expert is unable or unwilling to complete the reference, by the [***] in accordance with the [***] on the application of either Party;

(G) the Expert shall act as an expert and not as an arbitrator or mediator;

(H) the Seller Group and the Buyer shall have the right to make representations and submissions to the Expert, to be provided to the Expert within fourteen (14) days of the date of the appointment of the Expert. There will be no formal hearing;

(I) the Seller Group and the Buyer shall make all relevant documents and information within their control available to the Expert, subject to any obligations of confidentiality;

(J) the Seller Group and the Buyer shall request that the Expert determine the referred Dispute and provide a decision in writing within thirty (30) days of receiving the reference;

(K) any decision of the Expert shall, in the absence of fraud, manifest error or breach by the Expert of his or her covenant referred to in Clause 23.3.1(D) be final and binding upon the Parties. Any such challenge pursuant to the previous sentence to the Expert's determination must be made within thirty (30) days of the issuance of the Expert's decision, and shall be deemed a Dispute and shall be resolved pursuant to clause 23.1;

(L) the procedure by which the Expert reaches his or her determination shall not be, and such determination itself shall not be, appealable or subject to, challenge, whether under any applicable arbitration statute or otherwise, except in instances of manifest error, fraud or breach by the Expert of his or her covenant referred to in Clause 23.3.1(D); and

(M) the costs and expenses of the Expert shall [***], except as may be otherwise provided herein.

23.4 **Costs and Expenses**

23.4.1 Unless otherwise determined in a final arbitration award or by the Expert, each party shall bear the costs of its own lawyers, witnesses, experts and other assisting persons it may utilise for any arbitration proceeding under Clause 23.

23.4.2 Unless otherwise determined in a final arbitration award or by the Expert, the cost of the venue of any arbitration under this Clause 23 and the fees of the arbitration tribunal shall, together with any Expert fees incurred under Clause 23.3, [***].

23.5 **Immunity**

23.5.1 Each Party, as to itself and its assets, hereby irrevocably, unconditionally, knowingly and intentionally waives the benefit of any right of immunity (sovereign or otherwise) and agrees not to claim or assert any immunity with respect to the matters covered by or arising out of or in connection with this Agreement in any arbitration, Expert proceeding or other action with respect to this Agreement, whether arising by statute or otherwise, that it may have or may subsequently acquire, including rights under the doctrines of sovereign immunity and act of state, immunity from legal process (including service of process or notice, pre-judgment or pre-award attachment, attachment in aid of execution, or otherwise), immunity from jurisdiction or judgment of any court, arbitrator, Expert or tribunal (including any objection or claim on the basis of inconvenient forum), and immunity from enforcement or execution of any award or judgment or any other remedy.

23.5.2 Each Party irrevocably and unconditionally:

(A) acknowledges and agrees that the execution and performance by it of this Agreement constitute private and commercial acts rather than public or governmental acts; and

(B) consents in respect of the enforcement of any judgment against it in any such proceedings in any jurisdiction and to the giving of any relief or the issue of any process in connection with such proceedings (including the making, enforcement or execution of any such judgment or any order arising out of any such judgment against or in respect of any property whatsoever irrespective of its use or intended use).

23.5.3 For the avoidance of doubt, any reference to any assets of a Party in this Article shall mean those assets to which such Party has right, title and/or interest. The Parties accept and recognize that:

(A) PETROSEN's assets do not include the share of the State as defined in the St-Louis PSC, the share of the Republic of Senegal pursuant to any other hydrocarbon exploration and production sharing contract or any other assets, interests or entitlements of the Republic of Senegal or of any of its agencies, authorities or manifestations (except for the avoidance of doubt the assets, interests and entitlements of PETROSEN itself); and

(B) SMHPM's assets do not include the share of the State as defined in the Block C8 PSC, the share of the Islamic Republic of Mauritania pursuant to any other exploration and production sharing contract or any other assets, interests or entitlements of the Islamic Republic of Mauritania or of any of its agencies, authorities or manifestations (except for the avoidance of doubt the assets, interests and entitlements of SMHPM itself).

23.6 **Governing Law**

This Agreement and any dispute or claim arising out of or in connection with it or its subject matter or formation (including non-contractual disputes or claims) shall be governed by and construed [***], without reference to any choice or conflict of law principle that would result in the application of any other law. [***].

24. ASSIGNMENT

24.1 **Generally**

Subject to Clause 3.1.3, Clause 22.6.3 and Clause 24.2, no Party may, without the prior written consent of the Buyer (in the case of an assignment by a Seller) or each Seller (in the case of an assignment by Buyer) (such consent not to be unreasonably withheld or delayed), assign or transfer to any Person any benefit or obligation under this Agreement, in whole or in part, absolutely or conditionally, provided that any novation or assignment of its rights and/or obligations under this Agreement by a Party is only permitted if:

(A) in the case of Buyer,

(i) [***]

(ii) [***]

(B) in the case of Buyer and Seller, such assignee assumes all of the obligations of the assigning Party under this Agreement commencing as of the date of the assignment by execution of a copy of this Agreement in its own name (countersigned by the non-assigning Party) or by execution of a binding assignment and assumption agreement which is enforceable by the non-assigning Party.

[***]

24.2 **Permitted Assignees**

24.2.1 Notwithstanding Clause 24.1, any Party may novate or assign all of its rights and obligations under this Agreement to an Affiliate, provided that:

(A) such Affiliate has the legal capacity, the financial capacity and the technical capability (directly or indirectly through its Affiliates) to perform the obligations to be assigned;

(B) where the Buyer is the assigning Party, it shall remain liable to maintain the Buyer Guarantee required in accordance with Clause 12.7 and ensure the continued validity of any letter of credit issued on its behalf in accordance with Clause 12.7;

(C) the assigning Party shall remain liable under this Agreement for the performance of all of its obligations, including those assigned to the Affiliate;

(D) performance of this Agreement with such Affiliate assignee would comply with applicable Laws and all relevant Authorisations;

(E) if such Affiliate of the assigning Party, following such assignment, ceases at any time to be an Affiliate of the assigning Party, all rights and obligations of such Affiliate under this Agreement shall be automatically re-assigned to the assigning Party;

(F) following such assignment, the assigning Party shall not Transfer any of its Upstream Participating Interest to any Third Party unless and until such Affiliate has reassigned to the assigning Party all of its rights and obligations hereunder; and

(G) such Affiliate may not in turn assign any or all of such rights and obligations to any Party except to the assigning Party.

24.2.2 Notwithstanding Clause 24.1, any Transferring Seller may novate or assign all or any part of its rights and obligations under this Agreement to any Person to whom it Transfers all or a corresponding part of its Upstream Participating Interest or all or any part of its rights under this Agreement to another Seller as may be required by the terms of other agreements among the Seller Group, provided that the Transferring Seller complies with the terms of Clauses 3.1.3, and 3.1.4.

24.2.3 Clause 24.1 shall be without prejudice to Clause 3.1.6.

24.2.4 Any assignee or transferee shall be subject to the other Party's reasonable know-your-customer process.

24.3 [***]

24.3.1 [***]

24.3.2 [***]

(A) [***]

(B) [***]

(C) [***]

(D) agreement by the Buyer not to terminate or cancel this Agreement without the lenders being given a right to cure the default giving rise to the Buyer's right to cancel or terminate within the cure period referred to in (B) above;

(E) agreement that the Buyer shall make payments due under this Agreement to an account or accounts specified from time to time by the lenders or their agent or trustee on the condition that such payment will be good discharge of the relevant obligations of the Buyer to the Sellers under this Agreement; and

(F) agreement that, without prejudice to the Buyer's other rights under this Agreement, the Buyer consents to the lenders appointing a substitute Third Party, subject to the terms of Clauses 3.1.3, 3.1.4, and 3.1.5, to assume the rights and obligations of Seller Group or a Seller (as applicable) following enforcement of the lenders' security and shall not terminate this Agreement solely due to assumption by that Third Party, at the direction of the lenders, of some or all of the rights and obligations of the Seller Group or any Seller under this Agreement.

24.3.3 If the Seller Group or one or more of the Sellers elects to seek project financing in respect of the GTA Project or a Future GTA Project, the Parties agree to work together in good faith (and the Seller Group (or applicable Sellers) shall reimburse all the reasonable transactional costs (including travel and associated costs) of Buyer in connection therewith), to address the reasonable requirements of the lenders with respect to the terms of this Agreement, but without any obligation on either Party to accept any such requirements.

24.3.4 The Seller Group's obligations to apply credits and the Buyer's rights to set-off amounts in accordance with Clause 12.3 shall be unaffected by the direct agreement or consent to an assignment by way of security in favour of a lender or lenders.

24.3.5 In respect of the above provisions, the Buyer shall carry out its customary know-your-customer process on all Persons with which it deals pursuant to this Clause 24.

25. MISCELLANEOUS

25.1 Disclaimer of Agency

Nothing in this Agreement nor any other agreement or arrangement of which it forms part, nor the performance by the Parties of their respective obligations under any such agreement or arrangement, shall constitute a partnership between the Parties. Save as expressly provided in this Agreement, this Agreement does not constitute any Party as the agent, partner or legal representative of the other Party for any purposes whatsoever, and no Party shall have any express or implied right or authority (unless expressly conferred in writing under this Agreement or otherwise and not revoked) to assume or to create any obligations or responsibility on behalf of or in the name of the other Party as its agent or otherwise.

25.2 Entire Agreement

This Agreement, together with the Schedules and Exhibits hereto, constitutes the entire agreement between the Parties with respect to the subject matter contemplated by this Agreement and supersedes any prior or contemporaneous written or oral agreement between them with respect to such subject matter, including specifically [***].

25.3 Reliance

Each Party acknowledges that it has not been induced to enter into this Agreement by any representation, warranty or undertaking not expressly incorporated into this Agreement. So far as permitted by Law and except in the case of fraud, each Party agrees and acknowledges that its only rights and remedies in relation to any representation, warranty or undertaking made or given in connection with this Agreement shall be for breach of the terms of this Agreement, to the exclusion of all other rights and remedies (including those in tort or arising under statute). In this Clause, "this Agreement" includes all documents entered into pursuant to this Agreement

25.4 **Third Party Beneficiaries**

25.4.1 Except for the provisions of Clauses 3.3.6 and 17.1, this Agreement is intended solely for the benefit of the Seller Group and the Buyer, and the Parties do not intend any term of this Agreement to be for the benefit of or enforceable by any Person who is not a Party to this Agreement and no term of this Agreement shall be enforceable under the Contracts (Rights of Third Parties) Act 1999 by any Person who is not a Party to this Agreement.

25.4.2 The Parties may rescind or vary this Agreement, in whole or in part, without the consent of any Third Party.

25.5 **Variation**

No amendment, change, modification or variation of this Agreement shall be effective unless in writing and signed by or on behalf of each Party and approved by the Ministers.

25.6 **Waiver**

No failure to exercise, nor any delay in exercising, any right, power or remedy under this Agreement shall operate as a waiver, nor shall any single or partial exercise of any right or remedy prevent any further or other exercise or the exercise of any other right or remedy. Any waiver of any breach of this Agreement shall not be deemed to be a waiver of any subsequent breach. Any waiver of any breach of this Agreement shall be in writing signed by the waiving Party.

25.7 **Counterparts**

This Agreement and any instrument amending this Agreement may be executed in any number of counterparts and this has the same effect as if the signatures on the counterparts were on a single copy of the Agreement.

25.8 **Severability**

25.8.1 Except as may otherwise be stated herein, if at any time any provision or part of a provision of this Agreement is declared or rendered illegal, invalid, unlawful or unenforceable by any Competent Authority, or deemed unlawful because of a statutory change, that provision or part of a provision shall be deemed to be deleted from this Agreement and the remaining provisions will not, in any way, be affected or impaired.

25.8.2 The Parties will negotiate in good faith with a view to agreeing one or more valid and enforceable provisions which may be substituted for any such invalid, illegal or unenforceable provision or part of a provision to ensure as nearly as is practicable in all the circumstances that the appropriate balance of the commercial interests of the Parties under this Agreement is preserved. No failure to agree upon such provisions shall be susceptible to dispute resolution pursuant to Clause 23.

25.9 **Compliance with ABC Law**

25.9.1 Each Party represents and warrants (as a continuing representation and warranty repeated each day for the duration of this Agreement) and undertakes to the other that in connection with this Agreement or any activities contemplated by it, neither it nor any of its Representatives:

(A) has offered, authorised, promised, given, solicited or accepted or received nor shall offer, authorise, promise, give, solicit or accept or receive, to or from any Person, directly or indirectly, any payment, gift, service, thing of value or other advantage where such payment, gift, service, thing of value or other advantage would be an ABC Law Violation; nor

(B) has received nor will receive any commission, fee, rebate, gift or entertainment of significant cost or value without prior written notification to the other Party.

25.9.2 Each Party shall (and shall ensure that its Representatives shall) with respect to or in connection with this Agreement or any activities contemplated by it:

(A) comply with ABC Laws; and

(B) not commit an ABC Law Violation.

25.9.3 In particular, each Party represents, warrants and undertakes to the other that it shall not, and shall ensure that its Representatives shall not, directly or indirectly:

(A) pay, promise to pay, authorise the payment of, give, offer, accept or agree to accept, any monies or other things of value to or from a Person or a Competent Authority; or

(B) engage in other acts or transactions,

in each case if this represents a violation of or is inconsistent with ABC Law.

25.9.4 Each Party must immediately notify the other Party of any ABC Law Violation.

25.9.5 If either Party asserts that the other Party is not in compliance with Clause 25.9.1 or 25.9.2, the Party asserting non-compliance shall send a notice to the other Party indicating the type of non-compliance asserted and providing supporting evidence and documentation.

25.9.6 No Party is authorised to take any action on behalf of another Party that would result in an inadequate or inaccurate recording and reporting of assets, liabilities, or any other transaction, or which would put such other Party in violation of its obligations under any law applicable to this Agreement and its contemplated activities.

25.10 **Trade controls and Sanctions**

25.10.1 Each Party:

(A) represents and warrants (as a continuing representation and warranty repeated each day for the duration of this Agreement) that neither it nor any Person or entity that owns or controls it is a restricted party on a Sanctions List or is subject to any Trade Sanctions that may apply to the subject matter of this Agreement and its contemplated activities;

(B) agrees to comply with any Trade Sanctions and with any anti-money laundering and anti-terrorism laws applicable to the subject matter of this Agreement and its contemplated activities, provided that with respect to Trade Sanctions adopted by the States of Mauritania or Senegal, compliance by the Buyer shall be subject to the Buyer first having received written notification of such Trade Sanctions from the Seller Group or from the Competent Authorities in the States of Mauritania or Senegal, as applicable; and

(C) agrees to comply with all export and trade control laws, regulations, and orders applicable to the export, re-export, transfer, import sale or use of the LNG sold under this Agreement.

25.10.2 If a Party reasonably believes that the other Party has breached or will be in breach of Clause 25.10.1 or that, as a result thereof, continuing to perform this Agreement would cause it to act in a manner which would likely put it in breach of Clause 25.10.1, then:

(A) it may notify the other Party requiring the other Party to provide all information reasonably required to verify whether the other Party is in compliance with Clause 25.10.1; and

(B) the other Party must provide that information to it.

25.10.3 None of the language in this Agreement is intended, or shall be construed, to require either Party to take or refrain from taking any action in connection with the subject matter of this Agreement and its contemplated activities that:

(A) would be in violation of applicable Trade Sanctions;

(B) would be penalised under the anti-boycott laws and regulations or (to the extent that this does not contravene any applicable law) secondary sanctions laws of the United States of America; or

(C) would place the other Party or its Affiliates in a position of non-compliance with the foregoing laws or any ABC Law.

25.10.4 Nothing in this Clause 25.10 shall require SMHPM to comply with any Trade Sanctions that might be applied against the Islamic Republic of Mauritania or to require PETROSEN to comply with any Trade Sanctions that might be applied against the Republic of Senegal.

26. NOTICES

26.1 Form of Notice

Any notice or other communication, including invoices, from the Buyer to the Seller Group or from the Seller Group to the Buyer (or, where contemplated in this Agreement, from or to the LNG Hub Facilities Operator, Transporter or the master of the Approved LNG Ship), which is required or permitted to be made by the provisions of this Agreement shall be:

26.1.1 made in the English language;

26.1.2 made in writing;

26.1.3 delivered by email or by hand or sent by courier to the address of the Buyer or the Seller Group (as applicable) which is shown below or to such other address as Buyer or the Seller Group shall by notice require, or sent to such other e-mail address as the Buyer or the Seller Group (as applicable) shall by notice require.

26.1.4 marked for the attention of the Person(s) there referred to or to such other Person(s) as the other Party shall by notice require.

The addresses of the Parties for service of notices are as follows:

For notices to the Buyer:

[***]

For notices to the Seller Group:

Seller Group's Representative: [***]

[***] [***]

For notices to an individual Seller:

SMHPM:
[***]

PETROSEN:
[***]

BPMIL:
[***]

BPSIL:
[***]

KEM:
[***]

KEISL:
[***]

26.1.5 The Buyer or the Seller Group (as applicable) may change the address, e-mail address or Person to whom the notice or communication shall be served by providing not less than seven (7) days' written notice thereof to the Buyer or the Seller Group (as applicable).

26.2 **Effective Time of Notice**

26.2.1 Any notice, invoice or other communication made by one Party to the other Party in accordance with the foregoing provisions of this Clause 26 shall be deemed to be received by the other Party if delivered by hand or by courier, on the day on which it is received at that Party's address, or if sent by e-mail on the next day on which the office of the receiving Party is normally open for business; provided always that operational notices pursuant to Clause 9 sent by email shall be deemed to be received immediately after their transmission. The receiving Party shall be obligated to transmit a manual (not automatic) written acknowledgement of successful receipt (which may be transmitted electronically) which the receiving Party shall furnish promptly after successful receipt.

REMAINDER OF PAGE INTENTIONALLY LEFT BLANK

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their respective duly authorised representative as of the day and year first above written.

For and on behalf of

LA SOCIETE MAURITANIENNE DES HYDROCARBURES ET DE PATRIMOINE MINIER

By: /s/ Tourad Abdel Baghi

Name: Tourad Abdel Baghi

Title: Director General

For and on behalf of

BP MAURITANIA INVESTMENTS LIMITED

By: /s/ Norman Christie

Name: Norman Christie

Title:

For and on behalf of

KOSMOS ENERGY MAURITANIA

By: /s/ Todd Niebruegge

Name: Todd Niebruegge

Title: Vice President

For and on behalf of

LA SOCIETE DES PÉTROLES DU SENEGAL

By: /s/ Mamadou Faye

Name: Mamadou Faye

Title: Director General

For and on behalf of

BP SENEGAL INVESTMENTS LIMITED

By: /s/ Norman Christie

Name: Norman Christie

Title:

For and on behalf of

KOSMOS ENERGY INVESTMENTS SENEGAL LIMITED

By: /s/ Todd Niebruegge

Name: Todd Niebruegge

Title: Vice President

For and on behalf of

BP GAS MARKETING LIMITED

By: /s/ Robert J. Harrison

Name: Robert J. Harrison

Title: Director

Following execution of this Agreement by all the Parties hereto, this Agreement will be effective on the date (the "**Effective Date**") when approved by the two States. The States mean:

THE ISLAMIC REPUBLIC OF MAURITANIA, represented for the purposes of these presents by the Minister of Petroleum Mines and Energy; and
THE REPUBLIC OF SENEGAL represented for the purposes of these presents by the Minister of Petroleum and Energies.

IN WITNESS of their approval, the Ministers or their authorised representatives have approved this Agreement for the term of the Agreement on the date indicated below. [***]

For the Islamic Republic of Mauritania, by the Minister of Petroleum Mines and Energy	For the Republic of Senegal, by the Minister of Petroleum and Energies
By: /s/ Mohamed Abdel Vetah__________	By: /s/ Mouhamadou Makhtar Cisse_______
Mohamed Abdel Vetah _______________	Mouhamadou Makhtar Cisse____________
(Printed name)	(Printed name)
Date:11 February 2020_________________	Date:11 February 2020_________________

KOSMOS ENERGY

November 12, 2019

Ronald Glass
In person

Re: Promotion

Dear Ronald,

Congratulations! I am pleased to offer you a promotion from Controller to VP and CAO, effective November 16, 2019.

Your new annual pay is $290,000 and your annual bonus target will increase from 40% to 50%.

Your new annual pay will continue to be paid on a semi-monthly basis and you will report directly to Neal Shah, SVP and Deputy CFO, in this position.

All other terms and conditions of employment will remain unchanged.

Ronald, you are a valuable part of our team. Thank you for your contribution to Kosmos and congratulations on the promotion.

Please let me know if you have any questions.

Sincerely,

Neal Shah
SVP and Deputy CFO

cc: Human Resources

Exhibit 21.1

List of Subsidiaries

Subsidiary	**Jurisdiction of Incorporation**
Kosmos Energy Ltd.	Delaware
Kosmos Energy Delaware Holdings, LLC	Delaware
Kosmos Energy Holdings	Cayman Islands
Kosmos Energy LLC	Texas
Kosmos Energy Operating	Cayman Islands
Kosmos Energy Ventures	Cayman Islands
Kosmos Energy South Atlantic	Cayman Islands
Kosmos Energy Latin America	Cayman Islands
Kosmos Energy Brasil Oleo e Gas Ltda.	Brazil
Kosmos Energy Deepwater Morocco	Cayman Islands
Kosmos Energy Cameroon HC	Cayman Islands
Kosmos Energy Offshore Morocco HC	Cayman Islands
Kosmos Energy Finance International	Cayman Islands
Kosmos Energy Finance	Cayman Islands
Kosmos Energy International	Cayman Islands
Kosmos Energy Development	Cayman Islands
Kosmos Energy Ghana HC	Cayman Islands
Kosmos Energy Suriname	Cayman Islands
Kosmos Energy Ireland	Cayman Islands
Kosmos Energy Mauritania	Cayman Islands
Kosmos Energy Venture Holdings	Cayman Islands
Kosmos Energy Equatorial Guinea	Cayman Islands
Kosmos Energy Credit International	Cayman Islands
FATE Energy Services	Cayman Islands
Kosmos Energy Operating Service SARL	Morocco
Kosmos Energy Liberia	Cayman Islands
Kosmos Energy Portugal	Cayman Islands
Kosmos Energy Senegal	Cayman Islands
Kosmos Energy Global Supply	Cayman Islands
Kosmos Energy Sao Tome and Principe	Cayman Islands
Kosmos Energy Sao Tome and Principe Block 4	Cayman Islands
Kosmos Energy Maroc Mer Profonde	Cayman Islands
Kosmos Energy Congo	Cayman Islands
Kosmos Energy Cote d'Ivoire	Cayman Islands
Kosmos Energy Namibia	Cayman Islands
Kosmos Energy GOM Holdings, LLC	United States of America
Kosmos Energy Gulf of Mexico, LLC	United States of America
Kosmos Energy Gulf of Mexico Management, LLC	United States of America
Kosmos Energy Gulf of Mexico Operations, LLC	United States of America
Houston Energy Deepwater Ventures	United States of America
Kosmos Energy Investments Senegal Limited	United Kingdom
Kosmos International Petroleum, Inc.	Cayman Islands
Kosmos Equatorial Guinea, Inc.	Cayman Islands
Kosmos Energy South Africa Limited	United Kingdom
Kosmos Energy Tortue Finance	Cayman Islands
Kosmos Energy Ghana UK Limited	United Kingdom

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statements (Form S-8, No. 333-174234, Form S-8, No. 333-207259 and Form S-8, No. 333-228397) pertaining to the Kosmos Energy Ltd. Long Term Incentive Plan and the Registration Statement (Form S-3 No. 333-227084) of Kosmos Energy Ltd. and in the related Prospectus of our reports dated February 24, 2020, with respect to the consolidated financial statements and schedules and the effectiveness of internal control over financial reporting of Kosmos Energy Ltd., included in this Annual Report (Form 10-K) for the year ended December 31, 2019.

/s/ ERNST &YOUNG LLP

Dallas, Texas
February 24, 2020

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE REGISTERED ENGINEERING FIRM F-1580
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294
FAX (713) 651-0849
TELEPHONE (713) 651-9191

EXHIBIT 23.2

February 20, 2020

Mr. Paul Tooms
Kosmos Energy, LLC
8176 Park Lane, Suite 500
Dallas, Texas 75231

We hereby consent to (1) the reference of our firm and to the use of our reports of the Greater Jubilee, TEN, Ceiba, Okume, and Gulf of Mexico Project Area effective December 31, 2019 and dated January 22, 2020, and the Greater Tortue Project Area effective January 31, 2020 and dated February 12, 2020 in the Kosmos Energy Ltd. Annual Report on Form 10-K for the year ended December 31, 2019, to be filed with the U.S. Securities Exchange Commission on or about February 20, 2020; and (2) the incorporation by reference of our reports of the Greater Jubilee, TEN, Ceiba, Okume, and Gulf of Mexico Project Area effective December 31, 2019 and dated January 22, 2020, and the Greater Tortue Project Area effective January 31, 2020 and dated February 12, 2020 in the Kosmos Energy Ltd. Registration Statements (Form S-8, No. 333-174234, Form S-8, No. 333-207259 and Form S-8, No. 333-228397) and Registration Statement (Form S-3, No. 333-227084) and in any related prospectus, including any reference to our firm under the heading “Experts” in such prospectus.

/s/ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Exhibit 31.1

Certification of Chief Executive Officer

I, Andrew G. Inglis, certify that:

1. I have reviewed this annual report on Form 10-K of Kosmos Energy Ltd.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent function):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 24, 2020

/s/ Andrew G. Inglis

Andrew G. Inglis
Chairman of the Board of Directors and
Chief Executive Officer (Principal Executive Officer)

Exhibit 31.2

Certification of Chief Financial Officer

I, Thomas P. Chambers, certify that:

1. I have reviewed this annual report on Form 10-K of Kosmos Energy Ltd.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2020

/s/ Thomas P. Chambers

Thomas P. Chambers
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32.1

Certification of Chief Executive Officer
Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the accompanying annual report of Kosmos Energy Ltd. (the "Company") on Form 10-K for the period ended December 31, 2019, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Andrew G. Inglis, Chairman of the Board of Directors and Chief Executive Officer of the Company, hereby certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 24, 2020

/s/ Andrew G. Inglis

Andrew G. Inglis
Chairman of the Board of Directors and Chief Executive Officer
(Principal Executive Officer)

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

Certification of Chief Financial Officer
Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the annual report of Kosmos Energy Ltd. (the "Company") on Form 10-K for the period ended December 31, 2019, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Thomas P. Chambers, Senior Vice President and Chief Financial Officer of the Company, hereby certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 24, 2020	/s/ Thomas P. Chambers
	Thomas P. Chambers *Senior Vice President and Chief Financial Officer* *(Principal Financial Officer)*

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 99.1

KOSMOS ENERGY LIMITED

Estimated

Future Reserves and Income

Attributable to Certain Interests

Proved Reserves

SEC Parameters

As of

December 31, 2019

\s\ Tosin Famurewa
Tosin Famurewa, P.E., S.P.E.C.
TBPE License No. 100569
Managing Senior Vice President

[SEAL]

\s\ Christine E. Neylon
Christine E. Neylon, P.E.
TBPE License No. 122128
Vice President

\s\ Victor Abu
Victor Abu, P.E.
TBPE License No. 132717
Vice President

[SEAL] **[SEAL]**

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

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RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE REGISTERED ENGINEERING FIRM F-1580
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294
FAX (713) 651-0849
TELEPHONE (713) 651-9191

January 22, 2020

Kosmos Energy Limited
8176 Park Lane, Suite 500
Dallas, Texas 75231

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain interests of Kosmos Energy Limited (Kosmos) as of December 31, 2019. The subject properties are located in Ghana, offshore West Africa, in the West Cape Three Points (WCTP) and Deep Water Tano (DWT) blocks, hereafter referred to as the “Greater Jubilee and TEN Project Areas,” Equatorial Guinea, offshore Central Africa, in the G and F blocks, hereafter referred to as the “Ceiba and Okume Project Areas” and United States of America, federal waters offshore Louisiana and Texas, hereafter referred to as the “Gulf of Mexico Project Area.” The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 17, 2020 and presented herein, was prepared for public disclosure by Kosmos in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott in this report represent 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of Kosmos as of December 31, 2019.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2019, are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. At Kosmos’ request, we have included estimated gross (100%) reserves, along with the estimated net reserves and income data. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Gross Reserves* Data
Derived Through Certain Interests of
Kosmos Energy Limited
As of December 31, 2019

	Proved			
	Developed			
	Producing	Non-Producing	Undeveloped	Total
Gulf of Mexico Project Area				
Gross Reserves				
Oil/Condensate – Mbbl	123,220	13,178	33,120	169,518
Plant Products – MBOE	11,675	2,865	6,158	20,698
Produced Gas – MMcf	135,494	32,277	70,463	238,234
Fuel Gas – MMcf	0	0	0	0
Greater Jubilee and TEN Project Areas				
Gross Reserves				
Oil/Condensate – Mbbl	238,683	0	206,798	445,481
Plant Products – MBOE	0	0	0	0
Produced Gas – MMcf	1,086,138	0	290,976	1,377,114
Fuel Gas – MMcf	90,573	0	0	90,573
Ceiba and Okume Project Areas				
Gross Reserves				
Oil/Condensate – Mbbl	57,765	12,401	9,982	80,148
Plant Products – MBOE	0	0	0	0
Produced Gas – MMcf	34,424	7,082	5,694	47,200
Fuel Gas – MMcf	28,495	0	0	28,495
Total				
Gross Reserves				
Oil/Condensate – Mbbl	419,668	25,579	249,900	695,147
Plant Products – MBOE	11,675	2,865	6,158	20,698
Produced Gas – MMcf	1,256,056	39,359	367,133	1,662,548
Fuel Gas – MMcf	119,068	0	0	119,068

**These volumes are 100% gross and do not represent net volumes to Kosmos' interests. Net reserves and income are shown below.*

SEC PARAMETERS
Estimated Net Reserves and Income Data
Derived Through Certain Interests of
Kosmos Energy Limited
As of December 31, 2019

	Proved			
	Developed			
	Producing**	Non-Producing	Undeveloped	Total
Gulf of Mexico Project Area				
Net Reserves				
Oil/Condensate – Mbbl	27,588	3,494	4,802	35,884
Plant Products – MBOE	2,416	372	736	3,524
Sales Gas – MMcf	24,218	3,570	7,294	35,082
Fuel Gas – MMcf	0	0	0	0
Income Data ($M)				
Future Gross Revenue	$1,683,648	$218,232	$302,869	$2,204,749
Deductions	446,810	67,412	189,851	704,073
Future Net Income (FNI)	$1,236,838	$150,820	$113,018	$1,500,676
Discounted FNI @ 10%	$1,070,152	$ 61,577	$ 52,110	$1,183,839
Greater Jubilee and TEN Project Areas				
Net Reserves				
Oil/Condensate – Mbbl	47,252	0	40,700	87,952
Plant Products – MBOE	0	0	0	0
Sales Gas – MMcf	12,868	0	13,883	26,751
Fuel Gas – MMcf	17,729	0	0	17,729
Income Data ($M)				
Future Gross Revenue	$2,992,521	$0	$2,578,259	$5,570,780
Deductions	1,045,142	0	1,379,520	2,424,662
Future Net Income (FNI)	$1,947,379	$0	$1,198,739	$3,146,118
Discounted FNI @ 10%	$1,451,959	$0	$ 668,703	$2,120,662

Ceiba and Okume Project Areas				
Net Reserves				
Oil/Condensate – Mbbl	18,725	4,038	3,308	26,071
Plant Products – MBOE	0	0	0	0
Sales Gas – MMcf	0	0	0	0
Fuel Gas – MMcf	12,110	0	0	12,110
Income Data ($M)				
Future Gross Revenue	$1,181,926	$254,859	$208,777	$1,645,562
Deductions	793,397	168,436	111,447	1,073,280
Future Net Income (FNI)	$ 388,529	$ 86,423	$ 97,330	$ 572,282
Discounted FNI @ 10%	$ 355,169	$ 90,515	$ 77,924	$ 523,608
Total				
Net Reserves				
Oil/Condensate – Mbbl	93,565	7,532	48,810	149,907
Plant Products – MBOE	2,416	372	736	3,524
Sales Gas – MMcf	37,086	3,570	21,177	61,833
Fuel Gas – MMcf	29,839	0	0	29,839
Income Data ($M)				
Future Gross Revenue	$5,858,095	$473,091	$3,089,905	$9,421,091
Deductions	2,285,349	235,848	1,680,818	4,202,015
Future Net Income (FNI)	$3,572,746	$237,243	$1,409,087	$5,219,076
Discounted FNI @ 10%	$2,877,280	$152,092	$ 798,737	$3,828,109

***Includes proved depleted summary consisting of certain P&A liability costs*

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). Fuel gas volumes are attributed to those volumes of gas that are consumed for fuel in field operations, while sales gas volumes are reported on an “as sold basis.” Kosmos elected not to report fuel gas for the Gulf of Mexico Project Area. All gas volumes are expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package PHDWin Petroleum Economic Evaluation Software, a copyrighted program of TRC Consultants L.C. and economic models developed in Microsoft EXCEL. These programs were used at the request of Kosmos. Ryder Scott has found these programs to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The deductions incorporate the normal direct costs of operating the wells, recompletion costs, development costs, and certain abandonment costs net of salvage. Deductions in the Greater Jubilee and TEN project areas include Additional Oil Entitlements (“AOE”). AOE is a contractual mechanism that prevents the contractor group from collecting “windfall profits” and is treated herein as a deduction to the future gross revenue; however, for the Greater Jubilee and TEN Project Areas our economic analysis indicates there are no AOE deductions for the proved reserves. The AOE calculation is determined at the block level and includes a rate of return calculation that is derived on an after corporate income tax basis based on interpretations of tax considerations made by Kosmos. In the Greater Jubilee and TEN Project Areas, abandonment costs (included in the “Development Costs” column of the cash flow projections) are triggered and escrowed several years before the economic limit is reached, and this may result in negative FNI values for certain years prior to abandonment.

Certain gas, oil and condensate processing and handling fees, including compression fees where applicable are included as “Other” and “Ad Valorem Taxes” deductions in the cash flows. The later are not true ad valorem taxes but represent Kosmos’ throughput fee to Talos for processing and handling of the production volumes from the Tornado field in the Gulf of Mexico Project Area. The separate tracking of this throughput fee in the “Ad Valorem Taxes” column of the cash flows was done at Kosmos’ request.

There are no production taxes associated with the Greater Jubilee, TEN, Ceiba, Okume and Gulf of Mexico Project Areas. The future net income is before the deductions of U.S. state and federal or foreign income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist, nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for approximately 99.2 percent and gas reserves account for the remaining 0.8 percent of the total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded annually. Future net income was discounted at four other discount rates which were also compounded annually. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2019
Discount Rate Percent	Total Proved
5	$4,425,234
15	$3,367,892
20	$3,005,430
25	$2,714,445

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission’s Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled “PETROLEUM RESERVES DEFINITIONS” is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled “PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES” in this report. The proved developed non-producing reserves included herein consist of the shut-in and behind-pipe status categories.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist.

Reserves are “estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.” All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves, and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Kosmos’ request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are “those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward.” The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a “high degree of confidence that the quantities will be recovered.”

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that “as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.” Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

The proved reserves reported herein are limited to the period prior to expiration of current contracts providing the legal rights to produce, or a revenue interest in such production unless evidence indicates that contract renewal is reasonably certain. Furthermore, the subject properties located in Ghana and Equatorial Guinea may be subjected to substantially varying contractual fiscal terms that affect the net revenue to Kosmos for the production of these volumes. The prices and economic return received for these net volumes can vary materially based on the terms of these contracts. Therefore, when applicable, Ryder Scott reviewed the fiscal terms of such contracts and discussed with Kosmos the net economic benefit attributed to such operations for the determination of the net hydrocarbon volumes and income thereof. Ryder Scott has not conducted an exhaustive audit or verification of such contractual information. Neither our review of such contractual information nor our acceptance of Kosmos representations regarding such contractual information should be construed as a legal opinion on this matter.

Ryder Scott did not evaluate the country and geopolitical risks in the countries where Kosmos operates or has interests. Kosmos operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which Kosmos owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission’s Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the “quantities actually recovered are much more likely to be achieved than not.” The SEC states that “probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.” The SEC states that “possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves.” All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods, the volumetric method, analogy, or a combination of methods. Approximately 9.2 percent of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods. The performance methods include, but may not be limited to, decline curve analysis, material balance and/or reservoir simulation which utilized extrapolations of historical production and pressure data available through December, 2019 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Kosmos and were considered sufficient for the purpose thereof. The remaining 90.8 percent of the proved producing reserves were estimated by the volumetric method, analogy, or a combination of methods. These methods were used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserves estimates was considered to be inappropriate. However, available performance data were used to ensure the volumetric parameters in our estimates derived from the volumetric method were appropriate.

Approximately 3.5 percent of the proved developed non-producing reserves included herein were estimated by the performance method. The remaining 96.5 percent of the proved developed non-producing reserves and all of the proved undeveloped reserves for the properties included herein were estimated by a combination of the volumetric method, analogy and performance method. The volumetric analysis utilized pertinent well and seismic data furnished to Ryder Scott by Kosmos or obtained from public data sources that were available through December 15, 2019. The data utilized from the analogues as well as well and seismic data incorporated into our volumetric analysis were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Kosmos has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by Kosmos with respect to property interests owned, contractual terms that govern future net income, production and well tests from examined wells, normal direct costs of operating the wells or leases and all the required facilities such as the FPSO, other costs such as transportation and/or processing fees, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Kosmos. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If a decline trend has been established, this trend was used as the basis for estimating future production rates. If no production decline trend has been established, one of the following occurred:

- future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves.

- future production rates were projected based on a type well derived from analogy to surrounding historical well production.

- future production rates were based on a combination of historical performance data, volumetric analysis and a robust numerical simulation model. Future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated “simulation based decline rate” was then applied until depletion of the reserves.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Kosmos. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract.

Kosmos furnished us with the above mentioned average prices in effect on December 31, 2019. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, NGL processing fees, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by Kosmos. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Kosmos to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Price	Average Realized Price
West Africa				
Greater Jubilee and TEN Project Areas	Oil	Brent	$62.69/BBL	$63.72/BBL
	Gas	Contract	$0.60/MCF	$0.60/MCF
Central Africa				
Ceiba and Okume Project Areas	Oil	Brent	$62.69/BBL	$63.12/BBL
North America				
Gulf of Mexico Project Area	Oil/ Condensate	Heavy Louisiana Sweet	$61.31/BBL	$58.26/BBL
	NGLs	Heavy Louisiana Sweet	$61.31/BBL	$14.76/BBL
	Gas	Henry Hub	$2.58/MMBTU	$1.77/MCF

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the contract areas and wells in this report were furnished by Kosmos and are based on their operating expense reports and include only those costs directly applicable to the contract areas or wells. The operating costs include a portion of general and administrative costs allocated directly to the contract areas and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. Certain gas, oil and condensate processing and handling fees, including compression fees where applicable are included as “other” and “Ad Valorem Taxes” deductions in the cash flows. The later are not true ad valorem taxes but represent Kosmos’ throughput fee to Talos for processing and handling of the production volumes from the Tornado field. The separate tracking of this throughput fee in the “Ad Valorem Taxes” column of the cash flows was done at Kosmos’ request. For some Gulf of Mexico Project Area assets, we calculated their operating costs using Lease Operating Statements (LOE) provided by Kosmos. For the remaining assets, the operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by Kosmos. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the contract areas or wells.

Development costs were furnished to us by Kosmos and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by Kosmos were accepted without independent verification. Kosmos advises that their contractual share of Mississippi Canyon 697/698/741/742 (Big Bend) field, in the Gulf of Mexico Project Area, Plug and Abandonment (P&A) liability is zero.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with Kosmos' plans to develop these reserves as of December 31, 2019. The implementation of Kosmos' development plans as presented to us and incorporated herein is subject to the approval process adopted by Kosmos' management. As the result of our inquiries during the course of preparing this report, Kosmos has informed us that the development activities included herein have been subjected to and received the internal approvals required by Kosmos management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Kosmos. Kosmos has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, Kosmos has informed us that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans. While these plans could change or evolve from those under existing economic conditions as of December 31, 2019, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by Kosmos were held constant throughout the life of the properties. However, in some contract areas, anticipated changes to operations during the field life-ramp-down, specifically consolidation of activates, reduced well count and/or fluid handling, and other synergies, are projected to result in certain cost reductions.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to Kosmos Energy Limited. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Kosmos.

Kosmos makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Kosmos has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Forms S-3 and S-8 of Kosmos Energy Limited of the references to our name as well as to the references to our third party report for Kosmos Energy Limited, which appears in the December 31, 2019 annual report on Form 10-K of Kosmos Energy Limited. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Kosmos Energy Limited.

We have provided Kosmos with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Kosmos and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

\s\ Tosin Famurewa

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\s\ Christine E. Neylon

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\s\ Victor Abu

Victor Abu, P.E
TBPE License No. 132717
Vice President **[SEAL]**

TF-CEN-VA (GR)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. (Ryder Scott). Tosin Famurewa was the primary technical person responsible for overseeing the estimate of the reserves, future production and income prepared by Ryder Scott presented herein.

Mr. Famurewa, an employee of Ryder Scott since 2006, is a Managing Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Famurewa served in a number of engineering positions with Chevron and Texaco. For more information regarding Mr. Famurewa's geographic and job specific experience, please refer to Ryder Scott's website at www.ryderscott.com/Experience/Employees.

Mr. Famurewa earned double Bachelor of Science degrees in Chemical Engineering and Material Science and Engineering from University of California at Berkeley in 2000 and a Master of Science degree in Petroleum Engineering from University of Southern California in 2007. He is a licensed Professional Engineer (P.E.) in the State of Texas and a SPE Certified Petroleum Engineer (S.P.E.C.). He is also a member of the Society of Petroleum Engineers (SPE) and the Society of Petroleum Evaluation Engineers (SPEE).

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Famurewa fulfills. As part of his 2019 continuing education hours, Mr. Famurewa attended and internally received over 15 hours of formalized training, some of which related to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register. Mr. Famurewa is a regular speaker on reserve related topics at the annual Sub-Saharan Africa Oil and Gas Conference in Houston, TX.

Based on his educational background, professional training and more than 19 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Famurewa has attained the professional qualifications as a Reserves Estimator and Reserves Auditor as set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

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

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

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

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

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

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

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

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

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

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

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

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

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

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

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Exhibit 99.2

KOSMOS ENERGY LIMITED

Estimated

Future Reserves and Income

Derived Through Certain Production Sharing Contracts

Greater Tortue Project Area

Offshore, Mauritania and Senegal

Proved Reserves

SEC Parameters

As of

January 31, 2020

\s\ Tosin Famurewa	\s\ Amara Okafor
Tosin Famurewa, P.E., S.P.E.C.	Amara Okafor, P.E.
TBPE License No. 100569	TBPE License No. 113166
Managing Senior Vice President	Vice President

[SEAL] **[SEAL]**

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

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TELEPHONE (713) 651-9191

February 12, 2020

Kosmos Energy Limited
8176 Park Lane, Suite 500
Dallas, Texas 75231

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income derived through certain production sharing contracts of Kosmos Energy Limited (Kosmos) as of January 31, 2020. The subject properties are located in the countries of Mauritania and Senegal, offshore Northwest Africa, in the C-8 and St. Louis Offshore Profond blocks, hereafter referred to as the “Greater Tortue Project Area” (GTA). The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on February 12, 2020 and presented herein, was prepared for public disclosure by Kosmos in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott in this report represent a portion of Kosmos as of January 31, 2020. Kosmos has represented that it has interests with proved reserves in other assets. These other assets are located in Ghana, offshore West Africa, in the West Cape Three Points (WCTP) and Deep Water Tano (DWT) blocks, also referred to as the “Greater Jubilee and TEN Project Areas,” Equatorial Guinea, offshore Central Africa, in the G and F blocks, also referred to as the “Ceiba and Okume Project Areas” and United States of America, federal waters offshore Louisiana and Texas, also referred to as the “Gulf of Mexico Project Area.” Ryder Scott has evaluated these other assets and such results, with an as-of-date of December 31, 2019, were included in a separate report, dated January 22, 2020, provided to Kosmos.

The estimated reserves and future net income amounts presented in this report, as of January 31, 2020, are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. At Kosmos’ request, we have included estimated gross (100%) reserves, along with the estimated net reserves and income data. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Gross (100%) Reserves[1]
Derived Through Certain Interests of
Kosmos Energy Limited – GTA

As of January 31, 2020

	Total Proved Undeveloped
Gross (100%) Reserves	
Oil/Condensate – Mbbl	31,975
Plant Products – MBOE	352,364
Produced Gas – MMcf[2]	2,289,503
Fuel Gas – MMcf	175,319

[1]These volumes are 100% gross and have not been netted down to Kosmos' interest.

[2]Produced gas is gas produced at the wellhead, before the extraction of plant products (which consists of Liquified Natural Gas (LNG)) and consumed fuel gas and gas flared as part of operations. Does not include domestic gas.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Derived Through Certain Interests of
Kosmos Energy Limited – GTA

As of January 31, 2020

		Total Proved Undeveloped
Net Reserves		
Oil/Condensate – Mbbl		7,648
Plant Products – MBOE		84,284
Sales Gas – MMcf		0
Fuel Gas – MMcf		46,829
Income Data ($M)		
Future Gross Revenue		$3,798,055
Deductions		3,071,611
Future Net Income (FNI)	$	726,444
Discounted FNI @ 10%	$	79,650

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). Fuel gas volumes are attributed to those volumes of gas that are consumed for fuel in field operations while sales gas volumes are reported on an "as sold basis." All gas volumes are expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. The plant products are Liquified Natural Gas (LNG). The plant products (LNG) are shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent. MBOE means thousand barrels of oil equivalent. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using economic models developed in Microsoft EXCEL. This program was used at the request of Kosmos. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The deductions incorporate the normal direct costs of operating the wells, development costs, and certain abandonment costs net of salvage. “Other deductions”, as shown in the cash flow projections, consist of BP’s carry balance credit to Kosmos, joint operating agreement (JOA) overhead cost and training cost. There are no production taxes associated with the project area. The future net income is before the deductions of state and federal or foreign income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist, nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for all of the total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded annually. Future net income was discounted at four other discount rates which were also compounded annually. These results are shown in summary form as follows.

	Discounted Future Net Income As of January 31, 2020
Discount Rate Percent	Total Proved
5	$302,518
15	$(43,735)
20	$(114,827)
25	$(156,911)

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission’s Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled “PETROLEUM RESERVES DEFINITIONS” is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled “PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES” in this report. There are no proved developed producing or non-producing reserves included in this report.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist.

Reserves are “estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.” All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves, and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Kosmos’ request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are “those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward.” The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a “high degree of confidence that the quantities will be recovered.”

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that “as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.” Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

The proved reserves reported herein are limited to the period prior to expiration of current contracts providing the legal rights to produce, or a revenue interest in such production unless evidence indicates that contract renewal is reasonably certain. Furthermore, the subject properties located offshore Mauritania and Senegal may be subjected to substantially varying contractual fiscal terms that affect the net revenue to Kosmos for the production of these volumes. The prices and economic return received for these net volumes can vary materially based on the terms of these contracts. Therefore, when applicable, Ryder Scott reviewed the fiscal terms of such contracts and discussed with Kosmos the net economic benefit attributed to such operations for the determination of the net hydrocarbon volumes and income thereof. Ryder Scott has not conducted an exhaustive audit or verification of such contractual information. Neither our review of such contractual information nor our acceptance of Kosmos representations regarding such contractual information should be construed as a legal opinion on this matter.

Ryder Scott did not evaluate the country and geopolitical risks in the countries where Kosmos operates or has interests. Kosmos operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and contract terms, the legal rights to produce hydrocarbons, including the granting, extension or termination of production sharing contracts, the fiscal terms of various production sharing contracts, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which Kosmos owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved undeveloped reserves for the properties included herein were estimated by the volumetric method and analogy. The volumetric analysis utilized pertinent well and seismic data furnished to Ryder Scott by Kosmos that were available through December 2019. The data utilized from the analogues as well as the seismic data incorporated into our volumetric analysis were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data, which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Kosmos has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by Kosmos with respect to property interests owned, contractual terms that govern future net income, production and well tests from examined wells, normal direct costs of operating the wells, other costs such as transportation and/or processing fees, development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Kosmos. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

There is currently no production from this project area. Dynamic simulation modelling and other related information were used to estimate the anticipated initial production rates for the locations. Sales were estimated to commence at an anticipated date furnished by Kosmos. Locations may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from the locations may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

Kosmos furnished us with the above mentioned average prices in effect on January 31, 2020. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by Kosmos and were accepted as factual data.

BP Gas Marketing Limited (BPGM) (the “buyer”) and BP Mauritania Investments Limited (BPMIL), BP Senegal Investments Limited (BPSIL), Kosmos Energy Mauritania (KEM), Kosmos Energy Investments Senegal Limited (KEISL), La Societe Mauritanienne Des Hydrocarbures et de Patrimione Miner (SMHPM), La Societe Des Petroles du Senegal (PETROSEN) (collectively known as the “seller group”), and the governments of the Islamic Republic of Mauritania and the Republic of Senegal executed a Sales Purchase Agreement (SPA) on February 11, 2020. This demonstrates the marketability of the gas and satisfies the reasonable expectation that there is a market for the gas. Based on the above, Ryder Scott has recognized these estimated recoverable volumes for GTA as proved reserves.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
West Africa				
Mauritania and Senegal	Condensate	Europe Brent F.O.B.	$64.58/Bbl	$64.58/Bbl
	LNG	(3)	$6.14/MMbtu	$39.20/BOE

[3]*The future LNG prices, as specified by Kosmos, are based on the SPA, which is set at 9.5 percent of Brent crude, with a specified heating value of 1.065 MMbtu/scf.*

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the contract areas and locations in this report were furnished by Kosmos and are based on their estimate of the operating expenses for this project and include only those costs directly applicable to the contract areas or locations. “Other deductions”, as shown in the cash flow projections, consist of BP’s carry balance credit to Kosmos, joint operating agreement (JOA) overhead cost and training cost. The operating costs include a portion of general and administrative costs allocated directly to the contract areas and locations. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by Kosmos. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the contract areas or wells.

Development costs were furnished to us by Kosmos and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by Kosmos were accepted without independent verification.

The proved undeveloped reserves in this report have been incorporated herein in accordance with Kosmos’ plans to develop these reserves as of January 31, 2020. The implementation of Kosmos’ development plans as presented to us and incorporated herein is subject to the approval process adopted by Kosmos’ management. As the result of our inquiries during the course of preparing this report, Kosmos has informed us that the development activities included herein have been subjected to and received the internal approvals required by Kosmos management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Kosmos. Kosmos has provided written documentation supporting their commitment to develop the proved volumes associated with the development plan used in this report. Additionally, Kosmos has informed us that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans. While these plans could change or evolve from those under existing economic conditions as of January 31, 2020, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

According to Item 1203 (d) of the SEC Regulations, an explanation should be included for the reasons “…why material amounts of proved undeveloped reserves … remain undeveloped for five years or more after disclosure as proved undeveloped reserves.” A material amount of proved undeveloped reserves in this report are forecast to be converted to developed beyond the five-year time frame. A five-year time frame for converting undeveloped to developed was adopted by the SEC, “unless specific circumstances justify a longer time frame.” The GTA project has an estimated cost of $16.289 Billion and is a partnership between BP Mauritania Investments Limited (BPMIL), BP Senegal Investments Limited (BPSIL), Kosmos Energy Mauritania (KEM), Kosmos Energy Investments Senegal Limited (KEISL), La Societe Mauritanienne Des Hydrocarbures et de Patrimione Miner (SMHPM), and La Societe Des Petroles du Senegal (PETROSEN), the last two being the National Oil Companies (NOC) of the governments of the Islamic Republic of Mauritania and the Republic of Senegal respectively. There are several long lead items including major equipment, pipelines, infrastructure for facilities that include a floating liquefied natural gas (FLNG) vessel, a deep-water floating production storage and offloading (FPSO) facility, and LNG gas processing facilities in a deep offshore environment. It is Ryder Scott’s opinion that these special circumstances allow for the recognition of proved reserves for locations that will be developed beyond the five-year time frame.

Current costs used by Kosmos were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to Kosmos Energy Limited. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Kosmos.

Kosmos makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Kosmos has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Forms S-3 and S-8 of Kosmos Energy Limited, of the references to our name, as well as to the references to our third party report as of January 31, 2020, dated February 12, 2020, for Kosmos Energy Limited, which appears in the 2019 annual report on Form 10-K of Kosmos Energy Limited. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Kosmos Energy Limited.

We have provided Kosmos with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Kosmos and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

\s\ Tosin Famurewa

Tosin Famurewa, P.E., S.P.E.C.
TBPE License No. 100569
Managing Senior Vice President **[SEAL]**

\s\ Amara Okafor

Amara Okafor, P.E.
TBPE License No. 113166
Vice President **[SEAL]**

TF-AO (FWZ)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. (Ryder Scott). Tosin Famurewa was the primary technical person responsible for overseeing the estimate of the reserves, future production and income prepared by Ryder Scott presented herein.

Mr. Famurewa, an employee of Ryder Scott since 2006, is a Managing Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Famurewa served in a number of engineering positions with Chevron and Texaco. For more information regarding Mr. Famurewa's geographic and job specific experience, please refer to Ryder Scott's website at www.ryderscott.com/Experience/Employees.

Mr. Famurewa earned double Bachelor of Science degrees in Chemical Engineering and Material Science and Engineering from University of California at Berkeley in 2000 and a Master of Science degree in Petroleum Engineering from University of Southern California in 2007. He is a licensed Professional Engineer (P.E.) in the State of Texas and a SPE Certified Petroleum Engineer (S.P.E.C.). He is also a member of the Society of Petroleum Engineers (SPE) and the Society of Petroleum Evaluation Engineers (SPEE).

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Famurewa fulfills. As part of his 2019 continuing education hours, Mr. Famurewa attended and internally received over 15 hours of formalized training, some of which related to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register. Mr. Famurewa is a regular speaker on reserve related topics at the annual Sub-Saharan Africa Oil and Gas Conference in Houston, TX.

Based on his educational background, professional training and more than 19 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Famurewa has attained the professional qualifications as a Reserves Estimator and Reserves Auditor as set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

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

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

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

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

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

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

> *(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and*
>
> *(B) The project has been approved for development by all necessary parties and entities, including governmental entities.*

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

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

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

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

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

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

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.