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

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.

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.

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(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)		
es ry	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
ped	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 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

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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;

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- 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

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.

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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.

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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.

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

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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.

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

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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 expo