Kosmos Energy Ltd.
Form 10-K
February 22, 2016
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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, 2015

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)

Bermuda	98 0686001
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
Clarendon House	
2 Church Street	
Hamilton, Bermuda	HM 11
(Address of principal executive offices)	(Zip Code)

Registrant’s telephone number, including area code: +1 441 295 5950

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

Title of each class	Name of each exchange on which registered:
Common Shares $0.01 par value	New York 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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting 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

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 shares held by non affiliates, based on the per share closing price of the registrant's common shares as of the last business day of the registrant's most recently completed second fiscal quarter was $1,310,263,359.

The number of the registrant's Common Shares outstanding as of February 16, 2016 was 385,253,510.

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, 2015.

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. We have provided definitions for some of the industry terms used in this report in the "Glossary and Selected Abbreviations" beginning on page 2.

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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.
"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.
"Boepd"	Barrels of oil equivalent per day.
"Bopd"	Barrels of oil per day.
"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.
"Dry hole"	A well that has not encountered a hydrocarbon bearing reservoir expected to produce in commercial quantities.
"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.
"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 for taking on a portion of the drilling costs of one or more specific wells or other performance by the assignee as a condition of the assignment.

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"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 the drilling costs of one or more specific wells and/or other work as a condition of the assignment.
"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 the depletion of the Jubilee Field plus the net present value of the forecast of certain capital expenditures incurred in relation to the Jubilee Field and certain other fields in Ghana, to (y) the aggregate loan amounts outstanding under the Facility less the Resource Bridge, as applicable.
"FPSO"	Floating production, storage and offloading vessel.
"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.
"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 Jubilee Field and certain other fields in Ghana, to (y) the aggregate loan amounts outstanding under the Facility less the Resource Bridge, as applicable.
"Make whole redemption price"	The "make whole redemption price" is equal to the outstanding principal amount of such notes plus the greater of 1) 1% of the then outstanding principal amount of such notes and 2) the present value of the notes at 103.9% and required interest payments thereon through August 1, 2017 at such redemption date.
"MBbl"	Thousand barrels of oil.
"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.
"MMcf"	Million cubic feet of natural gas.
"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.
"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.

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"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.
"Reconnaissance contract"	A contract in which the owner of hydrocarbons gives an E&P company rights to perform evaluation of existing data or potentially acquire additional data but may not convey an exclusive option to explore for, develop, and/or produce hydrocarbons from the lease area.
"Resource Bridge"	Borrowing Base availability attributable to probable reserves and contingent resources from Jubilee Field Future Phases, Tweneboa, Enyenra and Ntomme fields and potentially Mahogany, Teak and Akasa fields.
"Shelf margin"	The path created by the change in direction of the shoreline in reaction to the filling of a sedimentary basin.
"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.
"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.
"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.
"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.
"Trap"	A configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not migrate.
"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.

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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 by the governments of Ghana, Mauritania, Morocco (including Western Sahara), Portugal, Sao Tome and Principe, Senegal or Suriname (or their respective national oil companies) or any other federal, state or local governments or authorities, to us;
- our dependence on our key management personnel and our ability to attract and retain qualified technical personnel;
- the ability to obtain and maintain financing and to comply with the terms under which such financing may be available;
- the volatility of oil and natural gas 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 greenhouse gas ("GHG") laws and regulations or the implementation, or interpretation, of those laws and regulations;

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- adverse effects of sovereign boundary disputes in the jurisdictions in which we operate, including an ongoing maritime boundary demarcation dispute between Cote d'Ivoire and Ghana impacting our operations in the Deepwater Tano Block offshore Ghana;
- environmental liabilities;
- geological, technical, drilling, production and processing problems;
- 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;
- our vulnerability to severe weather events;
- 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;
- the result of any legal proceedings or investigations we may be subject to;
- 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 a 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.

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PART I

Item 1. Business

General

Kosmos is a leading independent oil and gas exploration and production company focused on frontier and emerging areas along the Atlantic Margin. Our assets include existing production and development projects offshore Ghana, large discoveries offshore Mauritania and Senegal, as well as exploration licenses with significant hydrocarbon potential offshore Portugal, Sao Tome and Principe, Suriname, Morocco and Western Sahara. Kosmos is listed on the New York Stock Exchange ("NYSE") 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. Members of the management team—who had previously worked together making significant discoveries and developing them in Africa, the Gulf of Mexico, and other areas—established the company on a single geologic concept that previously had been overlooked by others in the industry, the Late Cretaceous play system.

Following our formation, we acquired multiple exploration licenses and proved the geologic concept with the discovery of the Jubilee Field within the Tano Basin in the deep waters offshore Ghana in 2007. This was the first of our discoveries offshore Ghana; it was one of the largest oil discoveries worldwide in 2007 and is considered one of the largest finds offshore West Africa during the last decade. As technical operator of the initial phase of the Jubilee Field, we planned and executed the development. Oil production from the Jubilee Field began in November 2010, just 42 months after initial discovery, a record for a deepwater development in this water depth in West Africa. Gross production from the Jubilee Field averaged approximately 102,500 Bopd for 2015.

Following our Initial Public Offering, we acquired several new exploration licenses and again proved our geologic concept with the Ahmeyim discovery in the deepwater offshore Mauritania in 2015. The Ahmeyim discovery (formerly known as Tortue) was one of the largest natural gas discoveries worldwide in 2015 and is believed to be the largest ever gas discovery offshore West Africa. We have since demonstrated the extension of the gas discovery into Senegal with the successful Guembeul-1 exploration well.

Our business strategy focuses on achieving three key objectives: (1) maximize the value of our Ghana assets; (2) continue to explore and appraise the deepwater basin offshore Mauritania and Senegal to maximize and monetize value; and (3) increase value further through a high impact exploration program to unlock new petroleum systems. In Ghana, we are focused on increasing production, cash flows and reserves from the Jubilee Field, the development of the Tweneboa Enyenra Ntomme ("TEN") project, and the appraisal and development of our other Ghanaian discoveries. In Mauritania and Senegal, we expect to efficiently appraise and develop our current Ahmeyim discovery as well as continue to test our inventory of oil and gas prospects. We have a large inventory of leads and prospects in the remainder of our exploration portfolio which we plan to continue to build through new ventures and we plan to test this prospectivity targeting high impact opportunities along the Atlantic Margin.

Our Business Strategy

Grow proved reserves and production through exploration, appraisal and development

In the near term we plan to grow proved reserves and production by further developing and debottlenecking the Jubilee Field, including incorporating our Mahogany and Teak discoveries into the Greater Jubilee Full Field Development

Plan ("GJFFDP") and by completing the TEN development, which is expected to deliver first oil in the third quarter of 2016 through a second, dedicated FPSO. In the medium-term, growth could also be realized following the appraisal and ongoing assessment of commerciality and development over all or a portion of our new discoveries in Mauritania and Senegal. In the longer term, we plan to drill exploration prospects, with the intent to provide further growth in reserves and ultimately production.

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Successfully open and develop our offshore exploration plays

We believe the prospects and leads potentially existing offshore Mauritania, Portugal, Sao Tome and Principe, Senegal, Suriname and Western Sahara in particular provide a favorable opportunity to create substantial value through exploration drilling. Given the potential size of these prospects and leads, we believe that exploratory success in our operating areas could significantly add to our growth profile.

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

We differentiate ourselves from other exploration and production companies through our approach to exploration and development. Our geoscientists and engineers are critical to the success of our business strategy. We have created an environment that enables them to focus their knowledge, skills and experience on finding and developing new 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 strategies that maximize value. This philosophy and approach was successfully utilized offshore Ghana, Mauritania and Senegal, resulting in the discovery of significant new petroleum systems, which the industry previously did not consider either prospective or commercially viable.

Focus on optimally developing our discoveries to initial production

We focus on field developments designed to accelerate production, deliver early learnings and maximize returns. In certain circumstances, we believe a phased approach can be employed to optimize full field development through a better understanding of dynamic reservoir behavior and enable activities to be performed in a parallel rather than a sequential manner. A phased approach also 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 phase 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 phase of production to fund a portion of capital costs for subsequent phases. In contrast, a traditional development approach consists of full appraisal, conceptual engineering, preliminary engineering, detail engineering, procurement and fabrication of facilities, development drilling and installation of facilities for the full field development, all performed sequentially, before first production is achieved. This approach can considerably lengthen the time from discovery to first production.

For example, post discovery in 2007, first oil production from the Jubilee Field commenced in November 2010. This development timeline from discovery to first oil was significantly less than the seven to ten year industry average and set a record for a deepwater development of this size and scale at this water depth in West Africa. This condensed timeline reflects the lessons learned by our experienced team while leading other large scale deepwater developments.

Additionally, we look to partner with high quality, industry partners with world class development capabilities early in our exploration projects. This strategy is designed to ensure that upon successful exploration and appraisal activities, the project can benefit from development and production operations expertise provided by these partners, as we have done with BP plc (“BP”) in Morocco and Chevron Corporation (“Chevron”) in Suriname.

Identify, access and explore emerging regions and hydrocarbon plays

Our management and exploration teams have demonstrated an ability to identify regions and hydrocarbon plays that yield multiple large commercial discoveries. We focus on frontier and emerging areas that have been underexplored yet offer attractive commercial terms as a result of first mover advantage. We expect to continue to use our systematic and proven geologically focused approach in frontier and emerging petroleum systems where geological data suggests hydrocarbon accumulations are likely to exist, but where commercial discoveries have yet to be made. We believe this approach reduces the exploratory risk in poorly understood, under explored or otherwise overlooked hydrocarbon basins that offer significant hydrocarbon potential.

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This approach and focus, coupled with a first mover advantage and our management and technical teams' discipline in execution, provide a competitive advantage in identifying and accessing new strategic growth opportunities. We expect to continue seeking new opportunities where hydrocarbons have not been discovered or produced in meaningful quantities by leveraging the reputation and relationships of our experienced technical and management teams. This includes our existing areas of interest as well as selectively expanding our reach into other locations.

Farm in opportunities may offer a way to participate in new venture opportunities to undertake exploration in emerging basins, new plays and fairways to enhance and optimize our portfolio. Consistent with this strategy, we may also evaluate potential corporate and asset acquisition opportunities as a source of new ventures to support and expand our asset portfolio.

Maintain Financial Discipline

We strive to maintain a conservative financial profile and strong balance sheet with ample liquidity. Typically, we fund exploration activities from a combination of production cash flows or partner carries, and development activities from a combination of production cash flows and debt. As of December 31, 2015, we have approximately $1.8 billion of liquidity available to fund our opportunities. Additionally, we use derivative instruments to partially limit our exposure to fluctuations in oil prices and interest rates. We have an active commodity hedging program where we hedge a portion of our anticipated sales volumes on a two to three year rolling basis. As of December 31, 2015, we have hedged positions covering 10.9 million barrels of oil from 2016 to 2018, which provide partial downside protection should Dated Brent oil prices remain below our floor prices. We also maintain insurance to partially protect against loss of production revenues from our Jubilee asset.

Kosmos Exploration Approach

Kosmos' exploration philosophy is deeply rooted in a fundamental, geologically based approach geared toward the identification of misunderstood, under explored or overlooked petroleum systems. This process begins with detailed geologic studies that methodically assess a particular region's subsurface, with careful consideration given to those attributes that lead to working petroleum systems. The process includes basin modeling to predict oil or gas charge and fluid migration, as well as stratigraphic and structural analysis to identify reservoir/seal pair development and trap definition. This analysis integrates data from previously drilled wells where available and seismic data. Importantly, this approach also takes into account a detailed analysis of geologic timing to ensure that we have an appropriate understanding of whether the sequencing of geological events could promote and preserve hydrocarbon accumulation. Once an area is high graded based on this play/fairway analysis, geophysical analysis based on new 3D seismic is conducted to identify prospective traps of interest.

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 employed in both areas that have existing oil and natural gas production, as well as those regions that have yet to achieve commercial hydrocarbon production.

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 provide scale should the exploration concept prove successful. Kosmos also looks for long term contract duration to enable the "right" exploration program to be executed, play type diversity to provide multiple exploration concept options, prospect dependency to enhance the chance of replicating success and sufficiently attractive fiscal terms to maximize the commercial viability of discovered hydrocarbons.

Operations by Geographic Area

We currently have operations in Africa, Europe and South America. Currently, all operating revenues are generated from our operations offshore Ghana.

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Our Discoveries

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

Discoveries	License		Kosmos Participating Interest			Operator		Stage
Ghana								
Jubilee Field Phase 1 and Phase 1A(1)	WCTP/DT	(2)	24.1	%	(4)	Tullow		Production
Jubilee Field subsequent phases	WCTP/DT	(2)	24.1	%	(4)	Tullow		Development
TEN(1)	DT		17.0	%	(5)	Tullow		Development
Mahogany	WCTP		24.1	%	(6)	Kosmos	(6)	Appraisal
Teak	WCTP		24.1	%	(6)	Kosmos	(6)	Appraisal
Akasa	WCTP		30.9	%	(6,7)	Kosmos		Appraisal
Wawa	DT		18.0	%	(7)	Tullow		Appraisal
Mauritania								
Ahmeyim	Block C8	(3)	90.0	%	(8,9)	Kosmos	(8)	Appraisal
Marsouin	Block C8		90.0	%	(8,9)	Kosmos	(8)	Appraisal
Senegal								
Guembeul	Saint Louis Offshore Profond	(3)	60.0	%	(10)	Kosmos		Appraisal

(1) For information concerning our estimated proved reserves as of December 31, 2015, see "—Our Reserves."

(2) The Jubilee Field straddles the boundary between the West Cape Three Points ("WCTP") petroleum contract and the Deepwater Tano ("DT") petroleum contract offshore Ghana. Consistent with the Ghana Petroleum Exploration and Production Law of 1984 (PNDCL 84) (the "Ghanaian Petroleum Law"), the WCTP petroleum contract and DT petroleum contract and as required by Ghana's Ministry of Petroleum (formerly Ghana's Ministry of Energy and Petroleum), in order to optimize resource recovery in this field, we entered into the Unitization and Unit Operating Agreement (the "UUOA") in July 2009 with Ghana National Petroleum Corporation ("GNPC") and the other block partners of each of these two blocks. The 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.

(3) The Greater Tortue resource, 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. We have entered into a Memorandum of Understanding ("MOU") signed by Societe des Petroles du Senegal ("PETROSEN") and Societe Mauritanienne des Hydrocarbures et de Patrimoine Minier ("SMHPM"), the national oil companies of Senegal and Mauritania, respectively, which sets out the principles for an intergovernmental cooperation agreement for the development of the cross-border Greater Tortue resource.

(4) These interest percentages are subject to redetermination of the participating interests in the Jubilee Field pursuant to the terms of the UUOA. Our paying interest on development activities in the Jubilee Field is 26.9%.

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

(6) In September 2015, GNPC exercised its WCTP petroleum contract option, with respect to the Mahogany and Teak discoveries, to acquire an additional paying interest of 2.5%. We signed the Jubilee Field Unit Expansion Agreement with our partners in November 2015. This allows for the Mahogany and Teak discoveries to be

included in the GJFFDP. Upon approval of the GJFFDP by Ghana's Ministry of Petroleum, (a) the Jubilee Unit will be expanded to include the Mahogany and Teak discoveries, (b) revenues and expenses associated with these discoveries will be at the Jubilee Unit interests, and (c) operatorship of the Mahogany and Teak discoveries will be transferred to Tullow as Jubilee Unit operator. These interest percentages give effect to the exercise of GNPC's option and approval of the GJFFDP. Our paying interest on development activities in these discoveries is 26.9%. Our participating interest as of December 31, 2015 is 30.0%. Additionally, the WCTP Block partners have agreed they will take the steps necessary to transfer operatorship of the remaining portions of the WCTP Block to Tullow after approval of the GJFFDP by Ghana's Ministry of Petroleum.

(7) GNPC has the option to acquire additional paying interests in a commercial discovery on the WCTP Block and the DT Block of 2.5% and 5.0%, respectively. These interest percentages do not give effect to the exercise of such options.

(8) In March 2015, we closed a farm-out agreement covering our three license areas in Mauritania with Chevron. As a component of the consideration for the farm-out, Chevron was required to make an election by February 1, 2016, to either farm-in to the Tortue-1 exploration well by paying a disproportionate share of the costs incurred in drilling of the well or, alternatively elect to not farm-in to the Tortue-1 exploration well and pay a disproportionate share of the costs of a second contingent exploration or appraisal well in the contract areas, subject to maximum expenditure caps. Chevron failed to make this mandatory election by the required date. Consequently, pursuant to the terms of the farm-out agreement, Chevron has withdrawn from our Mauritania blocks. Subsequently, Chevron requested that we engage in discussions related to the possible reinstatement of Chevron’s interests in our Mauritania blocks and such discussions are ongoing. However, if no such agreement is reached in these discussions, Chevron’s 30% non-operated participating interest will be reassigned to us (subject to requisite government approvals), and our participating interests in the Block C8, C12 and C13 petroleum contracts will be 90%.

(9) SMHPM has the option to acquire up to an additional 4% paying interests in a commercial development.These interest percentages do not give effect to the exercise of such option.

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

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Exploration License Areas(1)

	Operator (Participating Interest)		Partners (Participating Interest)
Mauritania			
Block C8	Kosmos (90%)	(3)	SMHPM (10%)
Block C12	Kosmos (90%)	(3)	SMHPM (10%)
Block C13	Kosmos (90%)	(3)	SMHPM (10%)
Morocco (including Western Sahara)			
Cap Boujdour	Kosmos (55%)		Cairn (20%), ONHYM (25%)
Essaouira	Kosmos (30%)		BP (45%), ONHYM (25%)
Foum Assaka	Kosmos (29.9%)		BP (26.3%), ONHYM (25.0%), Pathfinder (9.4%), SK Innovation Co., Ltd (9.4%)
Tarhazoute	Kosmos (30%)		BP (45%), ONHYM (25%)
Portugal			
Ameijoa	Repsol (34%)		Kosmos (31%), Galp (30%), Partex (5%)
Camarao	Repsol (34%)		Kosmos (31%), Galp (30%), Partex (5%)
Mexilhao	Repsol (34%)		Kosmos (31%), Galp (30%), Partex (5%)
Ostra	Repsol (34%)		Kosmos (31%), Galp (30%), Partex (5%)
Sao Tome and Principe			
Block 5(2)	Kosmos (65%)		ANP (15%), Equator (20%)
Block 6	Galp (45%)		Kosmos (45%), ANP (10%)
Block 11	Kosmos (85%)		ANP (15%)
Senegal			
Cayar Offshore Profond	Kosmos (60%)		PETROSEN (10%), Timis (30%)
Saint Louis Offshore Profond	Kosmos (60%)		PETROSEN (10%), Timis (30%)
Suriname			
Block 42	Kosmos (50%)		Chevron (50%)
Block 45	Kosmos (50%)		Chevron (50%)

(1) In September 2015, we notified the government of Ireland and our partners that we are withdrawing from the Frontier Exploration Licenses 1/13, 2/13 and 3/13 offshore Ireland.
(2) In January 2016, we closed a farm-in agreement with Equator, an affiliate of Oando, for Block 5 offshore Sao Tome and Principe, whereby we acquired a 65% participating interest and operatorship in the block. Certain governmental approvals and processes are still required to be completed before this acquisition is effective.
(3) In March 2015, we closed a farm-out agreement covering our three license areas in Mauritania with Chevron. As a component of the consideration for the farm-out, Chevron was required to make an election by February 1, 2016, to either farm-in to the Tortue-1 exploration well by paying a disproportionate share of the costs incurred in drilling of the well or, alternatively elect to not farm-in to the Tortue-1 exploration well and pay a disproportionate share of the costs of a second contingent exploration or appraisal well in the contract areas, subject to maximum expenditure caps. Chevron failed to make this mandatory election by the required date. Consequently, pursuant to the terms of the farm-out agreement, Chevron has withdrawn from our Mauritania blocks. Subsequently, Chevron requested that we engage in discussions related to the possible reinstatement of Chevron's interests in our Mauritania blocks and such discussions are ongoing. However, if no such agreement is reached in these discussions, Chevron's 30% non-operated participating interest will be reassigned to us (subject to requisite government approvals), and our participating interests in the Block C8, C12 and C13 petroleum contracts will be 90%.

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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 Tano Basin represents the eastern extension of the Deep Ivorian Basin which resulted from the development of an extensional sedimentary basin caused by tensional forces associated with opening of the Atlantic Ocean, as South America separated from Africa in the Mid Cretaceous period. The Tano Basin forms part of the resulting transform margin which extends from Sierra Leone to Nigeria.

The Tano Basin sediments comprise a thick Upper Cretaceous, deepwater turbidite sequence which, in combination with a modest Tertiary section, provided sufficient thickness to mature an early to Mid Cretaceous source rock in the central part of the Tano Basin. This well defined reservoir and charge fairway forms the play which, when draped over the South Tano high (a structural high dipping into the basin), resulted in the formation of trapping geometries.

The primary reservoir types consist of well imaged Turonian and Campanian aged submarine fans situated along the steeply dipping shelf margin and trapped in an up dip direction by thinning of the reservoir and/or faults. Many of our discoveries have similar trap geometries.

The following is a brief discussion of our discoveries to date on our license areas offshore Ghana.

Jubilee Discovery

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 UUOA, the discovery area was unitized for purposes of joint development by the WCTP and DT Block partners. Our current unit interest is 24.1%.

The Jubilee Field is a combination structural stratigraphic trap with reservoir intervals consisting of a series of stacked Upper Cretaceous Turonian aged, deepwater turbidite fan lobe and channel deposits.

The Jubilee Field is located approximately 37 miles offshore Ghana in water depths of approximately 3,250 to 5,800 feet, 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 Phase 1 development focused on partial development of certain reservoirs in the Jubilee Field. The Kosmos led Integrated Project Team (“IPT”) successfully executed the initial 17 well development plan, which included nine producing wells that produced through subsea infrastructure to the “Kwame Nkrumah” FPSO, six water injection wells and two natural gas injection wells. This initial phase provided subsea infrastructure capacity for additional production and injection wells to be drilled in future phases of development.

The Phase 1A development provided further development to the currently producing Jubilee Field reservoirs. The Phase 1A development included the drilling of eight additional wells consisting of five production wells and three water injection wells. Approval was given for an additional well, a gas injector, considered as part of Phase 1A. The Phase 1A Addendum PoD was submitted to the Ministry of Petroleum in June 2015 and deemed approved in July 2015 to enable drilling and completion of two additional wells consisting of one production well and one water injection well.

In November 2015, we signed the Jubilee Field Unit Expansion Agreement with our partners to allow for the development of the Mahogany and Teak discoveries through the Jubilee FPSO and infrastructure. The expansion of the Jubilee Unit becomes effective upon approval of the GJFFDP by Ghana's Ministry of Petroleum. The GJFFDP was submitted to the government of Ghana in December 2015. The GJFFDP includes further development of the three producing reservoirs and final development of the two remaining reservoirs to maximize ultimate recovery and asset value.

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The Government of Ghana completed the construction and connection of a gas pipeline from the Jubilee Field to transport natural gas to the mainland for processing and sale. In November 2014, the transportation of gas produced from the Jubilee Field commenced through the gas pipeline to the onshore gas plant. However, the uptime of the facility during 2016 and in future periods is not known. In the absence of the continuous export of large quantities of natural gas from the Jubilee Field it is anticipated that we will need to flare such natural gas. Currently, we have not been issued an amended permit from the Ghana Environmental Protection Agency ("Ghana EPA") to flare natural gas produced from the Jubilee Field in substantial quantities. Our inability to continuously export associated natural gas in large quantities from the Jubilee Field could impact our oil production.

In prior years, certain near wellbore productivity issues were identified, impacting several Phase 1 production wells. We have also experienced mechanical issues in the Jubilee Field, including failures of our water injection facilities on the FPSO and water and gas injection wells. This equipment downtime negatively impacted past oil production. The Jubilee Unit partners identified a means of successfully mitigating the near wellbore productivity issues with ongoing acid stimulation treatments and we are in the process of correcting the mechanical issues experienced in the Jubilee Field.

Oil production from the Jubilee Field averaged approximately 102,500 barrels (gross) of oil per day during 2015.

Following a February 2016 inspection of the turret area of the FPSO, by SOFEC, Inc. ("SOFEC"), the original turret manufacturer, a potential issue was identified with the turret bearing. As a precautionary measure, additional operating procedures to monitor the turret bearing and reduce the degree of rotation of the vessel are being put in place.

SOFEC will now undertake further offshore examinations and Tullow will work with SOFEC to determine what further measures will be required. Oil production and gas export is continuing as normal.

Deepwater Tano Block Discoveries

The Tweneboa, Enyenra and Ntomme fields are located in the western and central portions of the DT Block, approximately 30 miles offshore Ghana in water depths of approximately 3,300 to 5,700 feet. In November 2012, we submitted a declaration of commerciality and PoD over the TEN discoveries. In May 2013, the government of Ghana approved the TEN PoD. The discoveries are being jointly developed with shared infrastructure and a single FPSO.

The TEN fields consist of multiple stratigraphic traps with reservoir intervals consisting of a series of stacked Upper Cretaceous Turonian aged, deepwater fan lobes and channel deposits. Fluid samples recovered from the fields indicate an oil gravity of approximately 31 35 degrees API and a natural gas condensate gravity of between 41 and 48 degrees API.

The TEN development is being developed in a phased manner. The plan of development for TEN was designed to include an expandable subsea system that would provide for multiple phases. Phase 1 of the TEN development includes the drilling and completion of up to 17 wells, 11 of which have been drilled and are being completed. Seven additional development wells are expected to be drilled during Phase 2. The remaining Phase 1 and Phase 2 wells are a combination of production wells and water or gas injection wells needed to maximize recovery. The remainder of Phase 1 and all Phase 2 drilling is dependent on the International Tribunal for the Law of the Sea (the "ITLOS") ruling expected by late 2017.

The TEN development is on schedule and expected to deliver first oil in the third quarter of 2016 and is expected to increase towards the FPSO capacity of 80,000 barrels (gross) per day as the phased development progresses. Future development of gas resources at the TEN development is anticipated following the commencement of oil production.

The Wawa 1 exploration well intersected oil and gas condensate in a Turonian aged turbidite channel system. Pressure data shows that it is a separate accumulation from the TEN fields. Following additional appraisal and evaluation, a decision regarding the commerciality of the Wawa discovery will be made by the DT Block partners.

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Should the discovery be declared commercial, a PoD would be prepared for submission to Ghana's Ministry of Petroleum within six months of the declaration of commerciality.

West Cape Three Points Block Discoveries

Mahogany is located within the WCTP Block, southeast of the Jubilee Field. The field is approximately 37 miles offshore Ghana in water depths of approximately 4,100 to 5,900 feet. We believe the field is a combination stratigraphic structural trap with reservoir intervals contained in a series of stacked Upper Cretaceous Turonian aged, deepwater fan lobe and channel deposits.

The Teak discovery is located in the western portion of the WCTP Block, northeast of the Jubilee Field. The field is approximately 31 miles offshore Ghana in water depths of approximately 650 to 3,600 feet. We believe the field is a structural stratigraphic trap with an element of four way closure.

The Akasa discovery is located in the western portion of the WCTP Block approximately 31 miles offshore Ghana in water depths of approximately 3,200 to 5,050 feet. The discovery is southeast of the Jubilee Field. We believe the target reservoirs are channels and lobes that are stratigraphically trapped. The Akasa 1 well intersected oil bearing reservoirs in the Turonian zones. Fluid samples recovered from the well indicate an oil gravity of 38 degrees API.

The GJFFDP incorporating the Mahogany and Teak discoveries was submitted to the Ghanaian Ministry of Petroleum in December 2015. While we are currently in discussions with the government of Ghana, we can give no assurance that approval by the Ministry of Petroleum will be forthcoming in a timely manner or at all. We signed the Jubilee Field Unit Expansion Agreement with our partners in November 2015. This allows for the Mahogany and Teak discoveries to be developed contemporaneously with the Jubilee Field. Upon approval of the GJFFDP by the Ministry of Petroleum, the Jubilee Unit will be expanded to include the Mahogany and Teak discoveries and revenues and expenses associated with these discoveries will be at the Jubilee Unit interests. We are currently in discussions with the government of Ghana regarding additional technical studies and evaluation that we want to conduct before we are able to make a determination regarding commerciality of the Akasa discovery. Additionally, the WCTP Block partners have agreed they will take the steps necessary to transfer operatorship of the remaining portions of the WCTP Block to Tullow after approval of the GJFFDP by Ghana's Ministry of Petroleum.

Mauritania

We are operator of three Offshore Blocks, C8, C12 and C13, which are located on the western margin of the Mauritania Salt Basin. Our blocks both include and are adjacent to proven petroleum systems, with our primary targets being Cretaceous sediments in structural and stratigraphic traps. We believe that the Triassic salt basin formed at the onset of rifting and contains Jurassic, Cretaceous and Tertiary passive margin sequences of limestones, sandstone and shales. Interpretation of available geologic and geophysical data has identified Cretaceous basin floor channels and fans in trapping geometries outboard of the Salt Basin. Cretaceous source rocks penetrated by wells and typed to oils in the Mauritania Salt Basin are the same age as those which charge other oil and gas fields in the Late Cretaceous of West Africa.

Our acreage is located outboard of the Chinguetti Field and range in water depth from 4,900 to 9,800 feet. These blocks cover an aggregate area of approximately 6.6 million acres. We have obtained approximately 6,000 line-kilometers of 2D seismic data and 10,300 square kilometers of 3D seismic data covering portions of our blocks in Mauritania. Based on these 2D and 3D seismic programs, we have identified numerous prospects in our blocks and we continue to integrate the results of our successful drilling program in Mauritania to further evaluate our reservoir model and delineate prospectivity.

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The following is a brief discussion of our discoveries to date in Block C8 offshore Mauritania.

Block C8 Discoveries

The Ahmeyim discovery (formerly named Tortue) is located in Block C8 offshore Mauritania. The discovery is a significant, play-opening gas discovery for the outboard Cretaceous petroleum system. Based on analysis of drilling results and logging data, the well intersected approximately 117 meters (383 feet) of net hydrocarbon pay. A single gas pool was encountered in the Lower Cenomanian objective, which is comprised of three reservoirs totaling 88 meters (288 feet) in thickness over a gross hydrocarbon interval of 160 meters (528 feet). A fourth reservoir totaling 19 meters (62 feet) was penetrated within the Upper Cenomanian target over a gross hydrocarbon interval of 150 meters (492 feet). The exploration well also intersected an additional 10 meters (32 feet) of net hydrocarbon pay in the lower Albian section, which is interpreted to be gas. The well was drilled to a total depth of 5,107 meters. The Ahmeyim discovery extends across the Mauritania border into our Saint Louis Offshore Profond block offshore Senegal. In January 2016, we drilled the Guembeul-1 well in Senegal, which confirmed the extension of the Ahmeyim discovery into Senegal. We are currently drilling the Ahmeyim-2 well as part of the appraisal program in Mauritania to further delineate the Ahmeyim discovery.

The Marsouin discovery, 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 5,153 meters in nearly 2,400 meters of water. Based on analysis of drilling results and logging data, Marsouin-1 encountered at least 70 meters (230 feet) of net gas pay in Upper and Lower Cenomanian intervals comprised of excellent quality reservoir sands. An appraisal program is currently being planned to delineate the Marsouin discovery.

Senegal

We are the operator of the Cayar Offshore Profond and Saint Louis Offshore Profond Blocks offshore Senegal. The blocks are located in the Senegal River Mid Cretaceous deep water system, which is an extention of a working petroleum system in the Mauritania Salt Basin. We believe the area has multiple Lower Cretaceous source rocks with Albo Cenomanian reservoir sands. We obtained approximately 7,000 square kilometers of 3D seismic data over the central and eastern portions of the Cayar Offshore Profond and Saint Louis Offshore Profond blocks in January 2015. The results of these 3D seismic programs provided sufficient encouragement to begin acquiring additional seismic data in November 2015 in the western portions of both blocks to fully evaluate the prospectivity. This survey is expected to be completed in February 2016. We have identified numerous prospects in our blocks and we continue to integrate the results of our successful drilling program in Mauritania and Senegal to further evaluate our reservoir model and delineate prospectivity.

The following is a brief discussion of our discovery in the Saint Louis Offshore Profond Block offshore Senegal.

Saint Louis Offshore Profond Discoveries

The Guembeul-1 exploration well, located in the northern part of the Saint Louis Offshore Profond license area in Senegal, has made a significant gas discovery. The Guembeul-1 exploration well is located approximately five kilometers south of the Tortue-1 exploration well in Mauritania in approximately 2,700 meters of water and was drilled to a total depth of 5,245 meters. The well encountered 101 meters (331 feet) of net gas pay in two excellent quality reservoirs, including 56 meters (184 feet) in the Lower Cenomanian and 45 meters (148 feet) in the underlying Albian, with no water encountered. Importantly, the Guembeul-1 exploration well has demonstrated reservoir continuity as well as static pressure communication with the Tortue-1 exploration well in the Lower Cenomanian.

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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 and French Guyana. The Guyana-Suriname Basin resulted from rock deformation caused by tensional forces associated with the opening of the Atlantic Ocean, as South America separated from Africa in the Mid Cretaceous period. The Suriname basin is considered similar 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 nearby discoveries offshore Guyana.

Suriname Block 42 and Block 45 are positioned centrally in the Suriname-Guyana Basin, and located to the southeast of the recent play opening Liza-1 oil discovery. Likewise, the blocks are also positioned to the northwest of the French Guyana Basins' Zaedysus oil discovery.

We believe that there are several independent play types of importance to our operated blocks. Of note are the listric faulted structural stratigraphic play of the lower Cretaceous and the stratigraphically trapped Upper Cretaceous plays similar to those discovered offshore West Africa in the Ghanaian Jubilee Field. The recent oil discovery in Guyana (Liza-1) in the same geologic basin provides a positive point of calibration for the Upper Cretaceous stratigraphic play.

Target reservoirs in our blocks are similar Upper and Middle Cretaceous age basin floor fans and mid slope channel sands. Seismic evidence suggests thick Late Cretaceous and Tertiary reservoir systems are present in the deep water area demonstrated by Liza-1.

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 similar in age to those which charged some of the fields offshore West Africa.

During 2012, we completed a 3D seismic data acquisition program which covered approximately 3,900 square kilometers over portions of Block 42 and Block 45 offshore Suriname. In August 2013, we completed a 2D seismic program of approximately 1,400 line kilometers over a portion of Block 42, outside of the existing 3D seismic survey. The processing of the seismic data was completed during 2014.

In December 2015, we received an extension of Phase 1 of the Exploration Period for Block 42 offshore Suriname which now expires in September 2018. We have compiled an initial inventory of prospects on the license areas in Suriname and will continue to refine and assess the prospectivity of these areas during 2016.

Morocco (including Western Sahara)

Our petroleum contracts in Morocco include the Cap Boujdour Offshore Block, which is within the Aaiun Basin, and the Essaouira Offshore Block, the Foum Assaka Offshore Block and the Tarhazoute Offshore Block, which are within the Agadir Basin. We are the operator of these petroleum contracts.

Aaiun Basin

The Cap Boujdour Offshore Block is located within the Aaiun Basin, along the Atlantic passive margin and covers a high graded area within the original Boujdour Offshore Block which expired in February 2011. Detailed seismic sequence analysis suggests the possible existence of stacked deepwater turbidite systems throughout the region. The scale of the license area has allowed us to identify distinct exploration fairways in this block. The main play elements of the prospectivity within the Cap Boujdour Offshore Block consist of a Late Jurassic source rock, charging Early to Mid Cretaceous deepwater sandstones trapped in a number of different structural trends. In the inboard area a number of three way fault closures are present which contain Early to Mid Cretaceous sandstone sequences some of which have been penetrated in wells on the continental shelf. Outboard of these fault trap trends, large four way closure

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and combination structural stratigraphic traps are present in discrete northeast to southwest trending structurally defined fairways.

During 2014, we conducted a new 3D seismic survey of approximately 5,100 square kilometers over the Cap Boujdour Offshore Block. The processing of this seismic data was completed in 2015.

Drilling of the CB-1 exploration well on the Cap Boujdour Offshore Block was completed in March 2015. The well penetrated approximately 14 meters of net gas and condensate pay in clastic reservoirs over a gross hydrocarbon bearing interval of approximately 500 meters. The discovery was sub-commercial, and the well was plugged and abandoned. However, the well demonstrated a working petroleum system including the presence of a hydrocarbon charge. The results are being integrated with the ongoing geological evaluation to determine future exploration activity.

Agadir Basin

The Foum Assaka Offshore, Essaouira Offshore and Tarhazoute Offshore Blocks are located in the Agadir Basin. A working petroleum system has been established in the onshore area of the Agadir Basin based on onshore and shallow offshore wells. Existing well data and geological and geochemical studies have demonstrated the presence of Cretaceous source rocks in the acreage. Onshore production suggests that possible Jurassic source rocks are also present in the offshore Agadir Basin. The offshore Agadir Basin sediments are interpreted to comprise thick sequences of Lower to Upper Cretaceous age formations consisting of deep water channels and lobes. The interpreted prospects' trapping styles are varied and include pre salt ponded slope fans, salt domes, salt cored anticlines and sub salt structures.

We completed interpretation of approximately 7,800 square kilometers of new and reprocessed 3D seismic data in our Foum Assaka Offshore and Essaouira Offshore Blocks. During 2014, we conducted a 3D seismic data acquisition program of approximately 4,300 square kilometers over the Tarhazoute Offshore and Essaouira Offshore Blocks. The processing of this seismic data was completed in late 2015.

During 2014, we drilled the FA 1 exploration well in the Foum Assaka Offshore block. The well encountered oil and gas shows while drilling and in sidewall cores suggesting the presence of a working petroleum system; however, it failed to encounter commercial reservoirs and was plugged and abandoned.

We are currently assessing prospectivity on our Agadir Basin Blocks offshore Morocco and plan to continue processing and interpreting seismic information to assess the prospectivity of these license areas.

Portugal

In March 2015, we closed a farm in agreement to acquire a non operated interest in the Camarao, Ameijoa, Mexilhao and Ostra Blocks offshore Portugal. Offshore Atlantic Portugal has been identified as a potentially attractive Central Atlantic margin area with Jurassic source rocks and Lower Cretaceous reservoirs in combination traps. This overlooked and underexplored area has a number of wells showing good evidence for working charge from oil shows and drill stem tests in Late Jurassic and Early Cretaceous sandstones and limestones. These blocks cover an area of approximately 3.0 million acres in water depths ranging from approximately 200 to 3,200 meters.

During 2015, we conducted a 3D seismic survey of approximately 3,200 square kilometers over the Camarao Block. The processing of this seismic data is expected to be completed in 2016. We are integrating the results from the 3D seismic survey into our geologic model to further assess prospectivity on the blocks.

Sao Tome and Principe

During the fourth quarter of 2015 and in January 2016, Kosmos acquired acreage in Blocks 5, 6 and 11 offshore Sao Tome and Principe in the Gulf of Guinea. We are the operator of Block 11, Equator Exploration Limited ("Equator"), an affiliate of Oando Energy Resources, is the operator of Block 5 and Galp Energia Sao Tome E Principe, Unipessoal, LDA ("Galp"), a wholly owned subsidiary of Petrogal, S.A., is the operator of Block 6. These blocks cover an area of approximately 4.2 million acres in water depth ranging from 2,250 to 3,000 meters and provide an opportunity

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to pursue the core Cretaceous theme that was successful for us in Ghana. Block 5 is subject to certain governmental approvals and processes required to be completed before this acquisition is effective.

Our blocks are adjacent to a proven and prolific petroleum system in Equatorial Guinea and northern Gabon comprising Early Cretaceous post-rift source rocks and Late Cretaceous reservoirs and provide an extension of this basin.

We believe that the southern extent of the West African transform margin in Sao Tome and Principe comprises a series of Albian pull-apart basins formed during the separation of Africa from South America and provides the necessary conditions for the generation, migration and trapping of hydrocarbons. Early in the basin history, restricted marine conditions prevailed allowing rich source rocks to be deposited. Large sandstone depo-centers were developed at the structural junctions of rift and shear fault trends resulting in the deposition of deep-water slope channels and basin floor fans draping over and around anticlinal highs adjacent to fracture zones. These constitute the main play in the acreage.

We have approximately 1,250 line kilometers of 2D seismic covering portions of our blocks and have identified numerous leads in our Sao Tome and Principe acreage. We intend to further delineate this prospectivity with a seismic acquisition program which will facilitate a detailed geologic evaluation.

Our Reserves

The following table sets forth summary information about our estimated proved reserves as of December 31, 2015. See "Item 8. Financial Statements and Supplementary Data—Supplemental Oil and Gas Data (Unaudited)" for additional information.

All of our estimated proved reserves as of December 31, 2015 and 2014 were associated with our Jubilee Field and the TEN development in Ghana. Our estimated proved reserves as of December 31, 2013 were associated with our Jubilee Field in Ghana.

Summary of Oil and Gas Reserves

	2015 Net Proved Reserves(1)			2014 Net Proved Reserves(1)			2013 Net Proved Reserves(1)		
	Oil, Condensate, NGLs (MMBbl)	Natural Gas(2) (Bcf)	Total (MMBoe)	Oil, Condensate, NGLs (MMBbl)	Natural Gas(2) (Bcf)	Total (MMBoe)	Oil, Condensate, NGLs (MMBbl)	Natural Gas(2) (Bcf)	Total (MM
es ry									
bed	50	10	52	43	9	45	36	10	38
loped(3)	24	4	25	30	6	31	9	1	9
	74	14	76	73	14	75	45	11	47

(1) Our reserves associated with the Jubilee Field are based on the 54.4%/45.6% redetermination split, between the WCTP Block and DT Block. Totals within the table may not add as a result of rounding.
(2) These reserves represent only the estimated quantities of fuel gas required to operate the Jubilee and TEN FPSOs during normal field operations. No natural gas volumes, outside of the fuel gas reported, have been classified as

reserves. If and when a subsequent gas sales agreement is executed for Jubilee, a portion of the remaining gas may be recognized as reserves. If and when a gas sales agreement and the related infrastructure are in place for the TEN development, a portion of the remaining gas may be recognized as reserves.

(3) All of our proved undeveloped reserves are expected to be developed within five years or less from their initial disclosure as proved undeveloped reserves. As of December 31, 2015, we recognized 25 MMBoe of proved undeveloped reserves related to the TEN development, which is expected to begin first oil production in the third quarter of 2016.

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Changes for the year ended December 31, 2015, include an increase of 11.8 MMBbl of net proved reserves related to Jubilee field performance and in fill drilling results, which were partially offset by negative revisions to the TEN development of 2.1 MMBbl due to lower oil prices and by 8.6 MMBbl of net Jubilee production during 2015. During the year ended December 31, 2015, we incurred $80.6 million of capital expenditures related to the Jubilee Field Phase 1A and 1A addendum developments, which consisted of drilling and completing two wells, resulting in the conversion of approximately 3 MMBbl of net proved undeveloped reserves at December 31, 2014 to proved developed reserves as of December 31, 2015.

Changes for the year ended December 31, 2014, include an increase of 27 MMBbl of net proved reserves related to the initial recognition of reserves associated with the TEN development. Jubilee net proved oil reserves increased 11 MMBbl as a result of field performance and in fill drilling results, which was partially offset by 8.5 MMBbl of net Jubilee production during 2014. During the year ended December 31, 2014, we incurred $82.8 million of capital expenditures related to the Jubilee Field Phase 1A development, which resulted in the conversion of approximately 6 MMBbl of net proved undeveloped reserves at December 31, 2013 to proved developed reserves as of December 31, 2014. This conversion of proved undeveloped reserves to proved developed reserves was due to the drilling of the remaining Jubilee Field Phase 1A development wells.

Changes for the year ended December 31, 2013, include an increase of 11 MMBbl of proved reserves as a result of drilling and reservoir performance, which is partially offset by 8 MMBbl of net production during 2013. During 2013, approximately 1 MMBbl of proved undeveloped reserves at December 31, 2012 were converted to proved developed reserves as of December 31, 2013. During the year ended December 31, 2013, we incurred $116.6 million of capital expenditures related to the Jubilee Field Phase 1A development.

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, 2015. All estimated future net revenues are attributable to projected production from the Jubilee Field and the TEN development in Ghana. If we are unable to export associated natural gas in large quantities from the Jubilee Field and TEN development then production could be limited and the future net revenues discussed herein will be adversely affected.

	Estimated Future Net Revenues(4) (in millions except $/Bbl)
Estimated future net revenues	$ 1,546
Present value of estimated future net revenues:	
PV-10(1)	$ 1,169
Future income tax expense (levied at a corporate parent and intermediate subsidiary level)	—
Discount of future income tax expense (levied at a corporate parent and intermediate subsidiary level) at 10% per annum	—
Standardized Measure(2)	$ 1,169
Benchmark and differential oil price($/Bbl)(3)	$ 53.72

(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 (in our case, future Ghanaian tax expense), using prices based on an average of the first day of the months throughout 2015 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 (in our case, the effects of future Ghanaian tax expense). 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.

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(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 (in our case, future Ghanaian tax expense), 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. However, as we are a tax exempted company incorporated pursuant to the laws of Bermuda, we do not expect to be subject to future income tax expense related to our proved oil and gas reserves levied at a corporate parent level on future net revenues. Therefore, the year end 2015 estimate of PV 10 is equivalent to the Standardized Measure.

(3) The unweighted arithmetic average first day of the month prices for the prior 12 months was $54.13 for Dated Brent at December 31, 2015. The price was adjusted for crude handling, transportation fees, quality, and a regional price differential. These adjustments are estimated to include a $(0.41) discount relative to Dated Brent for the Jubilee Field. The adjusted price utilized to derive the Jubilee Field PV 10 is $53.72. It was determined that no differential should be applied for the TEN development since oil production has not yet begun for those fields, hence the price utilized to derive the TEN PV 10 is $54.13.

(4) Future net revenues and PV-10 have been adjusted from the reserve report which is based on the entitlements method as we account for oil and gas revenues under the sales method of accounting.

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, 2015 and 2014 has been prepared by Ryder Scott Company, L.P. ("RSC"), our independent reserve engineering firm, and for the year ended December 31, 2013 was prepared by Netherland, Sewell & Associates, Inc. ("NSAI"), our independent reserve engineering firm for such years, in accordance with the rules and regulations of the Securities and Exchange Commission ("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 using index prices for oil, without giving effect to derivative transactions, and were held constant throughout the life of the assets.

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, 2015 are based on costs in effect at December 31, 2015 and the 12 month unweighted arithmetic average of the first day of the month price for the year ended December 31, 2015, 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, 2015 and 2014, was established in 1937. Over the past 75 years, RSC has provided services to the worldwide petroleum industry that include the issuance

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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, 2015 and 2014, 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, 2015 and 2014 and related future net revenues and PV 10 at December 31, 2015 and 2014 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, 2015 reserve report was completed on January 21, 2016, and a copy is included as an exhibit to this report.

In connection with the preparation of the December 31, 2015 and 2014 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, 2015, based upon its evaluation. RSC's primary economic assumptions in estimates included an ability to sell Jubilee Field oil and TEN development oil at a price of $53.72 and $54.13, respectively, 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.

Netherland, Sewell & Associates, Inc. NSAI was established in 1961. Over the past 50 years, NSAI has provided services to the worldwide petroleum industry that include the issuance of reserves reports and audits, acquisition and divestiture evaluations, simulation studies, exploration resources assessments, equity determinations, and management and advisory services. NSAI professionals subscribe to a code of professional conduct and NSAI is a Registered Engineering Firm in the State of Texas.

For the year ended December 31, 2013, we engaged NSAI 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, 2013 and related future net revenues and PV 10 at December 31, 2013 are taken from reports prepared by NSAI, in accordance with petroleum engineering and evaluation principles which NSAI believes are commonly used in the industry and definitions and current regulations established by the SEC.

In connection with the preparation of the December 31, 2013 reserves report, NSAI prepared its own estimates of our proved reserves. In the process of the reserves evaluation, NSAI 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 NSAI which brought into question the validity or sufficiency of any such information or data, NSAI 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. NSAI 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. NSAI issued a report on our proved reserves at December 31, 2013, based upon its evaluation.

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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 and NSAI 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 production and development 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 Production and Development 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 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. Guadalupe Ramirez. Mr. Ramirez has been practicing consulting petroleum engineering at RSC since 1981. Mr. Ramirez is a Licensed Professional Engineer in the State of Texas (No. 48318) and has over 35 years of practical experience in petroleum engineering. He graduated from Texas A&M University in 1976 with a Bachelor of Science Degree in Mechanical Engineering. Mr. Ramirez 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 Production and Development 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 review reserve and resource estimates on an annual basis.

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Gross and Net Undeveloped and Developed Acreage

The following table sets forth certain information regarding the developed and undeveloped portions of our license areas as of December 31, 2015 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						
Jubilee Unit	27	7	—	—	27	7
West Cape Three Points(2)	—	—	101	31	101	31
Deepwater Tano(2)	—	—	138	24	138	24
Mauritania						
Block C8(3)	—	—	2,962	2,666	2,962	2,666
Block C12(3)	—	—	1,748	1,573	1,748	1,573
Block C13(3)	—	—	1,940	1,746	1,940	1,746
Morocco (including Western Sahara)						
Cap Boujdour	—	—	5,503	3,026	5,503	3,026
Essaouira	—	—	2,171	651	2,171	651
Foum Assaka	—	—	1,200	359	1,200	359
Tarhazoute	—	—	1,916	575	1,916	575
Portugal						
Ameijoa	—	—	733	227	733	227
Camarao	—	—	709	220	709	220
Mexilhao	—	—	791	245	791	245
Ostra	—	—	772	239	772	239
Sao Tome and Principe(4)						
Block 6	—	—	1,241	558	1,241	558
Block 11	—	—	2,209	1,878	2,209	1,878
Senegal						
Cayar Offshore Profond	—	—	1,350	810	1,350	810
Saint Louis Offshore Profond	—	—	1,650	990	1,650	990
Suriname						
Block 42	—	—	1,526	763	1,526	763
Block 45	—	—	1,267	633	1,267	633
Total	27	7	29,927	17,214	29,954	17,221

(1) Net acreage based on Kosmos' participating interest, before the exercise of any options or back in rights, except for our net acreage associated with the Jubilee Field, the TEN development and Mahogany and Teak discoveries in the WCTP Block, 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.

(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) In March 2015, we closed a farm-out agreement covering our three license areas in Mauritania with Chevron. As a component of the consideration for the farm-out, Chevron was required to make an election by February 1, 2016, to either farm-in to the Tortue-1 exploration well by paying a disproportionate share of the costs incurred in

drilling of the well or, alternatively elect to not farm-in to the Tortue-1 exploration well and pay a disproportionate share of the costs of a second contingent exploration or appraisal well in the contract areas, subject to maximum expenditure caps. Chevron failed to make this mandatory election by the required date. Consequently, pursuant to the terms of the farm-out agreement, Chevron has withdrawn from our Mauritania blocks. Subsequently, Chevron requested that we engage in discussions related to the possible reinstatement of Chevron's interests in our Mauritania blocks and

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such discussions are ongoing. However, if no such agreement is reached in these discussions, Chevron's 30% non-operated participating interest will be reassigned to us (subject to requisite government approvals), and our participating interests in the Block C8, C12 and C13 petroleum contracts will be 90%.

(4) In January 2016, we closed a farm-in agreement with Equator, an affiliate of Oando, for Block 5 offshore Sao Tome and Principe, whereby we acquired a 65% participating interest and operatorship in the block. Certain governmental approvals and processes are still required to be completed before this acquisition is effective. Once the farm-in agreement becomes effective, the gross and net undeveloped acres in Block 5 will be 703 thousand acres and 457 thousand acres, respectively.

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, 2015:

	Productive Oil Wells		Productive Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Ghana—Jubilee Unit	26	6.24	—	—	26	6.24
Ghana—Ten(1)	4	0.68	—	—	4	0.68

(1) Of the four productive oil wells, three (gross) or 0.51 (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, 2015														
Ghana Jubilee Unit	—	—	—	—	—	—	3	0.72	—	—	3	0.72	3	0.72
TEN	—	—	—	—	—	—	4	0.68	—	—	4	0.68	4	0.68
Morocco (including Western Sahara) Cap Boujdour	—	—	1	0.55	1	0.55	—	—	—	—	—	—	1	0.55
Total	—	—	1	0.55	1	0.55	7	1.40	—	—	7	1.40	8	1.95
Year Ended December 31, 2014														

Ghana														
Jubilee Unit	—	—	—	—	—	—	—	—	—	—	—	—	—	—
TEN	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Morocco (including Western Sahara)														
Foum Assaka	—	—	1	0.30	1	0.30	—	—	—	—	—	—	1	0.30
Total	—	—	1	0.30	1	0.30	—	—	—	—	—	—	1	0.30
Year Ended December 31, 2013														
Ghana														
Jubilee Unit	—	—	—	—	—	—	2	0.48	—	—	2	0.48	2	0.48
Deepwater Tano	—	—	1	0.18	1	0.18	—	—	—	—	—	—	1	0.18
Cameroon														
N'dian River	—	—	1	1.00	1	1.00	—	—	—	—	—	—	1	1.00
Total	—	—	2	1.18	2	1.18	2	0.48	—	—	2	0.48	4	1.66

(1) As of December 31, 2015, 12 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 13 development wells awaiting completion. These wells are shown as “Wells Suspended or Waiting on Completion” in the table below.

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(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.

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, 2015.

	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	—	—	—	—	—	—	2	0.48
West Cape Three Points	—	—	—	—	9	2.78	—	—
TEN	—	—	1	0.17	—	—	11	1.87
Deepwater Tano	—	—	—	—	1	0.18	—	—
Mauritania								
C8 (1)	—	—	—	—	3	2.70	—	—
Senegal								
Saint Louis Offshore Profond	1	0.60	—	—	—	—	—	—
Total	1	0.60	1	0.17	13	5.66	13	2.35

(1) In March 2015, we closed a farm-out agreement covering our three license areas in Mauritania with Chevron. As a component of the consideration for the farm-out, Chevron was required to make an election by February 1, 2016, to either farm-in to the Tortue-1 exploration well by paying a disproportionate share of the costs incurred in drilling of the well or, alternatively elect to not farm-in to the Tortue-1 exploration well and pay a disproportionate share of the costs of a second contingent exploration or appraisal well in the contract areas, subject to maximum expenditure caps. Chevron failed to make this mandatory election by the required date. Consequently, pursuant to the terms of the farm-out agreement, Chevron has withdrawn from our Mauritania blocks. Subsequently, Chevron requested that we engage in discussions related to the possible reinstatement of Chevron's interests in our Mauritania blocks and such discussions are ongoing. However, if no such agreement is reached in these discussions, Chevron's 30% non-operated participating interest will be reassigned to us (subject to requisite government approvals), and our participating interests in the Block C8, C12 and C13 petroleum contracts will be 90%.

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.

Significant License Agreements

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

West Cape Three Points Block

Effective July 22, 2004, Kosmos, the EO Group and GNPC entered into the WCTP petroleum contract covering the WCTP Block offshore Ghana in the Tano Basin. As a result of farm out agreements and other sales of partners' interests for the WCTP Block, Kosmos, Anadarko WCTP Company ("Anadarko"), Tullow Ghana Limited, a subsidiary

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of Tullow Oil plc ("Tullow") and PetroSA Ghana Limited ("PetroSA"), a wholly owned subsidiary of Petro S.A., participating interests are 30.9%, 30.9%, 26.4% and 1.8%, respectively. Kosmos is the operator; however, a letter agreement has been executed that obligates the WCTP partners to take the necessary steps to transfer operatorship of the WCTP Block to Tullow after approval of the GJFFDP by the Ministry of Petroleum. Upon approval of the GJFFDP, our participating interest in Mahogany and Teak will be at the Jubilee Unit interests. GNPC has a 10% participating interest and will be carried through the exploration and development phases. GNPC has the option to acquire additional paying interests in a commercial discovery on the WCTP Block of 2.5%. Under the WCTP petroleum contract, GNPC exercised its option to acquire an additional paying interest of 2.5% in the Jubilee Field development (see "—Jubilee Field Unitization"), the Mahogany discovery and the Teak discovery. GNPC is obligated to pay its 2.5% share of all future petroleum costs as well as certain historical development and production costs attributable to its 2.5% additional paying interests in the Jubilee Unit, Mahogany discovery and Teak discovery. Furthermore, it is obligated to pay 10% of the production costs of the Jubilee Field development allocated to the WCTP Block. In August 2009, GNPC notified us and our unit partners it would exercise its right for the contractor group to pay its 2.5% WCTP Block share of the Jubilee Field development costs and be reimbursed for such costs plus interest out of GNPC's production revenues under the terms of the WCTP petroleum contract. Kosmos is required to pay a fixed royalty of 5% and a sliding scale royalty ("additional oil entitlement") which escalates as the nominal project rate of return increases. 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 our three existing discoveries within the WCTP Block (Akasa, Mahogany and Teak) as the WCTP petroleum contract remains in effect after the end of the Exploration Period. Effective January 14, 2014, the Ministry of Petroleum and GNPC entered into a Memorandum of Understanding with Kosmos Energy, on behalf of the WCTP petroleum contract Block partners, wherein all parties have settled all matters pertaining to the Notices of Dispute for the Mahogany East PoD and the Cedrela Notice of Force Majeure, and the Ministry of Petroleum has approved the Appraisal Programs for the Mahogany, Teak, and Akasa discoveries. As a result of the settlement, a portion of the WCTP petroleum contract area which contained the Cedrela prospect has been relinquished. 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 Petroleum 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.

Deepwater Tano Block

Effective July 2006, Kosmos, Tullow and PetroSA entered into the DT petroleum contract with GNPC covering the DT Block offshore Ghana in the Tano Basin. The DT petroleum contract has a duration of 30 years from its effective date of July 19, 2006. As a result of farm out agreements and other sales of partners interests for the DT Block, Kosmos, Anadarko, Tullow and PetroSA's participating interests are 18%, 18%, 50% and 4%, respectively. Tullow is the operator. GNPC has a 10% participating interest and will be carried through the exploration and development phases. GNPC has the option to acquire additional paying interests in a commercial discovery on the DT Block of 5%. 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 TEN development. GNPC is obligated to pay its 5% of all future petroleum costs, including development and production costs attributable to its 5% additional paying interest. Furthermore, it is obligated to pay 10% of the production costs of the Jubilee Field development allocated to the DT Block. In August 2009, GNPC notified us and our unit partners that it would exercise its right for the contractor group to pay its 5% DT Block share of the Jubilee Field development costs and be reimbursed for such costs plus interest out of a portion of GNPC's production revenues under the terms of the DT petroleum contract. Kosmos is required to pay a fixed royalty of 5% and an additional oil entitlement which escalates as the nominal project rate of return increases. 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.

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In January 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 Law and the WCTP and DT petroleum contracts form the basis of our exploration, development and production operations on the WCTP and DT blocks. Pursuant to these petroleum contracts, most significant decisions, including PoDs and annual work programs, for operations other than exploration and appraisal, must be approved by a joint management committee, consisting of representatives of certain block partners and GNPC. Certain decisions require unanimity.

Jubilee Field Unitization

The Jubilee Field, discovered by the Mahogany 1 well in June 2007, covers an area within both the WCTP and DT Blocks. Consistent with the Ghanaian Petroleum Law, the WCTP and DT petroleum contracts and as required by Ghana's Ministry of Petroleum, it was agreed the Jubilee Field would be unitized for optimal resource recovery. A Pre Unit Agreement was agreed to between the contractors groups of the WCTP and DT Blocks in 2008, with a more comprehensive unit agreement, the UUOA, agreed to in 2009 which govern each party's respective rights and duties in the Jubilee Unit. Tullow is the Unit Operator, while Kosmos was the Technical Operator for the initial development of the Jubilee Field. The Jubilee Unit holders' interests are subject to redetermination in accordance with the terms of the UUOA. As a result of the initial redetermination process completed in October 2011, the tract participation was determined to be 54.4% for the WCTP Block and 45.6% for the DT Block. Our Unit Interest was increased from 23.5% to 24.1%. The accounting for the Jubilee Unit is in accordance with the redetermined tract participation stated. Although the Jubilee Field is unitized, Kosmos' participating interests in each block outside the boundary of the Jubilee Unit remain the same. Kosmos remains operator of the WCTP Block outside the Jubilee Unit area.

Morocco (including Western Sahara) Exploration Agreements

Effective September 1, 2011, we entered into the Cap Boujdour Offshore Petroleum Agreement as the operator. In October 2013, we entered into a farm out agreement with Cairn Energy PLC ("Cairn"), covering the Cap Boujdour Offshore block, offshore Western Sahara. In the first quarter of 2014, the Moroccan government issued a joint ministerial order approving the farm-out agreement. Under the terms of the farm out agreement, Cairn acquired a 20% non operated interest in the exploration permits comprising the Cap Boujdour Offshore block. Cairn paid 150% of its share of costs of a 3D seismic survey capped at $25.0 million. The 3D seismic survey was completed in September 2014. Cairn also contributed $12.3 million towards our future costs and paid $1.5 million for their share of costs incurred from the effective date of the contract through the closing date. Cairn funded Kosmos' share of the CB-1 exploration well capped at $100.0 million. After giving effect to the farm out, our participating interest in the Cap Boujdour Offshore block is 55% and we remain the operator. The Moroccan national oil company, Office National des Hydrocarbures et des Mines ("ONHYM"), has a carried 25% participating interest. We are required to pay a 10% royalty on oil produced in water depths of 200 meters or less (the first 300,000 tons produced are exempt from royalty) and a 7% royalty on oil produced in water depths deeper than 200 meters (the first 500,000 tons produced are exempt from royalty). These royalties are to be paid in kind or, at the election of the government of Morocco, in cash. A corporate tax rate of 30% is applied to profits at the license level following a 10 year tax holiday post first production, if any. The exploration term of the Cap Boujdour Offshore Permits is eight years and includes an initial exploration period of one year and six months, which was extended for one year to March 5, 2014, followed by the first extension period of two years and the second extension period of three years and six months. We entered the first extension period on March 5, 2014. By entering the first extension period we were obligated to drill one exploration well. To meet this obligation, we drilled the CB 1 exploration well which was completed in March 2015. The well failed to encounter commercial reservoirs and was plugged and abandoned. In the event of commercial success, we have the right to develop and produce oil and/or gas for

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a period of 25 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.

Effective July 1, 2011, we entered into the Foum Assaka Offshore Petroleum Agreement as operator. In August 2013, final government approvals and processes were completed for the acquisition of an additional 18.8% participating interest in the Foum Assaka block in the Agadir Basin offshore Morocco from Pathfinder, a wholly owned subsidiary of Fastnet, one of our block partners, and resulted in our participating interest being 56.2%. In October 2013, we entered into a farm out agreement with BP. In the first quarter of 2014, the Moroccan government issued joint ministerial orders approving the farm out agreement. Under the terms of the agreement, BP acquired a 26.3% non operating interest in the Foum Assaka Offshore block. BP funded Kosmos' share of the cost of the FA-1 exploration well in the block, subject to a maximum spend of $120.0 million, and paid its proportionate share of any well costs above the maximum spend. In the event a second exploration well is drilled, BP will pay 150% of its share of costs subject to a maximum spend of $120.0 million. After giving effect to the farm out, our participating interest is 29.9% in the Foum Assaka Offshore block and we remain the operator. The Moroccan national oil company, ONHYM, has a 25% participating interest and is carried by the block partners proportionately during the exploration phase. We are required to pay a 10% royalty on oil produced in water depths of 200 meters or less (the first 300,000 tons produced are exempt from royalty) and a 7% royalty on oil produced in water depths deeper than 200 meters (the first 500,000 tons produced are exempt from royalty). These royalties are to be paid in kind or, at the election of the government of Morocco, in cash. A corporate tax rate of 30% is applied to profits at the license level following a 10 year tax holiday post first production. The term of the Foum Assaka Offshore Permits, beginning on July 1, 2011, is eight years and includes an initial exploration period of two years and six months followed by the first extension period of two years and six months and the second extension period of three years. We entered the first extension period effective January 1, 2014. By entering the first extension period we were obligated to drill one exploration well. To meet this obligation, we drilled the FA 1 exploration well in 2014. The well failed to encounter commercial reservoirs and was plugged and abandoned. 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 for an additional period of 10 years under certain circumstances.

Effective April 2, 2012, we entered into the Essaouria Offshore Petroleum Agreement as operator. In January 2013, we closed on an agreement to acquire an additional 37.5% participating interest in the Essaouira Offshore block from Canamens Energy Morocco SARL, one of our block partners. Governmental approvals and processes for this acquisition were finalized in November 2013 and resulted in our participating interest in the Essaouira Offshore block being 75%. In October 2013, we entered into a farm out agreement with BP. In the first quarter of 2014, the Moroccan government issued joint ministerial orders approving the farm out agreement. Under the terms of the agreement, BP acquired a non operating interest in the Essaouria Offshore block. BP will fund Kosmos' share of the cost of one exploration well in the block, subject to a maximum spend of $120.0 million, and pay its proportionate share of any well costs above the maximum spend. In the event a second exploration well is drilled, BP will pay 150% of its share of costs subject to a maximum spend of $120.0 million. After giving effect to the farm out, our participating interest is 30% in the Essaouria Offshore block and we remain the operator. The Moroccan national oil company, ONHYM, has a 25% participating interest and is carried by the block partners proportionately during the exploration phase. We are required to pay a 10% royalty on oil produced in water depths of 200 meters or less (the first 300,000 tons produced are exempt from royalty) and 7% royalty on oil produced in water depths deeper than 200 meters (the first 500,000 tons produced are exempt from royalty). These royalties are to be paid in kind or, at the election of the government of Morocco, in cash. A corporate tax rate of 30% is applied to profits at the license level following a 10 year tax holiday post first production. The term of the Essaouria Offshore Permits, beginning November 8, 2011, is eight years and includes an initial exploration period of two years and six months followed by the first extension period of three years and the second extension period of two years and six months. We are currently in the first extension period of the exploration permit, which ends in May 2017. The work program for the first extension period includes a drilling obligation. The extension of the exploration phases are subject to fulfillment of specific work obligations. 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 for an additional period of 10 years under certain circumstances.

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Effective December 6, 2013, we entered into the Tarhazoute Offshore Petroleum Agreement as operator with a 75% participating interest. The Moroccan national oil company, ONHYM, has a 25% participating interest and is carried by the block partners proportionately during the exploration phase. In October 2013, we entered into a farm out agreement with BP. In the first quarter of 2014, the Moroccan government issued joint ministerial orders approving the farm out agreement. Under the terms of the agreement, BP acquired a 45% non operating interest in the Tarhazoute Offshore block. BP will fund Kosmos' share of the cost of one exploration well in the block, subject to a maximum spend of $120.0 million, and pay its proportionate share of any well costs above the maximum spend. In the event a second exploration well is drilled, BP will pay 150% of its share of costs subject to a maximum spend of $120.0 million. After giving effect to the farm out, our participating interest is 30% in the Tarhazoute Offshore block and we remain the operator. We are required to pay a 10% royalty on oil produced in water depths of 200 meters or less (the first 300,000 tons produced are exempt from royalty) and 7% royalty on oil produced in water depths deeper than 200 meters (the first 500,000 tons produced are exempt from royalty). These royalties are to be paid in kind or, at the election of the government of Morocco, in cash. A corporate tax rate of 30% is applied to profits at the license level following a 10 year tax holiday post first production. The exploration term of the Tarhazoute Offshore Permits, beginning December 9, 2013, is eight years and includes an initial exploration period of two years and six months followed by the first extension period of two years and six months and the second extension period of three years. 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 for an additional period of 10 years under certain circumstances.

Suriname Exploration Agreements

On December 13, 2011, we signed a petroleum contract covering Offshore Block 42 located offshore Suriname. We have a 50% participating interest in the block and are the operator. Staatsolie Maatschappij Suriname N.V. ("Staatsolie"), Suriname's national oil company, has the option to back into the contract with an interest of not more than 10% upon approval of a development plan. In November 2012, Kosmos closed an agreement with Chevron under which Kosmos assigned half of its interest in Block 42, offshore Suriname, to Chevron. Each party now has a 50% participating interest in Block 42 and Kosmos remains the operator. The Block 42 petroleum contract provides for us to recover our share of expenses incurred ("cost recovery oil") and our share of remaining oil ("profit oil"). Cost recovery oil is apportioned to Kosmos from up to 80% of gross production prior to profit oil being split between the government of Suriname and the contractor. Profit oil is then apportioned based upon "R factor" tranches, where the R factor is cumulative net revenues divided by cumulative net investment. A corporate tax rate of 36% is applied to profits. We are in the initial period of the exploration phase, which has been extended and ends in September 2018. There are two renewal periods consisting of three years for the first renewal period and two years for the second renewal period. Each renewal period carries a one well drilling obligation. In the event of commercial success, the duration of the contract will be 30 years from the effective date or 25 years from governmental approval of a plan of development, whichever is longer. Block 42 comprises approximately 1.5 million acres (approximately 6,176 square kilometers).

On December 13, 2011, we signed a petroleum contract covering Offshore Block 45 located offshore Suriname. We have a 50% participating interest in the block and are the operator. Staatsolie will be carried through the exploration and appraisal phases and has the option to back into the petroleum contract with an interest of not more than 15% upon approval of a development plan. In November 2012, Kosmos closed an agreement with Chevron under which Kosmos assigned half of its interest in Block 45, offshore Suriname, to Chevron. Each party now has a 50% participating interest in Block 45 and Kosmos remains the operator. The Block 45 petroleum contract provides for us to recover our share of expenses incurred ("cost recovery oil") and our share of remaining oil ("profit oil"). Cost recovery oil is apportioned to Kosmos from up to 80% of gross production prior to profit oil being split between the government of Suriname and the contractor. Profit oil is then apportioned based upon "R factor" tranches, where the R factor is cumulative net revenues divided by cumulative net investment. A corporate tax rate of 36% is applied to profits. We are currently in the initial period of the exploration phase, which has been extended and ends in September 2016. Following the initial period, there are two renewal periods consisting of two years each. Each renewal period carries a one well drilling obligation. In the event of commercial success, the duration of the contract will be 30 years from the effective date or 25 years from governmental approval of a plan of development, whichever is longer.

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Mauritania Exploration Agreements

Effective June 15, 2012, we entered into three petroleum contracts covering offshore Mauritania blocks C8, C12 and C13 with the Islamic Republic of Mauritania. We have a 90% participating interest and are the operator. The Mauritanian national oil company, SMHPM, currently has a 10% carried participating 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 acquire 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 Kosmos from up to 55% 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 include an initial exploration period of four years followed by the first extension period of three years and the second extension period of three years. Kosmos is currently in the first exploration period of the blocks, expiring in June 2016. The first extension period carries a seismic obligation and a one well drilling obligation and the second extension period carries an additional one well drilling obligation for each block. These obligations have been met for Block C8 and the seismic obligation has been met for Block C12 with work completed during the initial exploration period. 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 March 2015, we closed a farm out agreement with Chevron covering the C8, C12 and C13 petroleum contracts offshore Mauritania. Under the terms of the farm out agreement, Chevron acquired a 30% non operated working interest in each of the contract areas. As partial consideration for the farm-out, Chevron paid a disproportionate share of the costs of one exploration well, the Marsouin-1 exploration well, as well as its proportionate share of certain previously incurred exploration costs. As a further component of the consideration for the farm-out, Chevron was required to make an election by February 1, 2016, to either farm-in to the Tortue-1 exploration well by paying a disproportionate share of the costs incurred in drilling of the well or, alternatively elect to not farm-in to the Tortue-1 exploration well and pay a disproportionate share of the costs of a second contingent exploration or appraisal well in the contract areas, subject to maximum expenditure caps. Chevron failed to make this mandatory election by the required date. Consequently, pursuant to the terms of the farm-out agreement, Chevron has withdrawn from our Mauritania blocks. Subsequently, Chevron requested we engage in discussions related to the possible reinstatement of Chevron's interests in our Mauritania blocks and such discussions are ongoing. However, if no such agreement is reached in these discussions, Chevron's 30% non-operated participating interest will be reassigned to us (subject to requisite government approvals), and our participating interests in the Block C8, C12 and C13 petroleum contracts will be 90%.

Portugal Explorations Agreements

In August 2014, we entered into a farm in agreement with Repsol to acquire a non operated interest in the Camarao, Ameijoa, Mexilhao and Ostra blocks in the Peniche Basin offshore Portugal. In March 2015, the Portuguese government issued the requisite approvals for the assignment to us. As part of the agreement, we reimbursed a portion of Repsol's previously incurred exploration costs, as well as partially carried Repsol's share of the costs of a 3D seismic program. After giving effect to the farm-in agreement, our participating interest is 31% in each of the blocks. Repsol is the operator.

The petroleum contracts for the four blocks were awarded in May of 2007 and each provides for an initial exploration phase of eight years and possible extensions. The initial exploration period has been extended through various amendments. The exploration period now ends in 2022, with drilling obligations in years eleven (June 2017 to June 2018), thirteen (June 2019 to June 2020) and fifteen (June 2021 to June 2022). At the end of each contract year, we may elect to fully relinquish the blocks without further obligation. Drilling a well on any block serves to fulfill the requirement for all four blocks. We are obligated to relinquish at least 50% of the total contract areas at the end of contract year twelve (with at least 25% from each contract area) and at least 50% of the total contract areas at the end of the second year of extension of the initial term.

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In September 2015, we completed a 3D seismic survey of approximately 3,200 square kilometers over the Camarao block offshore Portugal.

Senegal Exploration Agreements

In August 2014, we entered into a farm in agreement with Timis Corporation Limited ("Timis"), whereby we acquired a 60% participating interest and operatorship, covering the Cayar Offshore Profond and Saint Louis Offshore Profond Contract Areas offshore Senegal. In September 2014, the Senegal government issued the requisite approvals for the assignment to us. As part of the agreement, we carried the full costs of a 3D seismic program which was completed in January 2015. Additionally, we carried the full costs of the Guembeul-1 exploration well and will fund the Timis' share of the costs of a second contingent exploration well in either contract area, subject to a maximum gross cost per well of $120.0 million, should Kosmos elect to drill such well. We also retain the option to increase our equity interest in each contract area to 65% in exchange for carrying the full cost of a third exploration or appraisal well in either contract area, subject to a maximum gross cost of $120.0 million.

In June 2015, we entered the first renewal of the exploration period for the Cayar Offshore Profond and Saint Louis Offshore Profond Contract Areas, which lasts for three years. The exploration phase of each contract area may be extended to December 2020 at our election subject to our fulfilling specific work obligations including an exploration well in the current exploration period and an exploration well in the final period of two and one half years. 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 for at least one additional period of 10 years under certain circumstances.

Sao Tome and Principe Exploration Agreements

In October 2015, we closed a sale and purchase agreement with ERHC Energy EEZ, LDA, whereby we acquired an 85% participating interest and operatorship in Block 11 offshore Sao Tome and Principe. The Agencia Nacional do Petroleo ("ANP") has a carried 15% participating interest. The production sharing contract was awarded in July 23, 2014, and provides for an initial exploration period of eight years with possible extensions and includes a first phase exploration period of four years followed by the second phase of two years and the third phase of two years. The work program for the first phase includes a 2D seismic acquisition obligation and the next the exploration phases are subject to fulfillment of specific work obligations. In the event of commercial success, we have the right to develop and produce oil and/or gas for a period of 20 years from the approval of a field development program from ANP, which may be extended for additional periods of five years until all hydrocarbons have been economically depleted.

In November 2015, we closed a farm-in agreement with Galp to acquire a non-operated 45% participating interest in Block 6 offshore Sao Tome and Principe. The ANP has a carried 10% participating interest. The production sharing contract was awarded in October 2015, and provides for an initial exploration period of eight years with possible extensions and includes a first phase exploration period of four years followed by the second phase of two years and the third phase of two years. The work program for the first phase includes a 2D or 3D seismic acquisition obligation and the next exploration phases are subject to fulfillment of specific work obligations. In the event of commercial success, we have the right to develop and produce oil and/or gas for a period of 20 years from the approval of a field development program from ANP, which may be extended for additional periods of five years until all hydrocarbons have been economically depleted.

In January 2016, we closed a farm-in agreement with Equator, an affiliate of Oando, for Block 5 offshore Sao Tome and Principe, whereby we acquired a 65% participating interest and operatorship in each block. Certain governmental approvals and processes are still required to be completed before these acquisitions are effective.

Sales and Marketing

As provided under the UUOA and the WCTP and DT petroleum contracts, we are entitled to lift and sell our share of the Jubilee production in conjunction with the Jubilee Unit partners. We have entered into an agreement with an oil marketing agent to market our share of the Jubilee 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.

There are a variety of factors which affect the market for oil, including the proximity and capacity of transportation facilities, demand for oil, 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 and developing licenses. 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 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 experienced an extended decline in crude oil prices. Dated Brent crude, the benchmark for our oil sales, ranged from approximately $35-67 per barrel during 2015. Excluding the impact of hedges, our realized price for 2015 was $52.32 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 competition perspective are not entirely known at this point.

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 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;
- 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 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 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.

For example, the Macondo spill in the Gulf of Mexico in 2010 has resulted and will likely continue to result in increased scrutiny, regulation, costs and liabilities in the United States. The governments of the countries in which we currently, or in the future may, operate may also impose increased regulation as a result of this or similar incidents, which could materially delay, restrict or prevent our operations in those countries.

Capping and Containment

We entered into an agreement with a third party service provider to supply subsea capping and containment equipment on a global basis. 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.

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. The new dispersant stockpile, which is managed by Oil Spill Response Limited (“OSRL”) of Southampton, United Kingdom (“UK”), 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 approximate to the amount used in the Macondo spill response.

Ghana

Kosmos maintains an Oil Spill Contingency Plan (“OSCP”) for the coordination of responses to oil spills that might arise from our operations in Ghana. No exploration drilling is expected in the WCTP Block in 2016. Tullow, our partner and the operator of the Jubilee Unit and TEN development, however maintains an OSCP covering the Jubilee Field and DT Block. Both plans are based on the principle of “Tiered Response” to oil spills (“Guide to Tiered Response and Preparedness”, IPIECA Report Series, Volume 14, 2007). A Tier 1 spill is defined as a small scale operational incident which can be addressed with resources that are immediately available to us. A Tier 2 spill is a larger incident

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which would need to be addressed with regionally based shared resources. A Tier 3 spill is a large incident which would require assistance from national or world wide spill co operatives. Under the OSCPs, emergency response teams may be activated to respond to oil spill incidents. We maintain a tiered response system for the mobilization of resources depending on the severity of an incident. While a Tier 3 incident is not expected in Ghana, in the case of a Tier 3 incident, we would engage the services of OSRL.

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. Tier 1 equipment, which is stored in "ready to go trailers" for effective mobilization and deployment, includes booms and ancillaries, recovery systems, pumps and delivery systems, oil storage containers, personal protection equipment, sorbent materials, hand tools, containers and first aid equipment. Tier 2 equipment consists of larger boom and oil recovery systems, pump and delivery systems and auxiliary equipment such as generators and lighting sets, and is also containerized and pre packed in trailers and ready for mobilization.

Tullow has additional response capability to handle an offshore Tier 1 response. Further, our membership in the West and Central Africa Aerial Surveillance and Dispersant Spraying Service ("WACAF") gives us access to aircraft for surveillance and spraying of dispersant, which is administered by OSRL for a Tier 2 offshore response. The aircraft is based at the Kotoka International Airport in Accra, Ghana with a contractual response time, loaded with dispersant, of six hours. Additional stockpiles of dispersant are maintained in Takoradi. Although the above arrangement is in place, we can make no assurance that these resources will be available or respond in a timely manner as intended, perform as designed or be able to fully contain or cap any oil spill, blow out or uncontrolled flow of hydrocarbons.

Morocco (including Western Sahara), Mauritania and Senegal

We have a specific Oil Spill Contingency Plan to support our drilling operations in countries where we operate. The plan calls for the addition of Tier 1 spill equipment to our shorebase in Agadir, Morocco, Nouakchott, Mauritania, and Dakar, Senegal to respond to a harbor or shoreline incident in the area. In Senegal, we also have access to the WACAF aircraft described above. We will have access to additional Tier 2 and Tier 3 equipment from the Southampton, UK location.

Per common industry practice, under the agreements currently in place, or agreements we may enter into during the future, governing the terms of use of the drilling rigs contracted by us or our block partners, the drilling rig contractors indemnify us and our block partners in respect of pollution and environmental damage arising out of operations which originate above the surface of the water and from a drilling rig contractor's property, including, but not limited to, their drilling rig and other related equipment. Furthermore, pursuant to the terms of the operating agreements covering the blocks in which we or our block partners are currently drilling, except in certain circumstances, each block partner is responsible for the share of liabilities in proportion to its respective participating interest in the block 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, and liabilities incurred in connection with plugging or bringing under control any well. We maintain, or expect to maintain, upon commencement of drilling operations, 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 Jubilee FPSO. Our insurance is, or will be, carried in amounts typical for the industry and relative to our size and operations and in accordance with our contractual and regulatory obligations.

Other Regulation of the Oil and Gas Industry

Ghana

The Ghanaian Petroleum Law currently governs the upstream Ghanaian oil and natural gas regulatory regime and sets out the policy and framework for industry participants. All petroleum found in its natural state within Ghana is deemed to be national property and is to be developed on behalf of the people of Ghana. GNPC is empowered to carry out exploration and development work either on its own or in association with local or foreign contractors. Companies who wish to gain rights to explore and produce in Ghana can only do so by entering into a petroleum agreement with

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Ghana and GNPC. The law requires for the terms of the petroleum agreement to be negotiated and agreed between GNPC and oil and gas companies. The Parliament of Ghana has final approval rights over the negotiated petroleum agreement. Ghana's Ministry of Petroleum represents the state in its executive capacity. The Petroleum Commission is the regulatory body for the upstream petroleum industry and the advisor to the Ministry of Petroleum. GNPC has rights to undertake petroleum operations in any acreage declared open by Ghana's Ministry of Petroleum. As well, when petroleum operations are undertaken by GNPC under a petroleum contract, GNPC has a carried interest in each petroleum agreement and, following the declaration of any commercial discovery, such carried interest is typically subject to increase by a certain agreed upon amount at the option of GNPC. Petroleum agreements are required to include certain domestic supply requirements, including the sale to Ghana of oil for consumption in Ghana at international market prices.

The Ghanaian Petroleum Law and our Ghanaian petroleum agreements contain provisions restricting the direct or indirect assignment or transfer of such petroleum agreements or interests thereunder without the prior written consent of GNPC and the Ministry of Petroleum. The Ghanaian Petroleum Law also imposes certain restrictions on the direct or indirect transfer by a contractor of shares of its incorporated company in Ghana to a third party without the prior written consent of Ghana's Minister of Petroleum. The Ghanaian Tax Law may impose certain taxes upon the direct or indirect transfer of interests in the petroleum agreements or interests thereunder.

Ghana's Parliament is considering the enactment of a new Petroleum Exploration and Production Act and has enacted a Petroleum Revenue Management Act and the Petroleum Commission Act of 2011. The Petroleum Exploration and Production Act remains in a draft form, with industry comments having been submitted. The new Petroleum Revenue Management Act of 2011 pertains primarily to the collection, allocation, and management by the government of Ghana of the petroleum revenue. The Petroleum Commission Act created the Petroleum Commission, whose objective is to regulate and manage the use of petroleum resources and coordinate the policies thereto. The Petroleum Commission became effective in January 2012. Among the Petroleum Commission's functions are advising the Minister of Energy on matters such as appraisal plans, field development plans, recommending to the Minister national policies related to petroleum, and storing and managing data. We understand the primary purpose of the Petroleum Commission is to fulfill the regulatory functions previously undertaken by GNPC. We currently believe that such laws will only have prospective application, and as such will not modify the terms of (or interests under) the agreements governing our license interests in Ghana, including the WCTP and DT petroleum contracts (which include stabilization clauses) and the UUOA, and will not impose additional restrictions on the direct or indirect transfer of our license interests, including upon a change of control. The Petroleum (Local Content and Local Participation in Petroleum Activities) Regulations came into effect in February 2014. The Regulations mandate certain levels of local participation in service companies, in country manufacturing of goods and the provision of services, and certain reporting requirements.

Mauritania

The main legislative act in the Islamic Republic of Mauritania relevant to petroleum exploration and production is Law No. 2010 033 dated July 20, 2010 as amended (the "Hydrocarbon Laws"). The regulatory authority in Mauritania is the Ministry of Petroleum, Energy and Mines and the national oil company acting on its behalf is SMHPM. SMHPM was instituted by Decree No. 2005 106 of November 7, 2005 and modified by Decree No. 2009 168 of May 3, 2009 and Decree No. 2014 01 dated January 6, 2014. Pursuant to the Hydrocarbon Laws, Mauritania or SMHPM may undertake petroleum operations and may authorize other legal entities to undertake petroleum operations under petroleum contracts. The Ministry shall sign petroleum contracts on behalf of Mauritania. Assignments of interests in petroleum contracts also require the consent of the Ministry. The exploration period shall not be more than ten years, subject to certain permitted extensions and the exploitation period shall not be more than 25 years. Petroleum contracts may provide that Mauritania has a carried interest of up to 10% during the exploration period. Petroleum contracts shall grant Mauritania the option to participate for a percentage not less than 10% nor more than 14% in the rights of the contractor during the exploitation period.

Morocco (including Western Sahara)

The two main legislative acts in Morocco relevant to petroleum exploration and production are (i) the Law 21 90 (April 1, 1992) as amended and completed by the Law 27 99 (February 15, 2000) and (ii) the Decree 2 93 786 (November 3, 1993) as amended and completed by decree 2 99 210 (March 16, 2000) (together, “Morocco’s Petroleum

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Laws”). The regulatory authority in Morocco is the Ministry of Energy, Mines, Water and Environment and the national oil company acting on its behalf is ONHYM. ONHYM is a public establishment (établissement public) with the legal personality and financial autonomy created pursuant to the Law 33 01 (November 11, 2003) which was further completed by the Decree 2 04 372 (December 29, 2004).

Pursuant to the Law 21 90, the granting of an exploration permit is subject to the conclusion of a petroleum contract with the Moroccan State. Therefore, companies who wish to gain rights to explore and produce in Morocco can only do so by entering into a petroleum contract with ONHYM acting on behalf of the State. It is further provided that the State of Morocco (via ONHYM) shall retain a participation in exploration permits or exploitation concessions which shall not be in excess of 25%. More generally, ONHYM is representing the State of Morocco for licensing, exploration and exploitation matters within the limit of its prerogatives set out pursuant to the Law 33 01. Assignments of interests in exploration permits also require the consent of the administration pursuant to the Law 21 90.

The Sahrawi Arab Democratic Republic (the “SADR”) has claimed sovereignty over the Western Sahara territory, including the area offshore, and has issued exploration licenses which conflict with those issued by Morocco, including certain licenses which conflict with the Cap Boujdour Offshore block license issued to Kosmos. Other countries have formally recognized the SADR, but the UN has not. It is uncertain when and how Western Sahara’s sovereignty issues will be resolved.

Portugal

The primary legislative acts in Portugal relevant to petroleum exploration and production are Decree Law 109/94, of April 16, 1994—governing petroleum exploration and production activities (the “Petroleum Law”)—and Order 790/94, of September 5, 1994—concerning the standard terms for concession contracts. The main regulatory authorities in Portugal are the Ministry of Environment, Spatial Planning and Energy, the General Directorate for Energy and Geology (the “DGEG”) and the National Entity for the Fuel Market (“ENMC”). This latter entity is fairly recent and for that reason there is ambiguity between DGEG’s and ENMC’s powers and authority in respect of the upstream oil sector. DGEG’s authority derives from Decree Law 130/2014, of August 29, 2014—which approves DGEG’s organic statute—and ENMC’s from Decree Law 165/2013, of December 16, 2013—which created ENMC and defined its responsibilities. The award of petroleum exploration and production rights is made through concession contracts. As a general rule, the awarding procedure is a public tender. The assignment or transfer of interests in concession contracts (as well as transfers of 50% or more of the concessionaire’s share capital) requires the consent of the Minister.

Sao Tome and Principe

The Fundamental Law on Petroleum Operations, Law No. 16/2009 governs petroleum operations in Sao Tome and Principe, including the exploration, development and production of hydrocarbons and the marketing and transportation thereof. There is also the Petroleum Taxation Law, Law No. 15/2009. The ANP is established by Law No. 5/2004, and is responsible for the regulation, contracting and supervision of hydrocarbon operations in Sao Tome and Principe.

Senegal

The Petroleum Code of Senegal, Law No. 98 05 of January 8, 1998 governs petroleum operations in Senegal, including the exploration, development and production of hydrocarbons and the marketing and transportation thereof, as well as the rights of landowners. The implementing decree is No 98 810 of October 6, 1998. The Ministry in charge of Energy grants or denies applications for petroleum agreements, and such are granted by decree. Any amendment to the petroleum agreements requires the consent of the Minister. The Senegalese national oil company, Societe des Petroles du Senegal (“PETROSEN”), as the regulatory body tasked with both upstream and downstream missions, is under the supervision of the Ministry of Energy. PETROSEN prepares and negotiates all hydrocarbon licenses and contracts. PETROSEN has a carried interest during the exploration phase. The assignment of interests in petroleum contracts, as well as amendments thereto, require the consent of the Minister.

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Suriname

The three sets of rules governing petroleum exploration and production in Suriname are (i) Staatsolie's Concession Agreement (Decree E8 B, Official Gazette 1981 no. 59), (ii) the Mining Decree of 1986 (Official Gazette 1986 no. 28) and (iii) the Petroleum Law 1990 (Official Gazette 1991 no. 7, as amended in 2001).

The Mining Decree granted concession rights for petroleum activities to state enterprises. Staatsolie, the national oil company, was founded in 1980 as a state enterprise and holds mining rights onshore and offshore in Suriname. The Suriname Petroleum Law granted state enterprises with petroleum concession rights the authority, upon the approval of the Minister of Natural Resources, to enter into petroleum contracts with E&P companies. Therefore, companies who wish to gain rights to explore and produce in Suriname can only do so by entering into a petroleum contract with Staatsolie, subject to approval by the Minister of Natural Resources. Assignments of interests in petroleum contracts also require the consent of Staatsolie and/or The Minister of Natural Resources.

Certain Bermuda Law Considerations

As a Bermuda exempted company, we are subject to regulation in Bermuda. Among other things, we must comply with the provisions of the Bermuda Companies Act regulating the payment of dividends and making of distributions from contributed surplus.

We have been designated by the Bermuda Monetary Authority as a non resident for Bermuda exchange control purposes. This designation allows us to engage in transactions in currencies other than the Bermuda dollar, and there are no restrictions on our ability to transfer funds (other than funds denominated in Bermuda dollars) in and out of Bermuda or to pay dividends to United States residents who are holders of our common shares.

Under Bermuda law, "exempted" companies are companies formed for the purpose of conducting business outside Bermuda from a principal place of business in Bermuda. As an exempted company, we may not, without a license or consent granted by the Minister of Finance, participate in certain business transactions, including transactions involving Bermuda landholding rights and the carrying on of business of any kind for which we are not licensed in Bermuda.

Employees

As of December 31, 2015, we had approximately 260 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

We were incorporated pursuant to the laws of Bermuda as Kosmos Energy Ltd. in January 2011 to become a holding company for Kosmos Energy Holdings. Kosmos Energy Holdings was formed as an exempted company limited by guarantee pursuant to the laws of the Cayman Islands in March 2004. Pursuant to the terms of a corporate reorganization that was completed simultaneously with the closing of our initial public offering, all of the interests in Kosmos Energy Holdings were exchanged for newly issued common shares of Kosmos Energy Ltd. and as a result, Kosmos Energy Holdings became a wholly owned subsidiary of Kosmos Energy Ltd.

We maintain a registered office in Bermuda at Clarendon House, 2 Church Street, Hamilton HM 11, Bermuda. The telephone number of our registered offices is (441) 295 5950. Our U.S. subsidiary maintains its headquarters at 8176 Park Lane, Suite 500, Dallas, Texas 75231 and its telephone number is (214) 445 9600.

Available Information

Kosmos is listed on the New York Stock Exchange and our common shares are traded under the symbol KOS. We file or furnish annual, quarterly and current reports, proxy statements and other information with the SEC. The

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public may read and copy any reports, statements or other information at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information about the operation of the public reference room by calling the SEC at 1 800 SEC 0330. In addition, the SEC maintains a website at http://www.sec.gov that contains documents we file electronically with the SEC.

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 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 Ghana, an area in which we focus a substantial amount of our appraisal and development efforts, has only recently been considered economically viable for hydrocarbon production due to the costs and difficulties involved in drilling for oil at such depths and the relatively recent discovery of commercial quantities of oil in the region. Likewise, our deepwater offshore Morocco (including Western Sahara), Portugal, Sao Tome and Principe, Senegal, Suriname and Mauritania 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 unappraised 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.

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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 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 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. Exploratory wells bear a much greater risk of loss 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, 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.

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Our identified drilling locations are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management team has identified and scheduled drilling locations on our license 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 partners and regulators, seasonal conditions, oil prices, assessment of risks, costs and drilling results. The final determination on whether to drill 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 activities with respect to our established drilling locations. Because of these uncertainties, we do not know if the drilling locations we have identified will be drilled 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 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 have recently experienced significant and sustained declines 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 price and availability of competitors’ supplies of oil and natural gas; and
- the price, availability or mandated use of alternative fuels.

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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 agreements and licenses, our interests in the undeveloped parts of our license areas may lapse. Should the prospects we have identified in this annual report on Form 10 K under the license agreements currently in place yield discoveries, we cannot assure you that we will not face delays in drilling 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, 2015, we have unfulfilled drilling obligations in our Essaouria and Senegal 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 WCTP and DT Block 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 sell to an energy 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 are subject to redetermination and our interests in such unit may decrease as a result.

The interests in and development of the Jubilee Field are governed by the terms of the UUOA. The parties to the 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 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 UUOA will not negatively affect our interests in the Jubilee 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 do not, and may not in the future, hold all of the working interests in certain of our license areas. Therefore, we will not be able to control the timing of exploration or development efforts, associated costs, or 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 Unit Operator on the Jubilee Unit and do not hold operatorship in one of our two blocks offshore Ghana (the DT Block). In addition, the terms of the UUOA governing the unit partners' interests in the Jubilee Unit require certain actions be approved by at least 80% of the unit voting interests and the terms of our other current or future license or venture agreements may require at least the majority of working interests to approve certain actions. 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 operated by our block partners will depend on a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- 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;

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· selection of technology; and
· the rate of production of reserves, if any.

This limited ability to exercise control over the operations on some of 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, 2015.

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

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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. If oil prices decline by $1.00 per Bbl from prices used in calculating such estimates, then the PV 10 and the Standardized Measure as of December 31, 2015 would each decrease by approximately $51.5 million. Oil prices have recently experienced significant declines. 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 and develop 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 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 larger 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

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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. 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 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.

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In Ghana, we currently produce associated gas from the Jubilee Field. A gas pipeline from the Jubilee Field has been constructed to transport such natural gas for processing and sale. However, we granted the first 200 Bcf of natural gas from the Jubilee Phase 1 to Ghana at no cost. Through December 31, 2015, Ghana has received approximately 26 Bcf. Thus, in Ghana, even if additional infrastructure was in place for natural gas processing and sales, it would still be quite some time before we would be able to commercialize our Ghana natural gas. As a result, we do not have proved gas reserves associated with future natural gas sales from Jubilee Field in Ghana.

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 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 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 on line, potentially resulting in decreased production and increased remediation costs.

Additionally, the future exploitation and sale of associated and non associated natural gas and liquids 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 to transport such natural gas to the mainland for processing and sale. However, the uptime of the facility during 2016 and in future periods is not known. In the absence of the continuous removal of large quantities of natural gas from the Jubilee Field it is anticipated that we will need to flare such natural gas in order to maintain crude oil production. Currently, we have not been issued an amended permit from the Ghana EPA to flare natural gas produced from the Jubilee Field in substantial quantities. If we are unable to resolve potential issues related to the continuous removal of associated natural gas in large quantities from the Jubilee Field, 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. 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 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, 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.

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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 operating risks, including, but not limited to:

- fires, blowouts, spills, cratering and explosions;
- mechanical and equipment problems, including unforeseen engineering complications. For example, following a February 2016 inspection of the turret area of the Jubilee field FPSO, by SOFEC, the original turret manufacturer, a potential issue was identified with the turret bearing. As a precautionary measure, additional operating procedures to monitor the turret bearing and reduce the degree of rotation of the vessel are being put in place. SOFEC will now undertake further offshore examinations and Tullow, operator of the Jubilee Unit, will work with SOFEC to determine what further measures will be required;
- 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, other 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. In accordance with customary industry practice, 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.

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.

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Our offshore and deepwater operations will 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 our water injection facilities on the FPSO and water and gas injection wells. This equipment downtime 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 of and the high cost of this infrastructure, further discoveries we may make in Africa, South America and Europe 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 for us, and have a significant negative impact on our earnings, cash flows, liquidity, financial position, and stock price.

We have had disagreements with the Republic of Ghana and the Ghana National Petroleum Corporation regarding certain of our rights and responsibilities under the WCTP and DT Petroleum Agreements.

Multiple discovered fields and all of our proved reserves are located offshore Ghana. The WCTP petroleum contract, the DT petroleum contract and the UUOA cover the two blocks and the Jubilee Unit 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 and/or Ghana’s Ministry of Petroleum. We have previously had disagreements with the Ministry of Petroleum and GNPC regarding certain of our rights and responsibilities under these petroleum contracts, the 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 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. These past disagreements have been resolved. The resolution of certain of these disagreements required us to pay agreed settlement costs to GNPC and/or the government of Ghana.

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 or development activities, our ability to operate, our rights under our licenses and local laws or our rights to monetize our interests.

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The geographic locations of our licenses in Africa, South America and Europe subject us to an increased risk of loss of revenue or curtailment of production from factors specifically affecting those areas.

Our current exploration licenses are located in Africa, South America and Europe. 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 or civil unrest; 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 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 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 or approvals, 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 Ghanaian Revenue Authority (the “GRA”) has disputed certain tax deductions we have 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.

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.

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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, 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 States, the United Kingdom, Bermuda 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.

A portion of our asset portfolio is in Western Sahara, and we could be adversely affected by the political, economic and military conditions in that region. Our exploration licenses in this region conflict with exploration licenses issued by the Sahrawi Arab Democratic Republic (SADR).

Morocco claims the territory of Western Sahara, where our Cap Boujdour Offshore block is geographically located, as part of the Kingdom of Morocco, and it has de facto administrative control of approximately 80% of Western Sahara. However, Western Sahara is on the United Nations (the "UN") list of Non Self Governing territories, and the territory's sovereignty has been in dispute since 1975. The Polisario Front, representing the SADR, has a conflicting claim of sovereignty over Western Sahara. No countries have formally recognized Morocco's claim to Western Sahara, although some countries implicitly support Morocco's position. Other countries have formally recognized the SADR, but the UN has not. A UN administered cease fire has been in place since 1991, and while there have been intermittent UN sponsored talks, between Morocco and SADR (represented by the Polisario Front), the dispute remains stalemated. It is uncertain when and how Western Sahara's sovereignty issues will be resolved.

We own a 55% participating interest in the Cap Boujdour Offshore block located geographically offshore Western Sahara. Our license was granted by the government of Morocco; however, the SADR has issued its own offshore exploration licenses which, in some areas, conflict with our licenses. As a result of SADR's conflicting claim of rights to oil and natural gas licenses granted by Morocco, and the SADR's claims that Morocco's exploitation of Western Sahara's natural resources violates international law, our interests could decrease in value or be lost. Any political instability, terrorism, changes in government, or escalation in hostilities involving the SADR, Morocco or neighboring states could adversely affect our operations and assets. In addition, Morocco has recently experienced political and social disturbances that could affect its legal and administrative institutions. A change in U.S. foreign policy or the policies of other countries regarding Western Sahara could also adversely affect our operations and assets. We are not insured against political or terrorism risks because management deems the premium costs of such insurance to be currently prohibitively expensive relative to the limited coverage provided thereby.

Furthermore, various activist groups have mounted public relations campaigns to force companies to cease and divest operations in Western Sahara, and we could come under similar public pressure. Some investors have refused to invest in companies with operations in Western Sahara, and we could be subject to similar pressure. Any of these factors could have a negative impact on our stock price and a material adverse effect on our results of operations and financial condition.

A maritime boundary demarcation between Côte D'Ivoire and Ghana may affect a portion of our license areas offshore Ghana.

The historical maritime boundary between Ghana and its western neighbor, the Republic of Côte d'Ivoire, forms the western boundary of the DT Block offshore Ghana. In early 2010, Côte d'Ivoire petitioned the United Nations to demarcate the Ivorian territorial maritime boundary with Ghana. In response to the petition, Ghana established a Boundary Commission to undertake negotiations with Côte d'Ivoire in an effort to resolve their respective maritime boundary. The Ivorian Government then issued a map in September 2011, which reflected potential petroleum license areas that overlap with the DT Block. In September 2014, Ghana submitted the matter to arbitration under the United Nations Convention on the Law of the Sea, and in December 2014, the two parties agreed to transfer the dispute to the ITLOS. On January 12, 2015, the ITLOS formed a special chamber to address the maritime boundary dispute.

On March 2, 2015, Côte D'Ivoire applied to the ITLOS for a provisional measures order suspending activities in the disputed area in which the TEN development is located until the substantive case concerning the border dispute is adjudicated. More specifically, the provisional measures application asked that Ghana be ordered to: (i) suspend all ongoing exploration and exploitation operations in the disputed area, (ii) refrain from granting any authorizations for new exploration and exploitation in the disputed area, (iii) not use any data acquired in the disputed area in any way that would be detrimental to Côte d'Ivoire, and (iv) take any necessary action for the preservation of the continental shelf, its water, and its underground in the disputed area.

In late April 2015, the Special Chamber of ITLOS issued its order in response to Côte d'Ivoire's provisional measures application. In its order, ITLOS rejected Côte d'Ivoire's requests that Ghana suspend its ongoing exploration and development operations in the disputed area but ordered Ghana to: (i) take all necessary steps to ensure that no new drilling either by Ghana or any entity or person under its control takes place in the disputed area; (ii) take all necessary steps to prevent information resulting from past, ongoing or future exploration activities conducted by Ghana, or with its authorization, in the disputed area that is not already in the public domain from being used in any way whatsoever to the detriment of Cote d'Ivoire; (iii) carry out strict and continuous monitoring of all activities undertaken by Ghana or with its authorization in the disputed area with a view to ensuring the prevention of serious harm to the marine environment; (iv) take all necessary steps to prevent serious harm to the marine environment, including the continental shelf and its superjacent waters, in the disputed area and shall cooperate to that end; and (v) pursue cooperation with Côte d'Ivoire and refrain from any unilateral action that might lead to aggravating the dispute. On June 11, 2015, the Ghana Attorney General issued a letter to the DT Operator, which confirmed the DT Block partners may (i) continue to drill wells that had been started but not completed prior to the ITLOS order and (ii) carry out completion work on wells that have already been drilled. The TEN development is currently estimated to be 80 percent complete. We expect the TEN development activities will continue as planned with first oil expected in the third quarter of 2016. With respect to the Wawa Discovery, we plan to discuss with the Government of Ghana the effects of the ITLOS order on the proposed Wawa appraisal activities so that we can more clearly define our future plans and corresponding timeline.

We do not know if the maritime boundary dispute will change our and our block partners' rights to develop our discoveries within such areas. In the event that the ITLOS proceedings result in an unfavorable outcome for Ghana, our operations within such areas could be materially impacted.

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.

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Participants in the oil and gas industry are subject to numerous laws 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
- 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 and is considering the enactment of a new Petroleum Exploration and Production Act. 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 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. See "Item 1. Business—Other Regulation of the Oil and Gas Industry—Ghana."

The SEC promulgated final rules under the Dodd Frank Act requiring SEC reporting companies that engage in the commercial development of oil, natural gas or minerals, to disclose payments (including taxes, royalties, fees and other amounts) made by such companies or an entity controlled by such companies to the United States or to any non U.S. government for the purpose of commercial development of oil, natural gas or minerals. The final rules do not contain an exception that would allow companies to exclude payments which may not be disclosed pursuant to foreign laws or confidentiality agreements. However, in July 2013, the United States District Court for the District of Columbia vacated the final rules. The SEC has proposed revised rules implementing the applicable section of the Dodd Frank Act however, such rules have not been approved. There can be no assurance that we will be able to comply with these regulations, once promulgated, without creating disagreements with these partners or governments. Further, such regulations may place us at a disadvantage to our non U.S. competitors in doing business in the international oil and gas industry. Any of these consequences could have a material adverse effect on our financial condition and our results of operations.

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

We are subject to various international, foreign, federal, state and local environmental, health and safety 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. 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 discoveries and prospects, could be held liable for some or all environmental, health and safety 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 environmental, health or safety 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 environmental, health or safety 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, on December 12, 2015, 195 nations finalized the text of an international climate change accord in Paris, France (the “Paris Agreement”), which nations may sign and officially enter into beginning in April 2016. The Paris Agreement calls for 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, Morocco (including Western Sahara), Portugal, Sao Tome and Principe, Senegal and Suriname, are parties. While the Kyoto Protocol was set to expire in 2012, it has been extended by amendment until 2020. 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. 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.

Environmental, health and safety laws are complex, change frequently and have tended to become increasingly stringent over time. Our costs of complying with current and future climate change, environmental, health and safety laws, the actions or omissions of our block partners and third party contractors and our liabilities arising from releases of,

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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, 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;
- 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.

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 liabilities under the U.S. Foreign Corrupt Practices Act and other anti corruption laws, and any determination that we violated the U.S. Foreign Corrupt Practices Act or other such laws could 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 2011, 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 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.

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 shares. 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

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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.

The recovery from the global economic crisis of 2008 and resulting recession has been slow and uneven. Market volatility and reduced consumer demand have increased economic uncertainty, and the current global economic growth rate is slower than what was experienced in the decade preceding the crisis. 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 currently, and 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.

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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, revolving credit facility and letter of 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 and, in the case of the letter of credit facility, the breach of any of the applicable covenants could result in a default, in which case the cash collateral we are required to maintain under the letter of credit facility would increase from 75% to 100% of all outstanding letters of credit, and if such additional cash is not posted, the lenders thereunder could elect to declare all amounts outstanding thereunder, 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, letter of 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, the letter of 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 shares of an opportunity to sell their common shares at a premium over prevailing market prices.

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

At December 31, 2015, we had $400.0 million outstanding and $1.1 billion of committed undrawn capacity under our commercial debt facility, subject to borrowing base availability. As of December 31, 2015, there were no borrowings outstanding under the Corporate Revolver and the undrawn availability was $400.0 million. As of December 31, 2015, there were nine outstanding letters of credit totaling $15.3 million under the letter of credit facility agreement and $525.0 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

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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 their intermediate parent companies (other than Kosmos Energy Holdings) 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.

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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 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 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.

Our bye laws contain a provision renouncing our interest and expectancy in certain corporate opportunities, which could adversely affect our business or future prospects.

Our bye laws provide that, to the fullest extent permitted by applicable law, we renounce any right, interest or expectancy in, or in being offered an opportunity to participate in, any business opportunity that may be from time to time be presented to certain of our affiliates or any of their respective officers, directors, agents, shareholders, members, partners, affiliates and subsidiaries (other than us and our subsidiaries) or business opportunities that such parties participate in or desire to participate in, even if the opportunity is one that we might reasonably have pursued or had the ability or desire to pursue if granted the opportunity to do so, and no such person shall be liable to us for breach of any statutory, fiduciary, contractual or other duty, as a director or otherwise, by reason of the fact that such person pursues or acquires any such business opportunity, directs any such business opportunity to another person or fails to present any such business opportunity, or information regarding any such business opportunity, to us unless, in the case of any such person who is our director, such person fails to present any business opportunity that is expressly offered to such person solely in his or her capacity as our director.

As a result, our directors and certain of our affiliates and their respective affiliates may become aware, from time to time, of certain business opportunities, such as acquisition opportunities, and may direct such opportunities to other businesses in which they or their affiliates have invested, in which case we may not become aware of or otherwise have the ability to pursue such opportunity. Further, such businesses may choose to compete with us for these opportunities. As a result, our renouncing of our interest and expectancy in any business opportunity that may be from time to time presented to our directors and certain of our affiliates and their respective affiliates could adversely impact our business or future prospects if attractive business opportunities are procured by such parties for their own benefit rather than for ours.

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We receive certain beneficial tax treatment as a result of being an exempted company incorporated pursuant to the laws of Bermuda. Changes in that treatment could have a material adverse effect on our net income, our cash flow and our financial condition.

We are an exempted company incorporated pursuant to the laws of Bermuda and operate through subsidiaries in a number of countries throughout the world. Consequently, we are subject to changes in tax laws, treaties or regulations or the interpretation or enforcement thereof in the United States, Bermuda, Ghana, and other jurisdictions in which we or any of our subsidiaries operate or are resident. In the past, legislation has been introduced in the Congress of the United States that would reform the U.S. tax laws as they apply to certain non U.S. entities and operations, including legislation that would treat a foreign corporation as a U.S. corporation for U.S. federal income tax purposes if substantially all of its senior management is located in the United States. If this or similar legislation is passed that changes our U.S. tax position, it could have a material adverse effect on our net income, our cash flow and our financial condition.

We may become subject to taxes in Bermuda after March 31, 2035, which may have a material adverse effect on our results of operations.

The Bermuda Minister of Finance, under the Exempted Undertakings Tax Protection Act 1966 of Bermuda, as amended, has given us an assurance that if any legislation is enacted in Bermuda that would impose tax computed on profits or income, or computed on any capital asset, gain or appreciation, or any tax in the nature of estate duty or inheritance tax, then the imposition of any such tax will not be applicable to us or any of our operations, shares, debentures or other obligations until March 31, 2035, except insofar as such tax applies to persons who ordinarily reside in Bermuda or to any taxes payable by us in respect of real property owned or leased by us in Bermuda.

The impact of Bermuda's letter of commitment to the Organization for Economic Cooperation and Development to eliminate harmful tax practices is uncertain and could adversely affect our tax status in Bermuda.

The Organization for Economic Cooperation and Development ("OECD") has published reports and launched a global initiative among member and non member countries on measures to limit harmful tax competition. These measures are largely directed at counteracting the effects of tax havens and preferential tax regimes in countries around the world. According to the OECD, Bermuda is a jurisdiction that has substantially implemented the internationally agreed tax standard and as such is listed on the OECD "white" list. However, we are not able to predict whether any changes will be made to this classification or whether such changes will subject us to additional taxes.

The adoption of financial reform legislation by the United States Congress in 2010, and its implementing regulations, 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 United States Congress adopted comprehensive financial reform legislation in 2010 that establishes federal oversight and regulation of the over the counter derivatives market and entities, such as ours, that participate in that market. The Dodd Frank Act was signed into law by the President on July 21, 2010. The Commodity Futures Trading Commission ("CFTC"), which has jurisdiction over derivatives instruments that are "swaps," has implemented many, but not all, of these provisions through regulations; the SEC, which regulates "security-based swaps" has proposed but not finalized most of its implementing regulations.

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. It is not possible at this time to predict when the CFTC will finalize 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

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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.

The Dodd Frank Act and its implementing regulations 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.

We may become a “passive foreign investment company” for U.S. federal income tax purposes, which could create adverse tax consequences for U.S. investors.

U.S. investors that hold stock in a “passive foreign investment company” (“PFIC”) are subject to special rules that can create adverse U.S. federal income tax consequences, including imputed interest charges and recharacterization of certain gains and distributions. Based on management estimates and projections of future revenue, we do not believe that we will be a PFIC for the current taxable year and we do not expect to become one in the foreseeable future. Because PFIC status is a factual determination that is made annually and thus is subject to change, there can be no assurance that we will not be a PFIC for any taxable year.

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.

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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. 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 in the geographies in which we operate may adversely affect 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 occured 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 the Ebola virus continue to spread or should another 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, including Ghana, 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 the Ebola epidemic spread to Ghana, access to the FPSO operating at the Jubilee Field could be restricted and/or terminated. The FPSO is 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 Jubilee Field would likely be required to cease production and other operations until such restrictions were lifted.

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Risks Relating to Our Common Shares

Our share price may be volatile, and purchasers of our common shares 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 shares 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 Bermuda, 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 shares or changes in financial estimates by analysts;
- the inability to meet the financial estimates of analysts who follow our common shares;
- 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 shares may be sold into the market at any time. This could cause the market price of our common shares 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 common shares 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 common shares 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 our common shares, or the perception in the market that the holders of a large number of shares intend to sell common shares, could reduce the market price of our common shares.

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The concentration of our share capital ownership among our largest shareholders, and their affiliates, will limit your ability to influence corporate matters.

Our two largest shareholders collectively own approximately 55% of our issued and outstanding common shares. Consequently, these shareholders have significant influence over all matters that require approval by our shareholders, including the election of directors and approval of significant corporate transactions. This concentration of ownership will limit your ability to influence corporate matters, and as a result, actions may be taken that you may not view as beneficial.

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

We may issue additional common shares, 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 common shares 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 common shares in the future, it may have a dilutive effect on our current outstanding shareholders.

We are a “controlled company” within the meaning of the NYSE rules and, as a result, qualify for and rely on exemptions from certain corporate governance requirements.

Funds affiliated with Warburg Pincus LLC and The Blackstone Group L.P., respectively, continue to control a majority of the voting power of our issued and outstanding common shares, and we are a “controlled company” within the meaning of the NYSE corporate governance standards. Under the NYSE rules, a company of which more than 50% of the voting power is held by another person or group of persons acting together is a “controlled company” and may elect not to comply with certain NYSE corporate governance requirements, including the requirements that:

· a majority of the board of directors consist of independent directors;
· the nominating and corporate governance committee be composed entirely of independent directors with a written charter addressing the committee’s purpose and responsibilities;
· the compensation committee be composed entirely of independent directors with a written charter addressing the committee’s purpose and responsibilities; and
· there be an annual self assessment evaluation of the nominating and corporate governance and compensation committees.

We have elected to be treated as a controlled company and utilize these exemptions, including the exemption for a board of directors composed of a majority of independent directors. In addition, although we have adopted charters for our audit, nominating and corporate governance and compensation committees and conduct annual self assessments for these committees, currently, only our audit committee is composed entirely of independent directors. Accordingly, you may not have the same protections afforded to shareholders of companies that are subject to all of the NYSE corporate governance requirements.

We do not intend to pay dividends on our common shares and, consequently, your only opportunity to achieve a return on your investment is if the price of our shares appreciates.

We do not plan to declare dividends on shares of our common shares in the foreseeable future. Additionally, certain of our subsidiaries are currently restricted in their ability to pay dividends to us pursuant to the terms of our commercial debt facility unless they meet certain conditions, financial and otherwise. Consequently, investors must rely on sales of their common shares after price appreciation, which may never occur, as the only way to realize a return on their investment.

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We are a Bermuda company and a significant portion of our assets are located outside the United States. As a result, it may be difficult for shareholders to enforce civil liability provisions of the federal or state securities laws of the United States.

We are a Bermuda exempted company. As a result, the rights of holders of our common shares will be governed by Bermuda law and our memorandum of association and bye laws. The rights of shareholders under Bermuda law may differ from the rights of shareholders of companies incorporated in other jurisdictions. Some of our directors are not residents of the United States, and a substantial portion of our assets are located outside the United States. As a result, it may be difficult for investors to effect service of process on that person in the United States or to enforce in the United States judgments obtained in U.S. courts against us or that person based on the civil liability provisions of the U.S. securities laws. It is doubtful whether courts in Bermuda will enforce judgments obtained in other jurisdictions, including the United States, against us or our directors or officers under the securities laws of those jurisdictions or entertain actions in Bermuda against us or our directors or officers under the securities laws of other jurisdictions.

Bermuda law differs from the laws in effect in the United States and might afford less protection to shareholders.

Our shareholders could have more difficulty protecting their interests than would shareholders of a corporation incorporated in a jurisdiction of the United States. As a Bermuda company, we are governed by the Companies Act 1981 of Bermuda (the "Bermuda Companies Act"). The Bermuda Companies Act differs in some material respects from laws generally applicable to U.S. corporations and shareholders, including the provisions relating to interested directors, mergers and acquisitions, takeovers, shareholder lawsuits and indemnification of directors. Set forth below is a summary of these provisions, as well as modifications adopted pursuant to our bye laws, which differ in certain respects from provisions of Delaware corporate law. Because the following statements are summaries, they do not discuss all aspects of Bermuda law that may be relevant to us and our shareholders.

Interested Directors. Under Bermuda law and our bye laws, as long as a director discloses a direct or indirect interest in any contract or arrangement with us as required by law, such director is entitled to vote in respect of any such contract or arrangement in which he or she is interested, unless disqualified from doing so by the chairman of the meeting, and such a contract or arrangement will not be voidable solely as a result of the interested director's participation in its approval. In addition, the director will not be liable to us for any profit realized from the transaction. In contrast, 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 corporation 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.

Mergers and Similar Arrangements. The amalgamation of a Bermuda company with another company or corporation (other than certain affiliated companies) requires the amalgamation agreement to be approved by the company's board of directors and by its shareholders. Unless the company's bye laws provide otherwise, the approval of 75% of the shareholders voting at such meeting is required to approve the amalgamation agreement, and the quorum for such meeting must be two persons holding or representing more than one third of the issued shares of the company. Our bye laws provide that an amalgamation (other than with a wholly owned subsidiary, per the Bermuda Companies Act) that has been approved by the board must only be approved by shareholders owning a majority of the issued and outstanding shares entitled to vote. Under Bermuda law, in the event of an amalgamation of a Bermuda company with another company or corporation, a shareholder of the Bermuda company who is not satisfied that fair value has been offered for such shareholder's shares may, within one month of notice of the shareholders meeting, apply to the Supreme Court of Bermuda to appraise the fair value of those shares. Under Delaware law, with certain exceptions, a merger, consolidation or sale of all or substantially all the assets of a corporation must be approved by the board of directors and a majority of the issued and outstanding shares entitled to vote thereon. Under Delaware law, a shareholder of a corporation participating in certain major corporate transactions may, under certain circumstances, be entitled to appraisal rights pursuant to which such shareholder may receive cash in the amount of the fair value of the shares held by such shareholder (as determined by a court) in lieu of the consideration such shareholder would otherwise receive in the transaction.

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Shareholders' Suit. Class actions and derivative actions are generally not available to shareholders under Bermuda law. The Bermuda courts, however, would ordinarily be expected to permit a shareholder to commence an action in the name of a company to remedy a wrong to the company where the act complained of is alleged to be beyond the corporate power of the company or illegal, or would result in the violation of the company's memorandum of association or bye laws. Furthermore, consideration would be given by a Bermuda court to acts that are alleged to constitute a fraud against the minority shareholders or where an act requires the approval of a greater percentage of the company's shareholders than that which actually approved it.

When the affairs of a company are being conducted in a manner which is oppressive or prejudicial to the interests of some part of the shareholders, one or more shareholders may apply to the Supreme Court of Bermuda, which may make such order as it sees fit, including an order regulating the conduct of the company's affairs in the future or ordering the purchase of the shares of any shareholders by other shareholders or by the company.

Our bye laws contain a provision by virtue of which we and our shareholders waive any claim or right of action that they have, both individually and on our behalf, against any director or officer in relation to any action or failure to take action by such director or officer, except in respect of any fraud or dishonesty of such director or officer. Class actions and derivative actions generally are available to shareholders under Delaware law for, among other things, breach of fiduciary duty, corporate waste and actions not taken in accordance with applicable law. In such actions, the court has discretion to permit the winning party to recover attorneys' fees incurred in connection with such action.

Indemnification of Directors. We may indemnify our directors and officers in their capacity as directors or officers for any loss arising or liability attaching to them by virtue of any rule of law in respect of any negligence, default, breach of duty or breach of trust of which a director or officer may be guilty in relation to the company other than in respect of his own fraud or dishonesty. Under Delaware law, a corporation may indemnify a director or officer of the corporation against expenses (including attorneys' fees), judgments, fines and amounts paid in settlement actually and reasonably incurred in defense of an action, suit or proceeding by reason of such position if such director or officer acted in good faith and in a manner he or she reasonably believed to be in or not opposed to the best interests of the corporation and, with respect to any criminal action or proceeding, such director or officer had no reasonable cause to believe his or her conduct was unlawful. In addition, we have entered into customary indemnification agreements with our directors.

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 Note 15 of Notes to the Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" 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.

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PART II

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

Common Shares Trading Summary

Our common shares are traded on the NYSE under the symbol KOS. The following table shows the quarterly high and low sale prices of our common shares.

	2015		2014	
	High	Low	High	Low
First Quarter	$ 9.32	$ 7.58	$ 11.60	$ 9.88
Second Quarter	10.03	7.94	11.27	10.00
Third Quarter	8.44	5.34	11.23	9.24
Fourth Quarter	8.00	4.62	10.41	6.96

As of February 16, 2016, based on information from the Company's transfer agent, Computershare Trust Company, N.A., the number of holders of record of Kosmos' common shares was 122. On February 16, 2016, the last reported sale price of Kosmos' common shares, as reported on the NYSE, was $3.94 per share.

We have never paid any dividends on our common shares. At the present time, we intend to retain all of our future earnings, if any, generated by our operations for the development and growth of our business. Additionally, we are subject to Bermuda legal constraints that may affect our ability to pay dividends on our common shares and make other payments. Under the Bermuda Companies Act, we may not declare or pay a dividend if there are reasonable grounds for believing that we are, or would after the payment be, unable to pay our liabilities as they become due or that the realizable value of our assets would thereafter be less than the aggregate of our liabilities, issued share capital and share premium accounts. Certain of our subsidiaries are also 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. Currently we do not anticipate paying any dividends in the foreseeable future.

Issuer Purchases of Equity Securities

Under the terms of our Long Term Incentive Plan ("LTIP"), we have issued shares of restricted shares and restricted share units to our employees. On the date that these restricted shares and restricted share units vest, we provide such employees the option to withhold, via a net exercise provision pursuant to our applicable restricted share award agreements and the LTIP, the number of vested shares (based on the closing price of our common shares on such vesting date) equal to the minimum statutory tax liability owed by such grantee. The shares withheld from the grantees to settle their tax liability are reallocated to the number of shares available for issuance under the LTIP. The following table outlines the total number of shares withheld during fiscal year 2015 and the average price paid per share.

	Total Number of Shares Withheld/Purchased (In thousands)	Average Price Paid per Share
January 1, 2015—January 31, 2015	—	$ —

February 1, 2015—February 28, 2015	1	8.77
March 1, 2015—March 31, 2015	4	8.98
April 1, 2015—April 30, 2015	196	9.53
May 1, 2015—May 31, 2015	1,470	9.31
June 1, 2015—June 30, 2015	23	8.87
July 1, 2015—July 31, 2015	—	—
August 1, 2015—August 31, 2015	—	—
September 1, 2015—September 30, 2015	—	—
October 1, 2015—October 31, 2015	5	5.67
November 1, 2015—November 30, 2015	2	6.86
December 1, 2015—December 31, 2015	—	—

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Total	1,701	9.32

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 period from May 11, 2011 (date our common shares commenced trading on the NYSE) through December 31, 2015, in cumulative total stockholder return on our common shares as measured against the cumulative total return of the S&P 500 Index and the SIG Oil Exploration & Production Index. The graph tracks the performance of a $100 investment in our common shares and in each index (with the reinvestment of all dividends).

		December 31,				
	May 11, 2011	2011	2012	2013	2014	2015
Kosmos Energy Ltd. (KOS)	$ 100.00	$ 68.11	$ 68.61	$ 62.11	$ 46.61	$ 28.89
S&P 500 (SPX)	100.00	94.55	109.36	143.24	161.77	163.86
SIG Oil Exploration & Production Index (EPX)	100.00	84.33	78.53	99.03	71.71	40.71

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Item 6. Selected Financial Data

The following selected consolidated financial information set forth below as of and for the five years ended, December 31, 2015, 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,				
	2015	2014	2013	2012	2011(1)
	(In thousands, except per share data)				
Revenues and other income:					
Oil and gas revenue	$ 446,696	$ 855,877	$ 851,212	$ 667,951	$ 666,912
Gain on sale of assets	24,651	23,769	—	—	—
Other income	209	3,092	941	3,150	775
Total revenues and other income	471,556	882,738	852,153	671,101	667,687
Costs and expenses:					
Oil and gas production	105,336	100,122	96,791	95,109	83,551
Exploration expenses	156,203	93,519	230,314	100,652	128,753
General and administrative	136,809	135,231	158,421	157,087	111,235
Depletion and depreciation	155,966	198,080	222,544	185,707	140,469
Interest and other financing costs, net	37,209	45,548	47,590	65,425	132,492
Derivatives, net	(210,649)	(281,853)	17,027	31,490	11,777
Restructuring charges	—	11,742	—	—	—
Doubtful accounts expense	—	—	—	—	(39,782)
Other expenses, net	5,246	2,081	3,512	1,475	149
Total costs and expenses	386,120	304,470	776,199	636,945	568,644
Income before income taxes	85,436	578,268	75,954	34,156	99,043
Income tax expense	155,272	298,898	166,998	101,184	76,686
Net income (loss)	$ (69,836)	$ 279,370	$ (91,044)	$ (67,028)	$ 22,357
Accretion to redemption value of convertible preferred units	—	—	—	—	(24,442)
Net income (loss) attributable to common shareholders	$ (69,836)	$ 279,370	$ (91,044)	$ (67,028)	$ (2,085)
Net income (loss) per share attributable to common shareholders (the year ended December 31, 2011 represents the period from May 16, 2011 to December 31, 2011)(2):					
Basic	$ (0.18)	$ 0.73	$ (0.24)	$ (0.18)	$ 0.09
Diluted	$ (0.18)	$ 0.72	$ (0.24)	$ (0.18)	$ 0.09
Weighted average number of shares used to compute net income (loss) per share (the year ended December 31, 2011 represents the period from May 16, 2011 to December 31, 2011)(2):					

Basic	382,610	379,195	376,819	371,847	368,474
Diluted	382,610	386,119	376,819	371,847	368,607

(1) Pursuant to the terms of our corporate reorganization that was completed simultaneously with the closing of the initial public offering, all of the interests in Kosmos Energy Holdings were exchanged for newly issued common shares of Kosmos Energy Ltd. based on these interests' relative rights as set forth in Kosmos Energy Holdings' then current operating agreement. This included convertible preferred units of Kosmos Energy Holdings which were redeemed upon the consummation of the qualified public offering (as defined in the operating agreement in effect prior to the initial public offering) into common shares of Kosmos Energy Ltd. based on the pre offering equity value of such interests.

(2) For the year ended December 31, 2011, we have presented net income (loss) per share attributable to common shareholders (including weighted average number of shares used to compute net income (loss) per share attributable to common shareholders) from the date of our corporate reorganization, May 16, 2011, to December 31, 2011. Net income for the period from May 16, 2011 through December 31, 2011 was $36.1 million.

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Consolidated Balance Sheets Information:

	December 31, 2015(1)(2) (In thousands)	2014(1)	2013(1)	2012(1)	2011(1)
Cash and cash equivalents	$ 275,004	$ 554,831	$ 598,108	$ 515,164	$ 673,092
Total current assets	734,148	1,010,476	734,961	750,118	1,112,481
Total property and equipment, net	2,322,839	1,784,846	1,522,962	1,525,762	1,377,041
Total other assets	146,063	131,537	53,742	48,021	7,565
Total assets	3,203,050	2,926,859	2,311,665	2,323,901	2,497,087
Total current liabilities	456,741	448,771	219,324	190,253	339,607
Total long-term liabilities	1,420,796	1,139,129	1,100,006	1,104,742	1,136,754
Total shareholders’ equity	1,325,513	1,338,959	992,335	1,028,906	1,020,726
Total liabilities and shareholders’ equity	3,203,050	2,926,859	2,311,665	2,323,901	2,497,087

(1) Effective December 31, 2015, the Company adopted new guidance on the presentation of debt issuance costs. This guidance was adopted retrospectively and all prior periods have been adjusted to reflect this change in accounting principle.

(2) Effective December 31, 2015, the Company adopted new guidance on the presentation of deferred taxes. The Company elected to adopt the accounting change using the prospective method. See Note 2 of Notes to the Consolidated Financial Statements.

Consolidated Statements of Cash Flows Information:

	December 31, 2015 (In thousands)	2014	2013	2012	2011
Net cash provided by (used in):					
Operating activities	$ 440,779	$ 443,586	$ 522,404	$ 371,530	$ 364,909
Investing activities	(800,240)	(347,679)	(324,133)	(402,662)	(385,140)
Financing activities	79,634	(139,184)	(115,327)	(126,796)	592,908

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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 leading independent oil and gas exploration and production company focused on frontier and emerging areas along the Atlantic Margin. Our assets include existing production and development projects offshore Ghana, large discoveries offshore Mauritania and Senegal, as well as exploration licenses with significant hydrocarbon potential offshore Portugal, Sao Tome and Principe, Suriname, Morocco and Western Sahara.

Recent Developments

Corporate

During April 2015, we issued an additional $225.0 million of 7.875% Senior Secured Notes due 2021 ("Senior 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.

In June 2015, we amended and restated the Corporate Revolver from a number of financial institutions, increasing the borrowing capacity from $300.0 million to $400.0 million, extending the maturity date to November 23, 2018 and lowering the commitment fees on the undrawn portion of the total commitments to 30% per annum of the respective margin. Additionally, a negative covenant was added that restricts our ability to incur additional indebtedness that would not be permitted by the indenture governing our 7.875% senior secured notes due 2021.

In July 2015, we reduced the size of our revolving letter of credit facility agreement ("LC facility") by $25.0 million to $75.0 million, 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.

Rig Agreement

In September 2015, Kosmos Energy Ventures ("KEV"), a subsidiary of Kosmos Energy Ltd., amended its Atwood Achiever rig agreement with Atwood Oceanics, Inc. effective October 1, 2015 to extend the contract end date by one year and reduce the rate to approximately $0.5 million per day. KEV is currently evaluating its option to revert to the original day rate of approximately $0.6 million per day and original agreement end date of November 2017. If KEV exercises the option, KEV would be required to make a rate recovery payment equal to the difference between the original day rate and the amended day rate multiplied by the number of days from the amendment effective date to the date the option is exercised plus certain administrative costs.

Ghana

In November 2015, we signed the Jubilee Field Unit Expansion Agreement with our partners to allow for the development of the Mahogany and Teak discoveries through the Jubilee FPSO and infrastructure, thus reducing their development costs. The expansion of the Jubilee Unit becomes effective upon approval by Ghana's Ministry of

Petroleum of the GJFFDP, which was submitted to the government of Ghana in December 2015. The GJFFDP encompasses future development of the Jubilee Field, in addition to future development of the Mahogany and Teak discoveries, which were declared commercial earlier in the year. We are currently in discussions with the government of Ghana concerning the GJFFDP. Upon approval of the GJFFDP by the Ministry of Petroleum, the Jubilee Unit will be

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expanded to include the Mahogany and Teak discoveries and revenues and expenses associated with these discoveries will be at the Jubilee Unit interests and the Mahogany and Teak areas will be excluded from any future Jubilee redeterminations.

We are currently in discussions with the government of Ghana regarding additional technical studies and evaluation that we want to conduct before we are able to make a determination regarding commerciality of the Akasa discovery. The WCTP Block partners have agreed they will take the steps necessary to transfer operatorship of the remaining portions of the WCTP Block to Tullow after approval of the GJFFDP by Ghana's Ministry of Petroleum.

In April 2015, the Special Chamber of the International Tribunal of the Law of the Sea (the "ITLOS") issued an order in response to the provisional measures sought by the Government of Cote d'Ivoire in its pending maritime boundary dispute with the Government of Ghana. ITLOS rejected the request that Ghana suspend all ongoing exploration and development operations in the disputed area in which the TEN development and Wawa Discovery are situated until ITLOS gives its decision on the maritime boundary dispute, which is expected by late 2017. ITLOS did order Ghana to suspend new drilling in the disputed area. On June 11, 2015, the Ghana Attorney General issued a letter to the DT Operator, which confirmed the DT Block partners may (i) continue to drill wells that had been started but not completed prior to the ITLOS order and (ii) carry out completion work on wells that have already been drilled. The TEN development is currently estimated to be approximately 80 percent complete. We expect TEN development activities will continue as planned with first oil expected in the third quarter of 2016. With respect to the Wawa Discovery, we plan to discuss with the Government of Ghana the effects of the ITLOS order on the proposed Wawa appraisal activities so that we can more clearly define our future plans and corresponding timeline. Under the terms of the petroleum contract, we currently have until May 2016 to make a decision regarding a declaration of commerciality if we are unable to extend the appraisal period.

Jubilee gas exports were temporarily halted in July due to an issue with the gas compression facilities on the Jubilee FPSO. The reduction in gas exports constrained Jubilee Field production to approximately 65,000 barrels (gross) of oil per day. The gas compression facilities were repaired and we resumed full production in early August 2015.

Mauritania

In March 2015, we closed a farm out agreement with Chevron covering the C8, C12 and C13 petroleum contracts offshore Mauritania. Under the terms of the farm out agreement, Chevron acquired a 30% non operated working interest in each of the contract areas. As partial consideration for the farm-out, Chevron paid a disproportionate share of the costs of one exploration well, the Marsouin-1 exploration well, as well as its proportionate share of certain previously incurred exploration costs. The final allocation resulted in sales proceeds of $28.7 million, which exceeded our book basis in the assets, resulting in a $24.7 million gain on the transaction. As a further component of the consideration for the farm-out, Chevron was required to make an election by February 1, 2016, to either farm-in to the Tortue-1 exploration well by paying a disproportionate share of the costs incurred in drilling of the well or, alternatively elect to not farm-in to the Tortue-1 exploration well and pay a disproportionate share of the costs of a second contingent exploration or appraisal well in the contract areas, subject to maximum expenditure caps. Chevron failed to make this mandatory election by the required date. Consequently, pursuant to the terms of the farm-out agreement, Chevron has withdrawn from our Mauritania blocks. Subsequently, Chevron requested that we engage in discussions related to the possible reinstatement of Chevron's interests in our Mauritania blocks and such discussions are ongoing. However, if no such agreement is reached in these discussions, Chevron's 30% non-operated participating interest will be reassigned to us (subject to requisite government approvals), and our participating interests in the Block C8, C12 and C13 petroleum contracts will be 90%.

In April 2015, we announced the Tortue-1 exploration well located in the Ahmeyim discovery area on Block C8 offshore Mauritania had made a significant, play-opening gas discovery. Based on preliminary analysis of drilling results and intermediate logging, the Tortue-1 exploration well has intersected approximately 117 meters (383 feet) of net hydrocarbon pay. A single gas pool was encountered in the Lower Cenomanian objective, which is comprised of three reservoirs totaling 88 meters (288 feet) in thickness over a gross hydrocarbon interval of 160 meters (528 feet). A fourth reservoir totaling 19 meters (62 feet) was penetrated within the Upper Cenomanian target over a gross hydrocarbon interval of 150 meters (492 feet). The exploration well also intersected an additional 10 meters (32 feet) of net hydrocarbon pay in the lower Albian section, which is interpreted to be gas. The well was drilled to a total depth of 5,107 meters. In January 2016, we drilled the Guembeul-1 well in our Saint Louis Profond block offshore Senegal, which confirmed the extension of the Ahmeyim discovery into Senegal. An appraisal program is currently being executed to delineate the Ahmeyim discovery. We are currently drilling the Ahmeyim-2 appraisal well in Mauritania to further delineate the Ahmeyim discovery.

In November 2015, we announced the Marsouin-1 exploration well, located in the northern part of Block C8 offshore Mauritania had made a second 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 5,153 meters in nearly 2,400 meters of water. Based on analysis of drilling results and logging data, Marsouin-1 encountered at least 70 meters (230 feet) of net gas pay in Upper and Lower Cenomanian intervals comprised of excellent quality reservoir sands. An appraisal program is currently being planned to delineate the Marsouin discovery.

Senegal

We obtained approximately 7,000 square kilometers of 3D seismic data over the central and eastern portions of the Cayar Offshore Profond and Saint Louis Offshore Profond blocks in January 2015. The results of the these 3D seismic programs provided sufficient encouragement to begin an acquiring additional 4,500 square kilometers of seismic data in November 2015 in the western portions of both blocks to fully evaluate the prospectivity. The survey is expected to be completed in February 2016.

In June 2015, we entered the first renewal of the exploration period for the Cayar Offshore Profond and Saint Louis Profond Contract Areas, which lasts for three years. The first renewal period includes a one well commitment in each block. After the required relinquishment of acreage to enter the first renewal, the Cayar Offshore Profond and Saint Louis Profond Contract Areas comprise approximately 1.4 million acres and 1.6 million acres, respectively.

In January 2016, we announced the Guembeul-1 exploration well, located in the northern part of the Saint Louis Offshore Profond license area in Senegal, has made a significant gas discovery. Located approximately five kilometers south of the Tortue-1 exploration well in Mauritania in approximately 2,700 meters of water, the Guembeul-1 exploration well was drilled to a total depth of 5,245 meters. The well encountered 101 meters (331 feet) of net gas pay in two excellent quality reservoirs, including 56 meters (184 feet) in the Lower Cenomanian and 45 meters (148 feet) in the underlying Albian, with no water encountered. Importantly, the Guembeul-1 exploration well has demonstrated reservoir continuity as well as static pressure communication with the Tortue-1 exploration well in the Lower Cenomanian.

Western Sahara

Drilling of the CB-1 exploration well on the Cap Boujdour Offshore block was completed in March 2015. The well penetrated approximately 14 meters of net gas and condensate pay in clastic reservoirs over a gross hydrocarbon bearing interval of approximately 500 meters. The discovery is sub-commercial, and the well was plugged and abandoned. However, the well demonstrated a working petroleum system including the presence of a hydrocarbon charge. The results will be integrated with the ongoing geological evaluation to determine future exploration activity. Total well and other related costs of $86.8 million are included in exploration expenses in the accompanying consolidated statement of operations for the year ended December 31, 2015.

Portugal

In March 2015, we closed a farm-in agreement with Repsol Exploracion, S.A. ("Repsol"), to acquire a non-operated interest in the Camarao, Ameijoa, Mexilhao and Ostra blocks in the Peniche Basin offshore Portugal. As part of the farm-in agreement, we reimbursed a portion of Repsol's previously incurred exploration costs, as well as partially carried Repsol's share of the costs of a planned 3D seismic program. After giving effect to the farm-in agreement, our participating interest is 31% in each of the blocks.

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In September 2015, we completed a 3D seismic survey of approximately 3,200 square kilometers over the Camarao block offshore Portugal.

Sao Tome and Principe

In October 2015, we closed a sale and purchase agreement with ERHC Energy EEZ, LDA, whereby we acquired an 85% participating interest and operatorship in Block 11 offshore Sao Tome and Principe. The national petroleum agency, Agencia Nacional Do Petroleo De Sao Tome E Principe (“ANP”), has a 15% carried interest.

In November 2015, we closed a farm-in agreement with Galp Energia Sao Tome E Principe, Unipessoal, LDA (“Galp”), a wholly owned subsidiary of Petrogal, S.A. to acquire a 45% non-operated participating interest in Block 6 offshore Sao Tome and Principe.

In January 2016, we closed a farm-in agreement with Equator, an affiliate of Oando, for Block 5 offshore Sao Tome and Principe, whereby we acquired a 65% participating interest and operatorship in the block. Certain governmental approvals and processes are still required to be completed before this acquisition is effective.

Suriname

In April 2015, we received an extension of the initial exploration phase for Block 45 offshore Suriname which now expires in September 2016. In December 2015, we received an extension of the initial exploration phase for Block 42 offshore Suriname which now expires in September 2018.

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Results of Operations

All of our results, as presented in the table below, represent operations from the Jubilee Field in Ghana. Certain operating results and statistics for the years ended December 31, 2015, 2014 and 2013 are included in the following table:

	Years Ended December 31,		
	2015	2014	2013
	(In thousands, except per barrel data)		
Sales volumes:			
MBbl	8,538	8,728	7,778
Revenues:			
Oil sales	$ 446,696	$ 855,877	$ 851,212
Average sales price per Bbl	52.32	98.06	109.44
Costs:			
Oil production, excluding workovers	$ 92,994	$ 79,648	57,608
Oil production, workovers	12,342	20,474	39,183
Total oil production costs	$ 105,336	$ 100,122	$ 96,791
Depletion and depreciation	$ 155,966	$ 198,080	$ 222,544
Average cost per Bbl:			
Oil production, excluding workovers	$ 10.89	$ 9.13	$ 7.41
Oil production, workovers	1.45	2.35	5.04
Total oil production costs	12.34	11.48	12.45
Depletion and depreciation	18.27	22.69	28.61
Oil production cost and depletion costs	$ 30.61	$ 34.17	$ 41.06

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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, 2015 vs. 2014

	Years Ended December 31, 2015	2014	Increase (Decrease)
	(In thousands)		
Revenues and other income:			
Oil and gas revenue	$ 446,696	$ 855,877	$ (409,181)
Gain on sale of assets	24,651	23,769	882
Other income	209	3,092	(2,883)
Total revenues and other income	471,556	882,738	(411,182)
Costs and expenses:			
Oil and gas production	105,336	100,122	5,214
Exploration expenses	156,203	93,519	62,684
General and administrative	136,809	135,231	1,578
Depletion and depreciation	155,966	198,080	(42,114)
Interest and other financing costs, net	37,209	45,548	(8,339)
Derivatives, net	(210,649)	(281,853)	71,204
Restructuring charges	—	11,742	(11,742)
Other expenses, net	5,246	2,081	3,165
Total costs and expenses	386,120	304,470	81,650
Income before income taxes	85,436	578,268	(492,832)
Income tax expense	155,272	298,898	(143,626)
Net income (loss)	$ (69,836)	$ 279,370	$ (349,206)

Oil and gas revenue. Oil and gas revenue decreased by $409.2 million during the year ended December 31, 2015 as compared to the year ended December 31, 2014, as a result of a lower realized price per barrel and a slight decrease in sales volumes. We lifted and sold 8,538 MBbl at an average realized price per barrel of $52.32 in 2015 and 8,728 MBbl at an average realized price per barrel of $98.06 in 2014.

Oil and gas production. Oil and gas production costs increased by $5.2 million during the year ended December 31, 2015 as compared to the year ended December 31, 2014 primarily as a result of an increase in routine operating expenses, including $2.8 million related to repairs to the gas compressor and costs to remove the damaged water injection riser, partially mitigated by a reduction in well workover costs. Our workover costs are related to performing workovers on our wells, which are performed on an as needed basis. We expect the amount of costs associated with workovers to fluctuate based on the activity level during each year.

Exploration expenses. Exploration expenses increased by $62.7 million during the year ended December 31, 2015, as compared to the year ended December 31, 2014. The increase is primarily a result of $86.8 million of unsuccessful well costs for the Western Sahara CB-1 exploration well in 2015 partially mitigated by a decrease in seismic costs of $28.6 million.

Depletion and depreciation. Depletion and depreciation decreased $42.1 million during the year ended December 31, 2015, as compared with the year ended December 31, 2014, primarily as a result of a lower depletion rate in 2015 as a result of an increase in our proved reserves associated with the Jubilee Field.

Interest and other financing costs, net. Interest expense decreased by $8.3 million during the year ended December 31, 2015, as compared to the year ended December 31, 2014, primarily as a result of higher gross interest costs driven by a larger debt balance offset by higher capitalized interest during the year ended December 31, 2015, as compared to the year ended December 31, 2014.

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Derivatives, net. During the years ended December 31, 2015 and 2014, we recorded a gain of $210.6 million and $281.9 million, respectively, on our outstanding hedge positions. The gains recorded were a result of decreases in the forward oil price curve during the respective periods.

Restructuring charges. During the year ended December 31, 2015, we had no restructuring charges; however, during the year ended December 31, 2014, we recognized $11.7 million in restructuring charges for employee severance and related benefit costs incurred as part of a corporate reorganization, which includes $5.0 million of non cash expense related to awards granted under our LTIP.

Income tax expense. The Company's effective tax rates for the years ended December 31, 2015 and 2014 were 182% and 52%, respectively. The effective tax rates for the periods presented were impacted by losses, primarily related to exploration expenses, incurred in jurisdictions in which we are not subject to taxes and losses incurred in jurisdictions in which we have valuation allowances against our deferred tax assets and therefore we do not realize any tax benefit on such expenses or losses. Income tax expense decreased by $143.6 million during the year ended December 31, 2015, as compared with the year ended December 31, 2014, primarily as a result of lower revenue in Ghana.

Year Ended December 31, 2014 vs. 2013

	Years Ended December 31, 2014	2013	Increase (Decrease)
	(In thousands)		
Revenues and other income:			
Oil and gas revenue	$ 855,877	$ 851,212	$ 4,665
Gain on sale of assets	23,769	—	23,769
Other income	3,092	941	2,151
Total revenues and other income	882,738	852,153	30,585
Costs and expenses:			
Oil and gas production	100,122	96,791	3,331
Exploration expenses	93,519	230,314	(136,795)
General and administrative	135,231	158,421	(23,190)
Depletion and depreciation	198,080	222,544	(24,464)
Interest and other financing costs, net	45,548	47,590	(2,042)
Derivatives, net	(281,853)	17,027	(298,880)
Restructuring charges	11,742	—	11,742
Other expenses, net	2,081	3,512	(1,431)
Total costs and expenses	304,470	776,199	(471,729)
Income before income taxes	578,268	75,954	502,314
Income tax expense	298,898	166,998	131,900
Net income (loss)	$ 279,370	$ (91,044)	$ 370,414

Oil and gas revenue. Oil and gas revenue increased by $4.7 million during the year ended December 31, 2014 as compared to the year ended December 31, 2013, primarily as a result of an increase in sales volumes, nine liftings in 2014 compared to eight in 2013 partially offset by a lower realized price per barrel. We lifted and sold 8,728 MBbl at an average realized price per barrel of $98.06 in 2014 and 7,778 MBbl at an average realized price per barrel of $109.44 in 2013.

Gain on sale of assets. During the year ended December 31, 2014, we closed three farm out agreements with BP. As part of the transaction, we received proceeds in excess of our book basis, resulting in a gain of $23.8 million.

Oil and gas production. Oil and gas production costs increased by $3.3 million during the year ended December 31, 2014 as compared to the year ended December 31, 2013 primarily as a result of an increase in routine operating expenses offset by a reduction in well workover costs and non routine operating costs. Our workover costs are

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related to performing workovers on our wells, which are performed on an as needed basis. We expect the amount of costs associated with workovers to fluctuate based on the activity level during each year.

Exploration expenses. Exploration expenses decreased by $136.8 million during the year ended December 31, 2014, as compared to the year ended December 31, 2013. The decrease is primarily a result of $105.8 million of unsuccessful well and other related costs primarily related to the Cameroon Sipo 1 exploration well, the Ghana Sapele 1 exploration well and the Ghana Akasa 2A appraisal well and $110.4 million for seismic costs primarily for Mauritania, Ireland, Morocco and new business activities incurred during the year ended December 31, 2013 compared to $81.2 million for seismic costs for Senegal, Morocco (including Western Sahara), Mauritania, Ireland, Suriname and new business during the year ended December 31, 2014.

General and administrative. General and administrative costs decreased by $23.2 million during the year ended December 31, 2014, as compared to the year ended December 31, 2013. The decrease from prior year is related to an increase in capitalized general and administrative costs and general and administrative costs incurred for the benefit of and allocated to exploration expense; and a decrease in professional fees and occupancy and general expenses partially offset by an increase in compensation and benefits.

Depletion and depreciation. Depletion and depreciation decreased $24.5 million during the year ended December 31, 2014, as compared with the year ended December 31, 2013, primarily as a result of a lower depletion rate in 2014 as a result of an increase in our proved reserves associated with the Jubilee Field.

Interest and other financing costs, net. Interest expense decreased by $2.0 million during the year ended December 31, 2014, as compared to the year ended December 31, 2013, primarily as a result of a write down of the deferred interest (reduction in interest expense) as a result of refinancing our commercial debt facility effective in March 2014 and a lower average outstanding debt balance during the year ended December 31, 2014, as compared to the year ended December 31, 2013.

Derivatives, net. During the years ended December 31, 2014 and 2013, we recorded a gain of $281.9 million and a loss of $17.0 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.

Restructuring charges. During the year ended December 31, 2014, we recognized $11.7 million in restructuring charges for employee severance and related benefit costs incurred as part of a corporate reorganization, which includes $5.0 million of non cash expense related to awards granted under our LTIP.

Income tax expense. The Company’s effective tax rates for the years ended December 31, 2014 and 2013 were 51.7% and 219.9%, respectively. The effective tax rates for the periods presented are impacted by losses, primarily related to exploration expenses, incurred in jurisdictions in which we are not subject to taxes and, therefore, do not generate any income tax benefits and losses incurred in jurisdictions in which we have valuation allowances against our deferred tax assets and therefore we do not realize any tax benefit on such losses. Income tax expense increased $131.9 million during the years ended December 31, 2014, as compared with December 31, 2013, primarily as a result of deferred taxes related to the significant mark to market gain on derivatives.

Liquidity and Capital Resources

We are actively engaged in an ongoing process of anticipating and meeting our funding requirements related to exploring for and developing oil and natural gas resources along the Atlantic Margin. 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. In relation to cash flow generated from our operating activities, if we are unable to continuously export associated natural gas in large quantities from the Jubilee Field, and the potential production restraints caused thereby, then the Company’s cash flows from operations will be adversely affected. In prior years, certain near wellbore productivity issues were identified, impacting several Phase 1 production wells. We have also experienced mechanical issues in the Jubilee Field, including failures of our water injection facilities and gas compressor on the FPSO. This equipment downtime negatively impacted past oil production. The Jubilee Unit partners identified a

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means of successfully mitigating the near wellbore productivity issues with ongoing acid stimulation treatments and we are in the process of correcting the current mechanical issues experienced in the Jubilee Field.

Following a February 2016 inspection of the turret area of the FPSO, by SOFEC, Inc. ("SOFEC"), the original turret manufacturer, a potential issue was identified with the turret bearing. As a precautionary measure, additional operating procedures to monitor the turret bearing and reduce the degree of rotation of the vessel are being put in place.

SOFEC will now undertake further offshore examinations and Tullow, operator of the Jubilee Unit, will work with SOFEC to determine what further measures will be required. Oil production and gas export is continuing as normal.

While we are presently in a strong financial position, the decline in oil prices experienced since 2014, if prolonged or if further deterioration of pricing continues, could negatively impact our ability to generate sufficient operating cash flows to meet our funding requirements as well as impact the borrowing base available under the Facility or the related debt covenants. Commodity prices are volatile and future prices cannot be accurately predicted. We maintain a hedging program to partially mitigate the price volatility. Our investment decisions are based on longer term commodity prices based on the long term nature of our projects and development plans. Current commodity prices, our hedging program and our current liquidity position support our capital program for 2016. As such, our 2016 capital budget is based on our development plans for Ghana and our exploration and appraisal program for 2016.

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, 2015, 2014 and 2013

	Years Ended December 31,		
	2015	2014	2013
	(In thousands)		
Sources of cash and cash equivalents:			
Net cash provided by operating activities	$ 440,779	$ 443,586	$ 522,404
Net proceeds from issuance of senior secured notes	206,774	294,000	—
Borrowings under long-term debt	100,000	—	—
Proceeds on sale of assets	28,692	58,315	—
Restricted cash	—	20,924	—
	776,245	816,825	522,404
Uses of cash and cash equivalents:			
Oil and gas assets	$ 823,642	$ 424,535	$ 317,413
Other property	1,483	2,383	4,970
Payments on long-term debt	200,000	400,000	100,000
Purchase of treasury stock	18,110	11,096	13,101
Deferred financing costs	9,030	22,088	2,226
Restricted cash	3,807	—	1,750
	1,056,072	860,102	439,460
Increase (decrease) in cash and cash equivalents	$ (279,827)	$ (43,277)	$ 82,944

Net cash provided by operating activities. Net cash provided by operating activities in 2015 was $440.8 million compared with net cash provided by operating activities of $443.6 million in 2014 and $522.4 million in 2013, respectively. The decrease in cash provided by operating activities in the year ended December 31, 2015 when compared to the same period in 2014 was primarily as a result of a decrease in results from operations driven by lower realized revenue per barrel sold mitigated by a positive change in working capital items. The increase in cash provided by operating activities in 2014 when compared to 2013 was primarily as a result of an increase in oil and gas revenues offset by a negative change in working capital items.

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The following table presents our liquidity and financial position as of December 31, 2015:

	December 31, 2015 (In thousands)
Cash and cash equivalents	$ 275,004
Restricted cash	35,858
Senior Notes at par	525,000
Drawings under the Facility	400,000
Net debt	$ 614,138
Availability under the Facility	$ 1,100,000
Availability under the Corporate Revolver	$ 400,000
Available borrowings plus cash and cash equivalents	$ 1,775,004

Capital Expenditures and Investments

We expect to incur capital costs as we:

- complete the TEN development and fund asset integrity projects at Jubilee;
- execute exploration and appraisal activities in our Senegal and Mauritania license areas; and
- purchase and analyze seismic, perform new ventures and manage our rig activities.

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 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, our ability to utilize our available drilling rig capacity, the availability of suitable equipment and qualified personnel and our cash flows from operations. 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.

2016 Capital Program

We estimate we will spend approximately $650 million of capital for the year ending December 31, 2016. This capital expenditure budget consists of:

- approximately $200 million for developmental related expenditures offshore Ghana focused on the delivery of the TEN project and Jubilee asset integrity;
- approximately $250 million in Mauritania and Senegal related to the appraisal of the Ahmeyim discovery, drilling of one oil prospect in Senegal and the acquisition of additional seismic; and
- approximately $200 million related to seismic acquisition, new ventures and rig costs for the Atwood Achiever.

This positions us to achieve our objectives and invest counter-cyclically while maintaining a strong balance sheet. The ultimate amount of capital we will spend may fluctuate materially based on market conditions and the success

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of our drilling results. Given the current environment and status of ongoing prospect development, we plan to suspend drilling activities after we complete the drilling of the Ahmeyim-2 appraisal well and one oil prospect in Senegal. 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 exploration and appraisal drilling program, 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 exploration, appraisal and development of our oil and natural gas assets.

Significant Sources of Capital

Facility

In March 2014, the Company amended and restated the Facility with a total commitment of $1.5 billion from a number of financial institutions. The Facility supports our oil and gas exploration, appraisal and development programs and corporate activities.

As part of the debt refinancing in March 2014, 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 existing unamortized debt issuance costs attributable to those participants were expensed. As a result, we recorded a $2.9 million loss on the extinguishment of debt for the year ended December 31, 2014. As of December 31, 2015, we have $37.5 million of unamortized issuance costs related to the Facility, which will be amortized over the remaining term of the Facility, including certain costs related to the amendment.

As of December 31, 2015, borrowings under the Facility totaled $400.0 million and the undrawn availability under the Facility was $1.1 billion.

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); LIBOR; and mandatory cost (if any, as defined in the Facility). 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 40% 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. As part of the March 2014 amendment, the Facility's estimated effective interest rate was changed and, accordingly, we adjusted our estimate of deferred interest previously recorded during prior years by $4.5 million, which was recorded as a reduction to interest expense for the year ended December 31, 2014.

The Facility provides a revolving credit and letter of credit facility. The availability period for the revolving credit facility, as amended in March 2014 expires on March 31, 2018; however the Facility has a revolving credit sublimit, which will be the lesser of $500.0 million and the total available facility at that time, that will be available for drawing until the date falling one month prior to the final maturity date. The letter of credit sublimit expires on the final maturity date. The available facility amount is subject to borrowing base constraints and, beginning on March 31, 2018, outstanding borrowings will be constrained by an amortization schedule. The Facility has a final maturity date of March 31, 2021. As of December 31, 2015, we had no letters of credit issued under the Facility.

We have the right to cancel all the undrawn commitments under the 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 and

September 30. 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.

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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, 2015 (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 November 2012, we secured a Corporate Revolver from a number of financial institutions which, as amended in June 2015, has an availability of $400.0 million. The Corporate Revolver is available for all subsidiaries for general corporate purposes and for oil and gas exploration, appraisal and development programs.

As of December 31, 2015, 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 (6.0%), 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, as amended in June 2015, for the lenders are equal to 30% per annum of the respective margin when a commitment is available for utilization.

The Corporate Revolver, as amended in June 2015, expires on November 23, 2018. 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, 2015 (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

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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 is $75.0 million, as amended in July 2015, with additional commitments up to $50.0 million being available if the existing lender increases its commitments or if commitments from new financial institutions are 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%. The fees associated with outstanding letters of credit issued will be 0.5% per annum. The LC Facility has an availability period which expires on June 1, 2016. We may voluntarily cancel any commitments available under the LC Facility at any time. As of December 31, 2015, there were nine letters of credit totaling $15.3 million under the LC Facility. The LC Facility contains customary cross default provisions.

7.875% Senior Secured Notes due 2021

During August 2014, the Company issued $300.0 million of Senior 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 Senior 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 Notes have identical terms to the initial $300.0 million Senior Notes, other than the date of issue, the initial price, the first interest payment date and the first date from which interest accrued.

The Senior Notes mature on August 1, 2021. Interest is payable semi annually in arrears each February 1 and August 1 commencing on February 1, 2015 for the initial $300.0 million Senior Notes and August 1, 2015 for the additional $225.0 million Senior Notes. The Senior Notes are secured (subject to certain exceptions and permitted liens) by a first ranking fixed equitable charge on all shares held by us in our direct subsidiary, Kosmos Energy Holdings. The Senior Notes are currently guaranteed on a subordinated, unsecured basis by our existing restricted subsidiaries that guarantee the Facility and the Corporate Revolver, and, in certain circumstances, the Senior Notes will become guaranteed by certain of our other existing or future restricted subsidiaries (the "Guarantees").

Redemption and Repurchase. At any time prior to August 1, 2017 and subject to certain conditions, the Company may, on any one or more occasions, redeem up to 35% of the aggregate principal amount of Senior Notes issued under the indenture dated August 1, 2014 related to the Senior Notes (the "Indenture") at a redemption price of 107.875%, plus accrued and unpaid interest, with the cash proceeds of certain eligible equity offerings. Additionally, at any time prior to August 1, 2017, 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 a make whole premium. On or after August 1, 2017, 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 August 1, 2017, but before August 1, 2018	103.9	%
On or after August 1, 2018, but before August 1, 2019	102.0	%
On or after August 1, 2019 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

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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 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 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.

Covenants. The 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.

Collateral. The Senior Notes are secured (subject to certain exceptions and permitted liens) by a first ranking fixed equitable charge on all currently outstanding shares, additional shares, dividends or other distributions paid in respect of such shares or any other property derived from such shares, in each case held by us in relation to the Company's direct subsidiary, Kosmos Energy Holdings, pursuant to the terms of the Charge over Shares of Kosmos Energy Holdings dated November 23, 2012, as amended and restated on March 14, 2014, between the Company and BNP Paribas as Security and Intercreditor Agent. The Senior Notes share pari passu in the benefit of such equitable charge based on the respective amounts of the obligations under the Indenture and the amount of obligations under the Corporate Revolver. The Guarantees are not secured.

Contractual Obligations

The following table summarizes by period the payments due for our estimated contractual obligations as of December 31, 2015:

	Payments Due By Year(5)						
	Total	2016	2017	2018	2019	2020	Thereafter
	(In thousands)						
Principal debt repayments(1)	$ 925,000	$ —	$ —	$ —	$ —	$ 185,714	$ 739,286
Interest payments on long-term debt(2)	409,052	78,838	80,731	73,824	65,740	64,962	44,957
Operating leases(3)	12,970	3,230	3,286	3,323	3,131	—	—
Atwood Achiever drilling rig contract(4)	518,862	181,379	180,883	156,600	—	—	—

(1) Includes the scheduled principal maturities for the $525.0 million aggregate principal amount of Senior Notes issued in August 2014 and April 2015 and the Facility. The scheduled maturities of debt related to the Facility are based on the level of borrowings and the estimated future available borrowing base as of December 31, 2015. 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. As of December 31, 2015, there were no borrowings under the Corporate Revolver.

(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.

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(4) Commitments calculated using the amended day rate of $0.5 million effective October 1, 2015, excluding applicable taxes. KEV is currently evaluating its option to revert to the original day rate of approximately $0.6 million per day and original agreement end date of November 2017. If KEV exercises the option, KEV would be required to make a rate recovery payment equal to the difference between the original day rate and the amended day rate multiplied by the number of days from the amendment effective date to the date the option is exercised plus certain administrative costs.
(5) 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.

We currently have a commitment to drill one exploration well in Morocco and Senegal. In Morocco, our partner is obligated to fund our share of the cost of the exploration well, subject to a maximum spend of $120.0 million. Additionally, we have 3D seismic requirements in Sao Tome and Morocco of 2,750 square kilometers and 1,200 square kilometers, respectively.

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,						Liability Fair Value at December 31,
	2016	2017	2018	2019	2020	Thereafter	2015
	(In thousands, except percentages)						
Fixed rate debt:							
Senior Notes	$ —	$ —	$ —	$ —	$ —	$ 525,000	$ (423,612)
Fixed interest rate	7.88 %	7.88 %	7.88 %	7.88 %	7.88 %	7.88 %	
Variable rate debt:							
Facility(1)	$ —	$ —	$ —	$ —	$ 185,714	$ 214,286	$ (400,000)
Weighted average interest rate(2)	3.98 %	4.59 %	5.41 %	5.72 %	6.50 %	6.74 %	
Interest rate swaps:							
Notional debt amount(3)	$ 12,500	$ —	$ —	$ —	$ —	$ —	$ (90)
Average fixed rate payable	2.27 %	—	—	—	—	—	
Variable rate receivable(4)	0.83 %	—	—	—	—	—	
Capped interest rate							

swaps:												
Notional debt amount	$	200,000	$	200,000	$	200,000	$	—	$	—	$	—	$ (406)
Cap		3.00 %		3.00 %		3.00 %		—		—		—	
Average fixed rate payable(5)		1.23 %		1.23 %		1.23 %		—		—		—	
Variable rate receivable(4)		0.69 %		1.27 %		1.70 %		—		—		—	

(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, 2015. 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. As of December 31, 2015, there were no borrowings under the Corporate Revolver.

(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.

(3) Represents weighted average notional contract amounts of interest rate derivatives. In the final year of maturity, represents notional amount from January - June.

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(4) Based on implied forward rates in the yield curve at the reporting date.
(5) We expect to pay the fixed rate if 1-month LIBOR is below the cap, and pay the market rate less the spread between the cap and the fixed rate if LIBOR is above the cap, net of the capped interest rate swaps.

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, 2015, our material off balance sheet arrangements and transactions include 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 use the sales method of accounting for oil and gas revenues. Under this method, we recognize revenues on the volumes sold based on the provisional sales prices. 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, 2015 and 2014, we had no oil and gas imbalances recorded in our consolidated financial statements.

Our oil and gas 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 for accounting purposes, 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 occurs.

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 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.

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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 tax rate changes, 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, 2015 and 2014, 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 turnaround 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 three way collars, put options, call options and swaps. We also use 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. Effective June 1, 2010, we discontinued hedge accounting on our interest rate swap contracts and accordingly the changes in the fair value of the instruments are recognized in earnings in the period of change. The effective portions of the discontinued hedges as of May 31, 2010, were included in accumulated other comprehensive income or loss ("AOCI") in the equity section of the accompanying consolidated balance sheets, and were transferred to earnings when the hedged transactions settled.

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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 and depreciation 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. 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

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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.

New Accounting Pronouncements

In February 2015, the FASB issued ASU 2015-02, “Consolidation (Topic 810) - Amendments to the Consolidation Analysis.” ASU 2015-02 modifies existing consolidation guidance related to limited partnerships and similar legal entities, eliminates the presumption that a general partner should consolidate a limited partnership, affects the consolidation analysis of reporting entities that are involved with Variable Interest Entities, particularly those that have fee arrangements and related party relationships, and provides a scope exception from consolidation guidance for reporting entities with interests in legal entities that are required to comply with or operate in accordance with requirements that are similar to those in Rule 2a-7 of the Investment Company Act of 1940 for registered money market funds. This guidance is effective for public companies for fiscal years beginning after December 15, 2015 with early adoption permitted. The adoption of this standard is not expected to have a material impact on the Company’s consolidated financial statements.

In April 2015, the FASB issued ASU 2015-03, “Interest - Imputation of Interest (Subtopic 835-30) – Simplifying the Presentation of Debt Issuance Costs.” ASU 2015-03 modifies existing guidance related to the presentation of debt issuance costs which are currently capitalized and presented on the balance sheet as an asset. ASU 2015-03 requires these costs to be presented as a direct deduction from the face amount of the related debt. In August 2015, the FASB issued ASU 2015-15, “Interest – Imputation of Interest (Subtopic 835-30) — Presentation and Subsequent Measurement of Debt Issuance Costs Associated with the Line-of-Credit Arrangements.” ASU 2015-15 clarifies the guidance regarding line-of-credit arrangements with regards to the recently issued ASU 2015-03 to incorporate statements made by the SEC Staff during their June 18, 2015 Emerging Issues Task Force meeting. The SEC Staff has clarified they would not object to an entity deferring and presenting debt issue costs as an asset and subsequently amortizing the deferred debt issue costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of credit arrangement. This guidance is effective for public companies for fiscal years beginning after December 15, 2015 with early adoption permitted. The Company early adopted ASU 2015-03 and ASU 2015-15 as of December 31, 2015 and applied retrospectively for all periods presented. The adoption of this standard resulted in $39.3 million and $45.9 million of net deferred financing costs as of December 31, 2015 and 2014, respectively, being reclassified as a direct reduction of long-term debt on the balance sheet.

In July 2015, the FASB issued ASU 2015-11, “Inventory (Topic 330) — Simplifying the Measurement of Inventory.” ASU 2015-11 changes the measurement principle for entities that do not measure inventory using the last-in, first-out (LIFO) or retail inventory method from the lower of cost or market to lower of cost and net realizable value. The ASU also eliminates the requirement for these entities to consider replacement cost or net realizable value less an approximately normal profit margin when measuring inventory. The ASU is effective for annual periods beginning after December 15, 2016, and interim periods within those annual periods. The adoption of this standard is not expected to have a material impact on the Company’s consolidated financial statements.

In August 2015, the FASB issued ASU 2015-14, “Revenue from Contracts with Customers (Topic 606) — Deferral of the Effective Date.” ASU 2015-14 defers the effective date of ASU 2014-09 by one year to annual reporting periods beginning after December 15, 2017 with early adoption permitted for periods beginning after December 15, 2016. The adoption of this standard is not expected to have a material impact on the Company’s consolidated financial statements.

In November 2015, the FASB issued ASU 2015-17, “Income Taxes (Topic 740) — Balance Sheet Classification of Deferred Taxes.” ASU 2015-17 eliminates the requirement to classify deferred tax assets and liabilities as current or long-term based on how the related assets or liabilities are classified. All deferred taxes are now required to be classified as long-term including any associated valuation allowances. This guidance is effective for public companies for fiscal years beginning after December 15, 2016 with early adoption permitted on either a prospective or retrospective basis. The Company has early adopted this guidance as of December 31, 2015 on a prospective basis and prior periods presented have not been retrospectively adjusted.

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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 Information 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, 2015:

	Derivative Contracts Assets (Liabilities)		
	Commodities	Interest Rates	Total
	(In thousands)		
Fair value of contracts outstanding as of December 31, 2014	$ 252,485	$ (789)	$ 251,696
Changes in contract fair value	210,652	(462)	210,190
Contract maturities	(225,496)	755	(224,741)
Fair value of contracts outstanding as of December 31, 2015	$ 237,641	$ (496)	$ 237,145

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. Our oil sales are indexed against Dated Brent crude. Oil prices in 2015 ranged between $35.64 and $66.65 during the year. In June 2014, Dated Brent crude peaked above $115 per barrel and as recently as January 2016, had fallen below $30 per barrel.

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 three way 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.

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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, 2015:

Term	Type of Contract	MBbl	Weighted Average Dated Brent Price per Bbl Deferred Premium Payable	Swap	Put	Floor	Ceiling	Call	Asset (Liability) Fair Value at December 31, 2015(1)
2016:									
January — December	Purchased puts	2,000	$ 3.41	$ —	$ —	$ 85.00	$ —	$ —	$ 81,335
January — December	Three-way collars	2,000	—	—	—	85.00	110.00	135.00	88,074
January — December	Swaps with puts	2,000	—	75.00	60.00	—	—	—	28,595
2017:									
January — December	Swap with puts/calls	2,000	$ 2.13	$ 72.50	$ 55.00	$ —	$ —	$ 90.00	$ 23,157
January — December	Swap with puts	2,000	—	64.95	50.00	—	—	—	17,988
January — December	Sold calls(2)	2,000	—	—	—	—	85.00	—	(1,176)
2018 :									
January — December	Three-way collars	913	$ 2.37	$ —	$ 45.00	$ 60.00	$ 75.00	$ —	$ 2,688
2019 :									
January — December	Sold calls(2)	913	$ —	$ —	$ —	$ —	$ 80.00	$ —	$ (3,020)

(1) Fair values are based on the average forward Dated Brent oil prices on December 31, 2015 which by year are: 2016—$40.85, 2017—$47.70, 2018—$51.88 and 2019—$53.27. These fair values are subject to changes in the underlying commodity price. The average forward Dated Brent oil prices based on February 16, 2016 market quotes by year are: 2016—$34.56 2017—$40.57 2018—$44.25 and 2019—$45.65.

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

In February 2016, we entered into three-way collar contracts for 2.0 MMBbl from January 2017 through December 2017 with a floor price of $45.00 per barrel, a ceiling price of $60 per barrel and a sold put price of $30.00 per barrel. In addition, we sold call contracts for 2.0 MMBbl from January 2018 through December 2018 with a strike price of $65.00 per barrel. The contracts are indexed to Dated Brent prices and have a weighted average deferred premium payable of $1.68 per barrel.

At December 31, 2015, our open commodity derivative instruments were in a net asset position of $237.6 million. As of December 31, 2015, a hypothetical 10% price increase in the commodity futures price curves would decrease future pre tax earnings by approximately $32.0 million. Similarly, a hypothetical 10% price decrease would increase future pre tax earnings by approximately $27.5 million.

Interest Rate Derivative Instruments

See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Contractual Obligations” for specific information regarding the terms of our interest rate derivative instruments that are sensitive to changes in interest rates.

Interest Rate Sensitivity

At December 31, 2015, we had floating rate indebtedness outstanding under the Facility of $400.0 million, of which $187.5 million bore interest at floating rates after consideration of our fixed rate interest rate hedges. The interest rate on this indebtedness as of December 31, 2015 was approximately 3.7%. If LIBOR increased 10% at this level of floating rate debt, we would pay an additional $0.1 million in interest expense per year on the Facility. We paid commitment fees on the $1.1 billion of undrawn availability under the Facility and on the $400.0 million of undrawn availability under the Corporate Revolver during 2015, which are not subject to changes in interest rates.

As of December 31, 2015, the fair market value of our interest rate swaps was a net liability of approximately

$0.5 million. If LIBOR increased by 10%, we estimate it would have a negligible impact on the fair market value of our interest rate swaps.

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders

Kosmos Energy Ltd.

We have audited the accompanying consolidated balance sheets of Kosmos Energy Ltd. as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income (loss), shareholders' equity and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedules included at Item 15(a). These financial statements and schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Kosmos Energy Ltd. at December 31, 2015 and 2014, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly, in all material respects, the financial information set forth therein.

As discussed in Note 2 to the consolidated financial statements, Kosmos Energy Ltd. adopted FASB ASU 2015-03, Simplifying the Presentation of Debt Issuance Costs and FASB ASU 2015-17, Balance Sheet Classification of Deferred Taxes.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Kosmos Energy Ltd.'s internal control over financial reporting as of December 31, 2015, 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 22, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Dallas, Texas

February 22, 2016

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders

Kosmos Energy Ltd.

We have audited Kosmos Energy Ltd.'s internal control over financial reporting as of December 31, 2015, 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). Kosmos Energy Ltd.'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 conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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.

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.

In our opinion, Kosmos Energy Ltd. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Kosmos Energy Ltd. as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income (loss), shareholders' equity and cash flows for each of the three years in the period ended December 31, 2015 of Kosmos Energy Ltd. and our report dated February 22, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Dallas, Texas

February 22, 2016

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KOSMOS ENERGY LTD.

CONSOLIDATED BALANCE SHEETS

(In thousands, except share data)

	December 31, 2015	2014
Assets		
Current assets:		
Cash and cash equivalents	$ 275,004	$ 554,831
Restricted cash	28,533	15,926
Receivables:		
Joint interest billings	67,200	60,592
Oil sales	35,950	61,731
Other	34,882	41,221
Inventories	85,173	55,354
Prepaid expenses and other	24,766	25,278
Deferred tax assets	—	32,268
Derivatives	182,640	163,275
Total current assets	734,148	1,010,476
Property and equipment:		
Oil and gas properties, net	2,314,226	1,773,186
Other property, net	8,613	11,660
Property and equipment, net	2,322,839	1,784,846
Other assets:		
Restricted cash	7,325	16,125
Long-term receivables - joint interest billings	37,687	14,174
Deferred financing costs, net of accumulated amortization of $8,475 and $6,404 at December 31, 2015 and December 31, 2014, respectively	7,986	2,846
Long-term deferred tax assets	33,209	9,182
Derivatives	59,856	89,210
Total assets	$ 3,203,050	$ 2,926,859
Liabilities and shareholders’ equity		
Current liabilities:		
Accounts payable	$ 295,689	$ 184,400
Accrued liabilities	159,897	201,967
Deferred tax liabilities	—	61,683
Derivatives	1,155	721
Total current liabilities	456,741	448,771
Long-term liabilities:		
Long-term debt	860,878	748,362
Derivatives	4,196	68
Asset retirement obligations	43,938	44,023

Deferred tax liabilities	502,189	337,961
Other long-term liabilities	9,595	8,715
Total long-term liabilities	1,420,796	1,139,129
Shareholders' equity:		
Preference shares, $0.01 par value; 200,000,000 authorized shares; zero issued at December 31, 2015 and December 31, 2014	—	—
Common shares, $0.01 par value; 2,000,000,000 authorized shares; 393,902,643 and 392,443,048 issued at December 31, 2015 and 2014, respectively	3,939	3,924
Additional paid-in capital	1,933,189	1,860,190
Accumulated deficit	(564,686)	(494,850)
Accumulated other comprehensive income	—	767
Treasury stock, at cost, 8,812,054 and 5,555,088 shares at December 31, 2015 and 2014, respectively	(46,929)	(31,072)
Total shareholders' equity	1,325,513	1,338,959
Total liabilities and shareholders' equity	$ 3,203,050	$ 2,926,859

See accompanying notes.

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KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)

	Years Ended December 31,		
	2015	2014	2013
Revenues and other income:			
Oil and gas revenue	$ 446,696	$ 855,877	$ 851,212
Gain on sale of assets	24,651	23,769	—
Other income	209	3,092	941
Total revenues and other income	471,556	882,738	852,153
Costs and expenses:			
Oil and gas production	105,336	100,122	96,791
Exploration expenses	156,203	93,519	230,314
General and administrative	136,809	135,231	158,421
Depletion and depreciation	155,966	198,080	222,544
Interest and other financing costs, net	37,209	45,548	47,590
Derivatives, net	(210,649)	(281,853)	17,027
Restructuring charges	—	11,742	—
Other expenses, net	5,246	2,081	3,512
Total costs and expenses	386,120	304,470	776,199
Income before income taxes	85,436	578,268	75,954
Income tax expense	155,272	298,898	166,998