

Kosmos Energy Ltd.
Form 10-K/A
January 31, 2013

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**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION**
Washington, D.C. 20549

**FORM 10-K/A
Amendment No. 1**

(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, 2011

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
(State or other jurisdiction of
incorporation or organization)

98-0686001
(I.R.S. Employer Identification No.)

Clarendon House
2 Church Street
Hamilton, Bermuda
(Address of principal executive offices)

HM 11
(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

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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 Smaller reporting company
(Do not check if a 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 \$1,351,055,403.

The number of the registrant's Common Shares outstanding as of February 17, 2012 was 390,098,205.

DOCUMENTS INCORPORATED BY REFERENCE

Part III, Items 10-14, is incorporated by reference from the Proxy Statement for the Annual Meeting of Shareholders to be held on May 11, 2012.

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

EXPLANATORY NOTE

We are filing this Amendment No. 1 on Form 10-K/A (the "Amended Filing") to our Annual Report on Form 10-K for the year ended December 31, 2011 originally filed with the Securities and Exchange Commission ("SEC") on March 1, 2012 (the "Original Filing") to present net income per share attributable to common shareholders for the period from the date of our Corporate Reorganization, May 16, 2011, to December 31, 2011, and to remove the previously presented pro forma net income per share attributable to common shareholders on the face of our consolidated statements of operations, to revise the weighted average number of shares used to compute net income per share attributable to common shareholders, and to update the related disclosures found in Part II Item 6. Selected Financial Data and Item 8. Financial Statements and Supplementary Data.

In accordance with applicable SEC rules, this Amended Filing includes certifications from our Chief Executive Officer and Chief Financial Officer dated as of the date of this filing.

Except for the items noted above, no other information included in the Original Filing is being amended by this Amended Filing. The Amended Filing continues to speak as of the date of the Original Filing and we have not updated the Original Filing to reflect events occurring subsequent to the date of the Original Filing other than those associated with the presentation of net income per share attributable to common shareholders and the weighted average number of shares used to compute net income per share attributable to common shareholders on our consolidated statements of operations and in the related disclosure. Accordingly, this Amended Filing should be read in conjunction with our filings made with the SEC subsequent to the date of the Original Filing.

Background of the Restatement

We are filing this amendment to present net income per share attributable to common shareholders for the period subsequent to our Corporate Reorganization instead of the pro forma net income per share attributable to common shareholders previously presented. For the period from May 16, 2011 to December 31, 2011, the basic and diluted net income per share attributable to common shareholders of \$0.09 on our consolidated statements of operations is greater than our original presentation of pro forma basic and diluted net income per share attributable to common shareholders of \$0.06 even though our total earnings for the year ended December 31, 2011 have not changed. For the periods presented prior to our corporate reorganization, we do not calculate historical net income per share attributable to common shareholders because we did not have common stock outstanding, as defined in accounting literature, in those periods. For more information regarding the calculation of net income per share attributable to common shareholders, please refer to Note 16 Net Income Per Share (Restated).

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Unless otherwise stated in this report, references to "Kosmos," "we," "us" or "the company" refer to Kosmos Energy Holdings and its subsidiaries prior to the completion of the corporate reorganization, which was completed in connection with our initial public offering ("IPO"), and Kosmos Energy Ltd. and its subsidiaries as of the completion of the corporate reorganization and thereafter. 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 SELECT ABBREVIATIONS**

The following are abbreviations and definitions of certain terms 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.

<i>"2D seismic data"</i>	Two-dimensional seismic data, serving as interpretive data that allows a view of a vertical cross-section beneath a prospective area.
<i>"3D seismic data"</i>	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.
<i>"API"</i>	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.
<i>"ASC"</i>	Financial Accounting Standards Board Accounting Standards Codification.
<i>"ASU"</i>	Financial Accounting Standards Board Accounting Standards Update.
<i>"Barrel" or "bbl"</i>	A standard measure of volume for petroleum corresponding to approximately 42 gallons at 60 degrees Fahrenheit.
<i>"Bbbl"</i>	Billion barrels of oil.
<i>"Bboe"</i>	Billion barrels of oil equivalent.
<i>"Bcf"</i>	Billion cubic feet.
<i>"boe"</i>	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.
<i>"boepd"</i>	Barrels of oil equivalent per day.
<i>"bopd"</i>	Barrels of oil per day.
<i>"bwpd"</i>	Barrels of water per day.
<i>"Developed acreage"</i>	The number of acres that are allocated or assignable to productive wells or wells capable of production.
<i>"Development"</i>	The phase in which an oil or natural gas field is brought into production by drilling development wells and installing appropriate production systems.
<i>"Dry hole"</i>	A well that has not encountered a hydrocarbon bearing reservoir expected to produce in commercial quantities.
<i>"E&P"</i>	Exploration and production.
<i>"FASB"</i>	Financial Accounting Standards Board.
<i>"Farm-in"</i>	An agreement whereby an oil company acquires a portion of the working interest in a block from the owner of such interest, usually in return for cash and for taking on a portion of the drilling of one or more specific wells or other performance by the assignee as a condition of the assignment.
<i>"FPSO"</i>	Floating production, storage and offloading vessel.
<i>"Mbbl"</i>	Thousand barrels of oil.
<i>"Mcf"</i>	Thousand cubic feet of natural gas.
<i>"Mcfpd"</i>	Thousand cubic feet per day of natural gas.

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<i>"Mmbl"</i>	Million barrels of oil.
<i>"Mmboe"</i>	Million barrels of oil equivalent.
<i>"Mmcf"</i>	Million cubic feet of natural gas.
<i>"Natural gas liquid" or "NGL"</i>	Components of natural gas that are separated from the gas state in the form of liquids. These include propane, butane, and ethane, among others.
<i>"Petroleum Contract"</i>	A contract in which the owner of minerals gives an E&P company temporary and limited rights to explore for, develop, and produce minerals from the lease area.
<i>"Petroleum System"</i>	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 from the area in which it was formed to a reservoir rock where it can accumulate.
<i>"Plan of development" or "PoD"</i>	A written document outlining the steps to be undertaken to develop a field.
<i>"Productive well"</i>	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.
<i>"Prospect(s)"</i>	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 them fail neither oil nor natural gas will be present, at least not in commercial volumes.
<i>"Proved reserves"</i>	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).
<i>"Proved developed reserves"</i>	Proved developed reserves are those proved reserves that can be expected to be recovered through existing wells and facilities and by existing operating methods.
<i>"Proved undeveloped reserves"</i>	Proved undeveloped reserves are 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.
<i>"Shelf margin"</i>	The path created by the change in direction of the shoreline in reaction to the filling of a sedimentary basin.
<i>"Structural trap"</i>	A structural trap is 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.
<i>"Structural-stratigraphic trap"</i>	A structural-stratigraphic trap is a combination trap with structural and stratigraphic features.
<i>"Stratigraphy"</i>	The study of the composition, relative ages and distribution of layers of sedimentary rock.

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<i>"Stratigraphic trap"</i>	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.
<i>"Submarine fan"</i>	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.
<i>"Three-way fault trap"</i>	A structural trap where at least one of the components of closure is formed by offset of rock layers across a fault.
<i>"Trap"</i>	A configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not migrate.
<i>"Undeveloped acreage"</i>	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 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, Cameroon, Morocco 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 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 risks and other operational and environmental hazards;

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current and future government regulation of the oil and gas industry;

cost of compliance with laws and regulations;

changes in environmental, health and safety or climate change laws, greenhouse gas regulation or the implementation, or interpretation, of those laws and regulations;

environmental liabilities;

geological, technical, drilling, production and processing problems;

military operations, civil unrest, terrorist acts, wars or embargoes;

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the cost and availability of adequate insurance coverage;

our vulnerability to severe weather events; and

other risk factors discussed in the "Item 1A. Risk Factors" section of this annual report on Form 10-K.

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

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PART I

Item 1. Business

General

We are an independent oil and gas exploration and production company currently focused on frontier and emerging areas in Africa and South America. Our asset portfolio includes existing production, major discoveries and exploration prospects offshore Ghana, as well as exploration licenses offshore Morocco and Suriname and onshore Cameroon. Kosmos is listed on the New York Stock Exchange ("NYSE") under the ticker symbol "KOS."

Following our formation in 2003, we acquired our initial portfolio of exploration licenses and established a new, major oil province in West Africa with the discovery of the Jubilee Field within the Tano Basin 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. Oil production from the Jubilee Field commenced on November 28, 2010, and we generated revenues of \$666.9 million during 2011 from oil sales from the Jubilee Field.

In the near-term, we are focused on maximizing production from the Jubilee Field development, and progressing the appraisal and development of our other discoveries in Ghana as well as the acquisition, exploration, appraisal and development of existing and new opportunities, including identifying, capturing and testing additional high-potential prospects to grow reserves and production.

Our Business Strategy

Grow proved reserves and production through exploration, appraisal and development

We plan to continue to produce and further develop the Jubilee Field, while completing appraisal of our existing discoveries (Tweneboa, Tweneboa Deep, Enyenra and Ntomme in the Deepwater Tano Block offshore Ghana ("DT Block") and Mahogany East, Teak, Akasa and Banda in the West Cape Three Points Block offshore Ghana ("WCTP Block")). In the event of a declaration of commerciality and approval of a plan of development, we intend to develop these discoveries to grow proved reserves and production. We also plan to drill exploration prospects in our asset portfolio, with the intent to further grow proved reserves and production should discoveries be made.

Apply our technically-driven culture, which fosters innovation and creativity, to continue our successful exploration and development program

We differentiate ourselves from other E&P companies through our approach to exploration and development. Our geoscientists, petroleum engineers and major projects personnel are pivotal 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 oil fields. Culturally, we have an open, team-oriented work environment that fosters both creative and contrarian thinking. This approach allows us to fully consider and understand risk and reward and to deliberately and collectively pursue strategies that maximize value. We used this philosophy and approach to make discoveries in and produce from the Tano Basin offshore Ghana, a significant new petroleum system the industry previously did not consider either prospective or commercially viable.

Focus on rapidly developing our discoveries to initial production

We focus on maximizing returns through accelerating development to deliver early production. If a phased development strategy is deemed to be the optimal solution, we will seek to implement the approach early in the process. There are numerous benefits to pursuing a phased development to support our production growth plan. Importantly, a phased development strategy can provide for first

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oil production earlier than could otherwise be possible using traditional development techniques, which are disadvantaged by more time-consuming, costly and sequential appraisal and pre-development activities. In certain circumstances, we believe a phased approach can optimize full-field development through a better understanding of dynamic reservoir behavior and allows numerous activities to be performed in a parallel rather than a sequential manner. The initial phase of the Jubilee Field, for example, was brought on production at an earlier date by using a phased development approach, with further appraisal and pre-development activities performed in parallel and detailed engineering for the initial phase conducted simultaneously with the other project activities. 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 in sequence, before first production is achieved. This adds considerably more time to the development timeline. A phased approach provides dynamic reservoir performance information that allows the full-field development to be optimized. This approach also maximizes net asset value by refining appraisal and 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 recoverability of reserves in the most economic manner. 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.

First oil production from the Jubilee Field commenced on November 28, 2010, and we received our first oil revenues in early 2011. This development timeline from discovery to first oil was significantly less than the industry average of seven to ten years and set a record for a deepwater development at this water depth in West Africa. This condensed timeline reflects the lessons learned by members of our experienced management while leading other large scale deepwater developments, such as Ceiba offshore Equatorial Guinea and Neptune and Mensa in the U.S. Gulf of Mexico.

Identify, access and explore emerging regions and hydrocarbon plays

Our management and exploration team has demonstrated an ability to identify regions and hydrocarbon plays that yield multiple large commercial discoveries. We will continue to utilize our systematic and proven geologically focused approach to 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 oil potential. This was the case with respect to the Late Cretaceous stratigraphy of West Africa, the niche in which we chose to build our exploration portfolio between 2004 and 2006. Many of our licenses share similar geologic characteristics focused on untested structural-stratigraphic traps. This exploration focus has proved successful, with the discovery of the Jubilee Field ushering in a new level of industry interest in Late Cretaceous petroleum systems across the Atlantic Margin, including play types that had previously been largely ignored.

This approach and focus, coupled with a first-mover advantage, provide a competitive advantage in identifying and accessing new strategic growth opportunities. We expect to continue to seek new opportunities where oil has not been discovered or produced in meaningful quantities by leveraging the skills of our experienced technical team. This includes our existing areas of interest as well as selectively expanding into other regions.

We may farm-in to 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 replenish and expand our asset portfolio.

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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 particular consideration to those attributes that lead to working petroleum systems. The process includes basin modeling to predict oil 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 and seismic data available to Kosmos. 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 support and preserve hydrocarbon accumulation. Once an area is high-graded based on this play/fairway analysis, geophysical analysis is conducted to identify prospective traps of interest.

Alongside the subsurface analysis, Kosmos performs an analysis of country-specific risks to gain a comprehensive 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 iterative and comprehensive 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 actively targets licenses over the particular basin or fairway in order 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. Additional objectives include 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 operate in the oil and gas exploration and production industry and have operations in Africa and South America. Currently, all revenues are generated from our operations offshore Ghana. Oil produced from West Africa, including the Jubilee Field, has generally priced in reference to Dated Brent crude. Brent crude is produced in the North Sea and is widely accepted by the oil and gas industry as the most representative of the global physical standards for the oil market in comparison to other reference oils, such as West Texas Intermediate ("WTI"). The location of the Jubilee Field offshore Ghana allows us to sell our oil to the major refining markets of North America, Asia and Europe. Due to its quality, oil from the Jubilee Field generally sells for a slight premium relative to Dated Brent.

Information about our discoveries and prospects are summarized below. In interpreting this information, general reference should be made to the risk factors as a whole and specific reference should be made to the subsections of this annual report on Form 10-K titled "Item 1A. Risk Factors 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," "Item 1A. Risk Factors 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" and "Item 1A. Risk Factors 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.

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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."

Our Discoveries

Information about our discoveries is summarized in the following table.

Discoveries	License	Areal Extent (acres)	Kosmos Working Interest	Block Operator(s)	Stage	Type	Expected Year of PoD Submission
Ghana							
Jubilee Field Phase 1(1)(2)	WCTP/DT(3)	8,300	24.0771%(5)	Tullow/Kosmos(6)	Production	Deepwater	2008(2)
Jubilee Field subsequent phases(1)(2)	WCTP/DT(3)	4,600	24.0771%(5)	Tullow/Kosmos(6)	Development Development	Deepwater	2011(7)
Mahogany East	WCTP(4)	6,600	30.8750%	Kosmos	planning	Deepwater	2011
Teak	WCTP(4)	23,000	30.8750%	Kosmos	Appraisal	Deepwater	2013
Akasa	WCTP(4)(8)	4,900	30.8750%	Kosmos	Appraisal	Deepwater	2014
Banda	WCTP(4)(8)	25,000	30.8750%	Kosmos	Appraisal	Deepwater	2014
Tweneboa	DT(4)(8)	27,000	18.0000%	Tullow	Appraisal	Deepwater	2013
Enyenra	DT(4)	28,100	18.0000%	Tullow	Appraisal	Deepwater	2012
Ntomme	DT(4)(8)	19,100	18.0000%	Tullow	Appraisal	Deepwater	2012

- (1) For information concerning our estimated proved reserves in the Jubilee Field as of December 31, 2011, see " Our Reserves."
- (2) The Jubilee Phase 1 PoD was submitted to Ghana's Ministry of Energy in December 2008 and was formally approved in July 2009. The Jubilee Phase 1 PoD details the necessary wells and infrastructure to develop two of the reservoirs within the Jubilee Field. Oil production from the Jubilee Field offshore Ghana commenced on November 28, 2010, and we received our first oil revenues in early 2011. We intend to submit or amend PoDs for other reservoirs within the Jubilee Unit for the Jubilee Field subsequent phases to Ghana's Ministry of Energy for approval in order to extend the production plateau of the Jubilee Field, although we can give no assurance that such approvals will be forthcoming. See (7) below.
- (3) The Jubilee Field straddles the boundary between the WCTP Block and the DT Block offshore Ghana. Consistent with the Ghanaian Petroleum Law, the WCTP Petroleum Agreement ("WCTP PA") and DT Petroleum Agreement ("DT PA") and as required by Ghana's Ministry of Energy, in order to optimize resource recovery in this field, we entered into the Unitization and Unit Operating Agreement (the "UUA") in July 2009 with Ghana National Petroleum Corporation ("GNPC") and the other block partners of each of these two blocks. The UUA governs the interests in and development of the Jubilee Field and created the Jubilee Unit from portions of the WCTP Block and the DT Block.
- (4) 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. In order to acquire the additional paying interest, GNPC must notify the contractor of its intention to acquire such interest within sixty to ninety days of the contractor's notice to Ghana's Ministry of Energy of a commercial discovery. These interest percentages do not give effect to the exercise of such options.
- (5) These interest percentages are subject to redetermination of the working interests in the Jubilee Field pursuant to the terms of the UUA. See "Item 1A. Risk Factors The unit partners' respective interests in the Jubilee Unit are subject to redetermination and our interests in such unit may decrease as a result" and " Significant Exploration Agreements Jubilee Field Unitization." GNPC has exercised its WCTP PA and DT PA options, with respect to the Jubilee Unit, to acquire an additional unitized paying interest of 3.64084% in the Jubilee Field. The Jubilee Field interest percentages give effect to the exercise of such option.
- (6) Kosmos is the Technical Operator and Tullow Ghana Limited, a subsidiary of Tullow Oil plc ("Tullow"), is the Unit Operator of the Jubilee Unit. See " Significant Exploration Agreements Jubilee Field Unitization."
- (7) The Jubilee Phase 1A PoD was submitted to Ghana's Ministry of Energy on December 18, 2011 and was formally approved in January 2012. The Jubilee Phase 1A PoD details the necessary wells and infrastructure to further develop the existing producing reservoirs and develop a third reservoir within the Jubilee Field.

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(8)

The areal extent for these discoveries were determined based on estimates derived internally by the Company and represents the possible upside areal extent for these discoveries. In future periods, should we have our independent petroleum engineers assess these discoveries, such estimates may change. Additionally, such estimates may change as a result of future assessment and appraisal activities. See Item 1A. Risk Factors We face substantial uncertainties in estimating the characteristics of our unappraised discoveries and our prospects."

Table of Contents**Ghana Well Information**

Information about the wells we have drilled on our license areas in Ghana is summarized in the following table.

Jubilee	Operator	Spud Date(1)	Total Depth (feet)	Net Hydrocarbon Pay (feet)	Status(2)	Comments
J-09 (Mahogany-1)	Kosmos	05/30/07	12,553	321	Producing	Discovery well for Jubilee in WCTP Block. Drill stem tested at rates in excess of 20,500 bopd. Lower completion installed.
Hyedua-1	Tullow	07/27/07	13,130	180	Plugged Back	Downdip confirmation well in DT Block.
J-10 Water Injector ("WI") (Hyedua-1BP1)	Tullow	07/27/07	12,631	136	Injecting	Whole core obtained. Injectivity test conducted at rates in excess of 20,000 bwpd. Down structure water injector.
J-16GI Gas Injectors ("GI") (Mahogany-2)	Tullow	03/06/08	11,296	164	Injecting	Updip confirmation well for Jubilee reservoirs. Whole core obtained. Updip gas injector.
J-08 (Hyedua-2)	Tullow	10/09/08	12,018	180	Producing	Drill stem tested at rates in excess of 16,500 bopd. Whole core obtained.
J-04	Tullow	01/17/09	15,121	90	Plugged Back	Tested the Southeastern edge of the Jubilee fairway.
J-04 Sidetrack ("ST")	Tullow	01/17/09	13,803	199	Producing	Observation well for interference testing.
J-01	Tullow	03/18/09	12,411	140	Producing	
J-02	Tullow	03/25/09	13,829	186	Producing	Observation well for interference testing.
J-11WI	Tullow	05/06/09	13,822	121	Injecting	Down structure water injector.
J-12WI	Tullow	05/11/09	14,081	188	Injecting	Down structure water injector.
J-15WI	Tullow	05/14/09	16,949	47	Injecting	Only drilled through Upper Mahogany down structure water injector.
J-07	Tullow	05/19/09	13,599	121	Plugged Back	Whole core obtained.
J-07ST	Tullow	05/19/09	13,701	116	Plugged Back	
J-07ST2	Tullow	05/19/09	14,341	184	Producing	
J-03	Tullow	09/29/09	12,507	173	Producing	
J-05	Tullow	07/08/09	13,753	193	Producing	Lower completion installed.
J-17	Tullow	10/07/09	19,390	174	Plugged Back	Only drilled through Upper Mahogany reservoirs.
J-17STGI	Tullow	10/07/09	19,574	197	Injecting	Updip gas injector.
J-13WI	Tullow	10/10/09	13,058	143	Injecting	Down structure water injector.
J-14WI	Tullow	10/14/09	13,999	77	Injecting	Down structure water injector.
J-06	Tullow	04/13/11	12,959	147	Plugged back	
J-06ST1	Tullow	06/26/11	13,091	126	Producing	

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	Operator	Spud Date(1)	Total Depth (feet)	Net Hydrocarbon Pay (feet)	Status(2)	Comments
Mahogany East						
Mahogany-3	Kosmos	11/27/08	14,262	108	Suspended	Discovery well for Mahogany Deep.
Mahogany-4	Kosmos	08/28/09	12,074	141	Suspended	Updip confirmation well for the Mahogany East reservoirs.
Mahogany Deep-2	Kosmos	09/29/09	14,193	49	Suspended	Drilled to delineate deep reservoirs.
Mahogany-5	Kosmos	04/18/10	13,084	75	Suspended	Eastern confirmation of Mahogany East reservoirs.
Odum						
Odum-1	Kosmos	01/18/08	11,109	72	Abandoned	Discovery well for Odum. Subsequently not declared commercial.
Odum-2	Kosmos	11/12/09	8,222	66	Abandoned	Confirmation well for Odum. Subsequently not declared commercial.
Tweneboa						
Tweneboa-1	Tullow	01/26/09	13,002	69	Suspended	Discovery well for Tweneboa condensate pays.
Tweneboa-2	Tullow	12/06/09	13,878	105	Suspended	Confirmation well for Tweneboa. Discovery of Central Oil Channel below condensate pays. Whole core obtained.
Tweneboa-3	Tullow	11/26/10	12,811	29	Plugged back	Confirmation well for Tweneboa.
Tweneboa-3ST	Tullow	12/22/10	12,816	112	Suspended	Discovery well for Ntomme.
Tweneboa-4	Tullow	01/16/11	13,146	59	Suspended	Confirmation well for Tweneboa.
Onyina						
Onyina-1	Tullow	09/25/10			Abandoned	Dry hole.
Enyenra (formerly known as Owo)						
Owo-1	Tullow	06/10/10	12,766	174	Plugged Back	Discovery well for Enyenra.
Owo-1 ST1	Tullow	07/28/10	13,117	115	Suspended	Lateral confirmation well for Enyenra channels, and discovery wells for deeper condensate pays. Whole core obtained.
Owo-1 RA	Tullow	10/18/11	12,779	157	Suspended	
Enyenra-2	Tullow	01/22/11	13,887	121	Suspended	Downdip confirmation well for Enyenra channels. Discovery well for Tweneboa Deep.
Enyenra-3A	Tullow	04/20/11	13,205	56	Suspended	Updip confirmation well for Enyenra channels.
Teak						
Teak-1	Kosmos	12/21/10	10,398	239	Suspended	Discovery well for Teak.
Teak-2	Kosmos	02/12/11	11,184	89	Suspended	Drilled fault block adjacent to Teak-1 discovery.
Teak-3	Kosmos	10/6/11	10,571	115	Suspended	Northern extension of Teak discovery.
Dahoma						
Dahoma-1	Kosmos	02/04/10	14,403		Abandoned	Dry hole.

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	Operator	Spud Date(1)	Total Depth (feet)	Net Hydrocarbon Pay (feet)	Status(2)	Comments
Banda						
Banda-1	Kosmos	03/31/11	15,026	10	Suspended	Discovery well for Banda. Well considered sub-commercial.
Makore						
Makore-1	Kosmos	04/25/11	12,717		Abandoned	Dry hole.
Akasa						
Akasa-1	Kosmos	07/13/11	12,856	108	Suspended	Discovery well for Akasa.
Ntomme						
Ntomme-2A	Tullow	11/09/11	13,156	128	Suspended	Confirmation for oil in Akasa discovery.

(1) In connection with our side-track wells, "spud date" refers to the date we commenced drilling such well.

(2) These terms have the following meanings:

Abandoned	Exploration / appraisal well that was deemed to have no further utility. The well was permanently abandoned, per approved government procedures.
Completion Pending	Production / Injection casing has been installed across the target interval as part of the normal drilling operations, and the well is scheduled / approved to have a completion installed to facilitate production / injection per the applicable PoD.
Injection Ready	Injection well has been drilled and completed. All well equipment is in place to commence injection.
Plugged Back	Well that has cement set across productive interval to facilitate production from sidetrack well.
Production Ready	Production well has been drilled and completed. All well equipment is in place to commence production.
Suspended	Exploration / appraisal well that has had production casing installed across the target interval. However, plans to utilize the well as part of a development have not yet been approved.

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Information about our prospects on our license areas in Ghana, Cameroon and our Cap Boujdour Offshore license area in Morocco is summarized in the following table. We are currently assessing prospectivity on our recently acquired license areas in Morocco, Cameroon and Suriname and accordingly information concerning prospects, if any, on such recently acquired license areas is not yet available. We currently are, and plan to continue, acquiring seismic information to assess the prospectivity for these license areas.

Prospect	License	Areal Extent (acres)	Kosmos Working Interest (%)	Block Operator	Type	Projected Spud Year(4)
Ghana(1)						
Cedrela	WCTP(5)(6)	3,400	30.875	Kosmos	Deepwater	2012
Odum East	WCTP(5)	3,100	30.875	Kosmos	Deepwater	Post 2012
Sapele	WCTP(5)	19,100	30.875	Kosmos	Deepwater	Post 2012
Funtum	WCTP(5)	6,700	30.875	Kosmos	Deepwater	Post 2012
Assin	WCTP(5)	2,600	30.875	Kosmos	Deepwater	Post 2012
Okoro	WCTP(5)	4,600	30.875	Kosmos	Deepwater	Post 2012
Late Cretaceous WCTP Play (4 identified targets)	WCTP(5)	8,100	30.875	Kosmos	Deepwater	Post 2012
Turonian Deep	DT	23,000	18.000	Tullow	Deepwater	2012
DT Sapele	DT	4,600	18.000	Tullow	Deepwater	2012
Wawa	DT	9,100	18.000	Tullow	Deepwater	2012
Walnut	DT	2,900	18.000	Tullow	Deepwater	Post 2012
Wassa	DT	8,900	18.000	Tullow	Deepwater	Post 2012
Adinkra	DT	1,300	18.000	Tullow	Deepwater	Post 2012
Oyoko	DT	1,900	18.000	Tullow	Deepwater	Post 2012
Ananta	DT	1,600	18.000	Tullow	Deepwater	Post 2012
Cameroon(2)						
Sipo (formerly known as Liwenyi)	Ndian River	4,000	100.000	Kosmos	Onshore	2012
Liwenyi South	Ndian River	1,600	100.000	Kosmos	Onshore	Post 2012
Meme	Ndian River	3,800	100.000	Kosmos	Onshore	Post 2012
Bamusso	Ndian River	12,100	100.000	Kosmos	Onshore	Post 2012
Morocco(3)						
Gargaa	Cap Boujdour Offshore	13,900	75.000	Kosmos	Deepwater	Post 2012
Argane	Cap Boujdour Offshore	11,600	75.000	Kosmos	Deepwater	Post 2012
Safsaf	Cap Boujdour Offshore	22,400	75.000	Kosmos	Deepwater	Post 2012
Aarar	Cap Boujdour Offshore	8,100	75.000	Kosmos	Deepwater	Post 2012
Zitoune	Cap Boujdour Offshore	10,000	75.000	Kosmos	Deepwater	Post 2012
Al Arz	Cap Boujdour Offshore	13,400	75.000	Kosmos	Deepwater	Post 2012
Felline	Cap Boujdour Offshore	13,500	75.000	Kosmos	Deepwater	Post 2012
Nakhil	Cap Boujdour Offshore	6,500	75.000	Kosmos	Deepwater	Post 2012
Barremian Tilted Fault Block Play (8 identified structures)	Cap Boujdour Offshore	49,400	75.000	Kosmos	Deepwater	Post 2012

(1)

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. In order to acquire the additional paying interests, GNPC must notify the contractor of its intention to do so within sixty to ninety days of the contractor's notice to Ghana's Ministry of Energy of a commercial discovery. These interest percentages do not give effect to the exercise of such options.

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- (2) The Republic of Cameroon has an option to acquire an interest of up to 15.0% in a commercial discovery on the Ndiar River Block. These interest percentages do not give effect to the exercise of such options. The table does not include the license information for the Fako Block in Cameroon, which we entered into in January 2012.
- (3) We have not yet made a decision as to whether or not to drill our Morocco prospects within the Cap Boujdour Offshore Block. If we decide to continue into the drilling phase of the license, we anticipate that the first well to drill within the Cap Boujdour Offshore Block will be post 2012.
- (4) See "Item 1A. Risk Factors 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" and "Item 1A. Risk Factors 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."
- (5) In July 2011, at the end of the seven-year exploration phase, parts of the WCTP Block, which include these prospects, were subject to relinquishment. We and our WCTP Block partners have certain rights to negotiate a new petroleum contract with respect to these areas. We and our WCTP Block partners exercised such right in July 2010 and formally submitted a new petroleum agreement for such areas in early October 2011. We and our WCTP Block partners, the Ghana Ministry of Energy and GNPC have agreed such WCTP PA rights 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 these areas. See " Ghana."
- (6) We have disputed the relinquishment of the area around the Cedrela prospect. See " Ghana" and "Item 1A. Risk Factors We 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."

Ghana

The WCTP and DT Blocks are located within the Tano Basin, offshore Ghana. This basin contains a proven world-class petroleum system as evidenced by our discoveries.

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 prospect 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.

Kosmos is the operator of the WCTP Block and holds a 30.9% participating interest. The WCTP PA, which governs our activities related to the WCTP Block, has a duration of 30 years from its effective date (July 2004); however, in July 2011, at the end of the seven-year exploration phase, 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 subject to relinquishment ("WCTP Relinquishment Area"). Our existing discoveries within the WCTP Block (Akasa, Banda, Mahogany

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East and Teak) have not been relinquished, as the WCTP PA remains in effect after the end of the exploration phase. In addition, we have disputed the relinquishment of the area around the Cedrela prospect. In July 2011, immediately prior to Kosmos receiving the drilling rig from another operator, damage to the rig incurred during preparations to move the rig to the WCTP Block operations rendered the rig incapable of drilling the Cedrela-1 exploration well prior to the end of the WCTP exploration period on July 21, 2011. As a result of this unforeseen delay in the drilling of the Cedrela-1 exploration well, the Company, as Operator for the WCTP PA Block partners, delivered a Notice of Force Majeure. The Ministry of Energy and GNPC did not agree this event was Force Majeure. On August 24, 2011, we as Operator of the WCTP Block and on behalf of the WCTP Block partners, delivered a Notice of Dispute to the Ministry of Energy and GNPC as provided under the WCTP PA, which is the initial step in triggering the formal dispute resolution process under the WCTP PA with the Government of Ghana regarding our rights to drill the Cedrela-1 exploration well. This Notice of Dispute establishes a process for negotiation and consultation for a period of 30 days (or longer if mutually agreed) among senior representatives from the Ministry of Energy, GNPC and the WCTP Block partners to resolve the matter. The issue continues to be discussed in an effort to reach a mutually agreed upon resolution among the parties. See "Item 1A. Risk Factors We 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."

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 exercised such right in July 2010 and formally submitted a proposed new petroleum agreement for the WCTP Relinquishment Area in early 2011. We and our WCTP Block partners, the Ghana Ministry of Energy and GNPC have agreed such WCTP PA rights extend from July 21, 2011 until such time as either a new petroleum agreement 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.

Kosmos holds a non-operated 18.0% participating interest in the DT Block. The DT PA, which governs our activities relating to the DT Block, has a duration of 30 years from its effective date. The seven-year exploration phase of the DT PA will expire in January 2013. Our existing discoveries within the DT Block (Tweneboa, Enyenra and Ntomme) are not subject to relinquishment upon expiration of the exploration phase of the DT PA, as the DT PA remains in effect after the end of the exploration phase. We and our DT Block partners have certain rights of first refusal for the granting of a new petroleum contract and certain rights to negotiate a new petroleum contract with respect to areas of the DT Block that are subject to relinquishment under the DT PA; that is acreage not within a discovery area, development and production area or the Jubilee Unit ("DT Relinquishment Area"). We and our DT Block partners exercised such right to negotiate a new petroleum contract in January 2012.

One of our DT Block partners, Sabre Oil and Gas Limited ("Sabre"), provided notice that it intends to transfer all of its 4.05% participating interest in the DT Block to a third party for approximately \$365.0 million, with up to \$45.0 million in contingent payments upon achieving certain performance milestones. Under the DT Joint Operating Agreement, each of the DT Block partners have a right of first refusal regarding the transfer of such interest to a third party, assuming the block partner is willing to match the terms and conditions of the existing offer of the third party. On February 23, 2012, we exercised our right to accept the terms and conditions of the proposed transfer. Subject to Government of Ghana consent, we anticipate the transaction to close during the second quarter of 2012. After the acquisition, our interest in the DT Block and Jubilee Unit will increase to 22.05% and 25.82258%, respectively.

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Our Ghanaian Discoveries

The following is a brief discussion of our discoveries to date on our license areas offshore Ghana. See "Item 1A. Risk Factors We face substantial uncertainties in estimating the characteristics of our unappraised discoveries and our prospects."

Jubilee Discovery

The Jubilee Field was discovered by Kosmos in 2007 within the WCTP Block. An appraisal well was subsequently drilled in the offsetting DT Block, confirming a large accumulation of oil underlying areas within both blocks. The Jubilee Field is located approximately 37 miles (60 kilometers) offshore Ghana in water depths of 3,250 to 5,800 feet (991 to 1,707 meters). Pursuant to the terms of the UUOA, the discovery area was unitized for purposes of joint development by the WCTP and DT Block participating interest holders. The UUOA specifies a split operatorship role. Kosmos was the Technical Operator for Development and Tullow was designated as the Unit Operator. The initial tract participations were 50% for each block. Pursuant to the terms of the Jubilee Field UUOA, the percentage is subject to a process of redetermination. 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 54.36660% for the WCTP Block and 45.63340% for the DT Block. Our Unit Interest was increased from 23.50868% (our percentage after Tullow's acquisition of EO Group Limited ("EO Group") see "Item 8. Financial Statements and Supplementary Data Note 5 Joint Interest Billings") to 24.07710%. See "Item 1A. Risk Factors 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 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 location of the Jubilee Field led to the decision to implement an FPSO based development plan. The "Kwame Nkrumah" FPSO has a design capacity of processing approximately 120,000 bopd of oil, 160,000 Mcf/d of natural gas, and storing up to 1.6 Mmmbbl of stabilized crude. Further, the vessel can provide water and natural gas injection of 232,000 bwpd and 160,000 Mcf/d, respectively, to support reservoir pressure. The Phase 1 development focused on partial development of certain reservoirs in the Jubilee Field. The Kosmos-led integrated project team successfully executed an initial 17 well development plan, which included nine producing wells, six water injection wells and two natural gas injection wells, the FPSO and subsea infrastructure. This initial phase provided infrastructure capacity for additional production and injection wells that could potentially be drilled in future phases of development. Future phases include the further development of the existing producing reservoirs and development of the three remaining reservoirs to maximize ultimate recovery.

The Jubilee Unit partners are currently performing remediation efforts on certain of the producing wells in the Phase 1 development. Optimized completion techniques are being implemented which are expected to mitigate the near wellbore productivity issues experienced in certain wells.

The Jubilee Field Phase 1A development at Jubilee was approved in 2012 by the Government of Ghana. The Phase 1A development began in 2012 and is expected to include eight new wells, including five production wells and three water injection wells, as well as an expanded subsea infrastructure.

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WCTP Block Discoveries

The Mahogany East area is located within the WCTP Block, southeast of the Jubilee Field. The field is approximately 37 miles (60 kilometers) offshore Ghana in water depths of 4,101 to 5,905 feet (1,250 to 1,800 meters). 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 Mahogany-3, Mahogany-4, Mahogany-5 and Mahogany Deep-2 wells have intersected multiple oil bearing reservoirs in a Turonian turbidite sequence. Fluid samples recovered from the wells indicate an oil gravity of between 31 and 37 degrees API.

The Mahogany East area, a combined area covering parts of the Mahogany discovery and the Mahogany Deep discovery area was declared commercial in September 2010, and a PoD was submitted to Ghana's Ministry of Energy as of May 2, 2011. In a letter dated May 16, 2011, the Minister of Energy did not approve the PoD and requested that the WCTP Block partners take certain steps regarding notifications of discovery and commerciality; and requested other information. The WCTP Block partners believe the combined submission was proper and have held meetings with GNPC which resolved issues relating to the PoD work program. From May 2011, the Ministry of Energy, GNPC and the WCTP Block partners continued working to resolve other differences; however, the WCTP PA contains specific timelines for PoD approval and discussions, which expired at the end of June 2011. On June 30, 2011, we as Operator of the WCTP Block and on behalf of the WCTP Block partners, delivered a Notice of Dispute to the Ministry of Energy and GNPC as provided under the WCTP PA, which is the initial step in triggering the formal dispute resolution process under the WCTP PA with the Government of Ghana regarding approval of the Mahogany East PoD. This Notice of Dispute establishes a process for negotiation and consultation for a period of 30 days (or longer if mutually agreed) among senior representatives from the Ministry of Energy, GNPC and the WCTP Block partners to resolve the matter. We and the WCTP Block partners are in discussions with the Ministry of Energy and GNPC to resolve differences on the PoD.

The Teak discovery is located in the western portion of the WCTP Block, northeast of the Jubilee Field. The field is approximately 31 miles (50 kilometers) offshore Ghana in water depths of approximately 650 to 3,600 feet (200 to 1,100 meters). We believe the field is a structural-stratigraphic trap with an element of four-way closure. The Teak-1, Teak-2 and Teak-3 wells have intersected multiple oil and natural gas condensate bearing reservoirs in Campanian and Turonian zones. Fluid samples recovered from the wells indicate an oil gravity of between 32 and 39 degrees API and natural gas condensate gravity of between 40 and 45 degrees API.

The Akasa discovery is located in the western portion of the WCTP Block approximately 31 miles (50 kilometers) offshore Ghana in water depths of approximately 3,200 to 5,050 feet (950 to 1,550 meters). 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 Banda discovery is located in the southeastern portion of the WCTP Block. The field is approximately 27 miles (43 kilometers) offshore Ghana in water depths of approximately 1,800 to 4,900 feet (550 to 1,500 meters). We believe the target reservoir is a channel fairway that is stratigraphically trapped. The Banda-1 well intersected quantities of oil-bearing reservoirs in Cenomanian to Albian zones, although the well is considered sub-commercial. The Banda discovery represents a new play in the WCTP Block.

Following additional appraisal, drilling and evaluation, a decision regarding the commerciality of these discoveries on the WCTP Block will be made by the WCTP Block partners. Should a

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

DT Block Discoveries

The Tweneboa discovery is located in the central portion of the DT Block approximately 31 miles (50 kilometers) offshore Ghana in water depths of approximately 3,281 to 5,252 feet (1,000 to 1,500 meters). We believe the field is a stratigraphic trap with reservoir intervals contained within a series of stacked Upper Cretaceous Turonian-aged, deepwater turbidite fan lobes and channel deposits. The Tweneboa-1, Tweneboa-2, Tweneboa-3, Tweneboa-3ST and Tweneboa-4 wells have intersected multiple natural gas condensate and oil bearing reservoirs in this Turonian turbidite sequence. Fluid samples recovered from the wells indicate an oil gravity of approximately 31 degrees API and a natural gas condensate gravity of between 41 and 47 degrees API.

The Enyenra discovery is located in the Western portion of the DT Block. The field is approximately 28 miles (45 kilometers) offshore Ghana in water depths of approximately 3,300 to 5,000 feet (1,000 to 1,500 meters). We believe the field is primarily a stratigraphic trap with reservoir intervals contained within a series of stacked Upper Cretaceous Turonian-aged, deepwater channel deposits. The Owo-1, Owo-1 ST1, Owo-1RA, Enyenra-2A and Enyenra-3A wells have intersected multiple oil and natural gas condensate bearing reservoirs in a Turonian turbidite sequence. Fluid samples recovered from the wells indicate an approximate oil gravity of 32 degrees API, and a natural gas condensate gravity of between 42 and 48 degrees API. We believe Enyenra is predominantly an oil accumulation.

The Ntomme discovery is located in the central portion of the DT Block. The field is approximately 32 miles (52 kilometers) offshore Ghana in water depths of approximately 3,950 to 5,700 feet (1,200 to 1,750 meters). We believe the field is a stratigraphic trap with reservoir intervals contained within a series of stacked Upper Cretaceous Turonian-aged, deepwater fan lobes and channel deposits. The Tweneboa-3ST well discovered the Ntomme discovery and the Ntomme-2A appraisal well confirmed a downdip extension of the field. The wells encountered high-quality stacked reservoir sandstones. The Ntomme-2A confirmed the majority of the resources in the discovery to be oil. Fluid samples recovered from the wells indicate an oil gravity of 35 degrees API.

The Tweneboa Deep discovery is located in the southern portion of the DT Block approximately 44 miles (70 kilometers) offshore Ghana in water depths of approximately 4,900 to 5,900 feet (1,500 to 1,800 meters). We believe the field comprises a north-south trending Upper Cretaceous Lower Turonian aged turbidite system. The Enyenra-2A well discovered Tweneboa Deep while testing a deeper Turonian fan where natural gas-condensate bearing sandstones were intersected. Fluid sampling from the Enyenra-2A well indicates an approximate natural gas condensate gravity of 46 degrees API. Pursuant to the terms of the DT PA, in September 2011, the operator notified the Ministry of Energy that the discovery did not at that time merit appraisal but that further studies would be performed prior to making a final decision on appraisal.

Following additional appraisal, drilling and evaluation, a decision regarding the commerciality of these discoveries on the DT Block will be made by the DT Block partners. Should a discovery be declared commercial, a PoD would be prepared for submission to Ghana's Ministry of Energy within six months of the declaration of commerciality.

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Our Ghanaian Prospects

WCTP Block

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 exercised such right in July 2010 and formally submitted a proposed new petroleum agreement for the WCTP Relinquishment Area in early 2011. We and our WCTP Block partners, the Ghana Ministry of Energy and GNPC have agreed such WCTP PA rights extend from July 21, 2011 until such time as either a new petroleum agreement 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. The following is a brief discussion of our prospects in the WCTP Relinquishment Area, should a new petroleum agreement be entered into for the WCTP Relinquishment Area.

Cedrela

Cedrela located in the southern most part of the WCTP block, approximately 42 miles (67 kilometers) offshore Ghana in water depths of approximately 4,950 to 5,650 feet (1,500 to 1,700 meters). It is located approximately three miles from the Dahoma-1 well and is defined by a high resolution seismic survey. The Cedrela prospect consists of Turonian through Albian sediments trapped within a fair way closure. See "Item 1A. Risk Factors We 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."

Odum East

Odum East is located in the eastern portion of the WCTP Block approximately 31 miles (50 kilometers) offshore Ghana in water depths of approximately 2,600 to 3,300 feet (800 to 1,000 meters). It is located 1.9 miles (3 kilometers) east of the Odum-1 and Odum-2 well penetrations and defined by a high resolution 3D seismic data survey as a combination structural-stratigraphic trap, and is very similar to the Odum discovery. The target interval is comprised of Upper Cretaceous Campanian aged stacked turbidite sequences. The first well to drill Odum East is anticipated to be spud post 2012.

Sapele

Sapele is located in the northern portion of the WCTP Block approximately 22 miles (35 kilometers) offshore Ghana in water depths of approximately 300 to 2,600 feet (100 to 800 meters). It targets an Upper Cretaceous Middle Campanian age system of amalgamated channels forming an extensive depositional system with associated facies confining the width of the stratigraphic trap to approximately 6.2 miles (10 kilometers) wide. High resolution 3D seismic information indicates the presence of submarine fan channels. The first well to drill Sapele is anticipated to be spud post 2012.

Funtum

Funtum is located in the northern portion of the WCTP Block approximately 22 miles (35 kilometers) offshore Ghana in water depths of approximately 300 to 1,600 feet (100 to 500 meters). It targets an Upper Cretaceous Middle Campanian age confined channel system approximately 1.3 miles (2 kilometers) wide with associated channel margin facies extending the stratigraphic trap to approximately 3.1 miles (5 kilometers) wide. High resolution 3D seismic information indicates the presence of a prospective submarine fan. The first well to drill Funtum is anticipated to be spud post 2012.

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Assin

Assin is located in the central portion of the WCTP Block approximately 31 miles (50 kilometers) offshore Ghana in water depths of approximately 2,600 to 3,300 feet (800 to 1,000 meters). It is approximately 2.5 miles (4 kilometers) northwest and updip of the Odum discovery. The stratigraphic trap is defined by a high resolution 3D seismic survey and is very similar in nature to the Odum discovery. The target interval is comprised of Upper Cretaceous, Campanian aged stacked turbidite sequences interlayered with marine shale. The first well to drill Assin is anticipated to be spud post 2012.

Okoro

Okoro is a tilted Albian fault block located in the central portion of the WCTP Block approximately 31 miles (50 kilometers) offshore Ghana in water depths of approximately 2,600 to 3,000 feet (800 to 900 meters). It sits adjacent to the Jubilee field but in older and deeper stratigraphy. Oil samples from deeper wells within Tano Basin have also recovered oil samples from Albian formations. The first well to drill Okoro is anticipated to be spud post 2012.

Late Cretaceous WCTP Play

Four additional Late Cretaceous targets are present on the WCTP Block offshore Ghana in water depths from 600 to 4,300 feet (190 to 1,300 meters). These targets range in age from Cenomanian to Campanian. They comprise four-way closures to stratigraphic channel traps. If a target matures into a prospect, the first well to drill one of these targets is anticipated to be spud post 2012.

DT Block

The following is a brief discussion of our prospects in the DT Block.

DT Sapele

DT Sapele is located in the eastern portion of the DT Block approximately 37 miles (60 kilometers) offshore Ghana in water depths of approximately 5,250 to 5,900 feet (1,600 to 1,800 meters). The target reservoir is a down-dip extension of the Upper Cretaceous Turonian age sand fairway at Jubilee. The combination structural stratigraphic reservoir is well defined with high resolution 3D seismic and well information from the surrounding Jubilee and Mahogany East discoveries. The first well to drill DT Sapele is expected to be spud in 2012.

Wawa

The Wawa prospect is located in the north central part of the DT block, approximately 21 miles (35 kilometers) offshore Ghana in water depths of approximately 650 to 3,350 feet (200 to 1,000 meters). The prospect has been defined with high resolution seismic data. The Wawa prospect comprises of Upper Cretaceous Campanian and Turonian reservoirs. The traps for the reservoirs within the prospect area are combination structural and stratigraphic traps. The well is anticipated to spud in 2012.

Tweneboa Deep (also known as Turonian Deep)

The Turonian Deep prospect is located in the southern central part of the DT block, approximately 33 miles (53 kilometers) offshore Ghana in water depths of approximately 4,400 to 6,450 feet (1,325 to 2,000 meters). The prospect has been defined by high resolution seismic data

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and consists of Turonian and Cenomanian sediments that are trapped stratigraphically within the reservoir fairway. The well is anticipated to spud in 2012.

Walnut

Walnut is located along the northern edge of the DT Block approximately 28 miles (45 kilometers) offshore Ghana in water depths of approximately 1,600 to 2,600 feet (500 to 800 meters). It targets stratigraphic and downthrown fault closures varying in age from Turonian to Campanian. The first well to drill Walnut is anticipated to be spud post 2012.

Wassa

Wassa is located in the south central portion of the DT Block approximately 44 miles (70 kilometers) offshore Ghana in water depths of approximately 5,900 to 6,200 feet (1,800 to 1,900 meters). It has a trapping geometry at multiple levels from Albian through Turonian with a stratigraphic trap element and a large three-way fault trap at the Albian level. The first well to drill Wassa is anticipated to be spud post 2012.

Adinkra

Adinkra is located along the northern edge of the DT Block approximately 28 miles (45 kilometers) offshore Ghana in water depths of approximately 1,600 to 2,600 feet (500 to 800 meters). It targets stratigraphic and downthrown fault closures varying in age from Turonian to Campanian. The first well to drill Adinkra is anticipated to be spud post 2012.

Oyoko

Oyoko is located along the northern edge of the DT Block approximately 28 miles (45 kilometers) offshore Ghana in water depths of approximately 1,600 to 2,600 feet (500 to 800 meters). It targets stratigraphic and downthrown fault closures of Albian to Cenomanian age. The first well to drill Oyoko is anticipated to be spud post 2012.

Ananta

Ananta is located in the western portion of the DT Block approximately 37 miles (60 kilometers) offshore Ghana in water depths of approximately 4,300 to 5,250 feet (1,300 to 1,600 meters). It is a stratigraphic trap of Campanian age located west of the existing Tweneboa wells. The Tweneboa-1 well encountered thick porous sands at this interval. Ananta contains similar facies as detected through AVO analysis. The first well to drill Ananta is anticipated to be spud post 2012.

Cameroon

During 2011, Kosmos had interests in two licenses in Cameroon, the Ndian River Block located in the Rio del Rey Basin, which we operate with a 100% participating interest, and the Perenco operated, Kombe-N'sepe Block located in the Douala Basin, in which Kosmos held a 35% interest. The Kombe-N'sepe license expired on December 31, 2011, as the Company did not exercise our option to extend the license period. The Ndian River Block is located in the eastern, onshore and shallow water offshore portion of the Rio del Rey Basin.

Kosmos is currently in the first of two available extensions of the exploration period of our Ndian River Block, which expires in November 2012. The current exploration period carries a one-well obligation and Kosmos is currently performing pre-drilling activities with plans to commence drilling in late 2012. The Ndian River petroleum contract provides for an extension of an exploration phase for a

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period of time that the Minister of Industry, Mines and Technology Development deems necessary to complete any exploration drilling in progress at the end of the exploration phase, with this extended period being at least six months. Current plans call for drilling activities to be in progress at the end of the current exploration phase and as such, we plan to apply for the extension in accordance with the petroleum contract and the regulations in force.

Cameroon sits in the Gulf of Guinea adjacent to and south of the Niger Delta. The coastal and offshore portions of Cameroon are associated with two major but different geological basins. In the north and adjacent to the Niger delta is the Rio del Rey Basin. In addition to the oil province, there is a large outboard natural gas condensate province containing the Alba field.

In January 2012, Kosmos entered into a license with Cameroon for the Fako Block. Kosmos is the operator and has a 100% participating interest in the block. The block covers 318,519 acres (1,289 square kilometers) and borders the southeast portion of our Ndian River Block in the Rio del Rey Basin. We have \$2.0 million in work commitments to perform exploration activities.

To date, Kosmos has acquired gravity, magnetic and 2D seismic data over selected portions of our Cameroon licenses. We have drilled two exploration wells which discovered hydrocarbons in sub-commercial quantities, which were subsequently plugged and abandoned in the Kombe-N'sepe Block.

Our Cameroon Prospects

The following is a brief discussion of our onshore Cameroon prospects on the Ndian River Block. We are currently assessing prospectivity on our recently acquired Fako Block license area, and accordingly information concerning prospects, if any, on such recently acquired license area is not yet available. We currently are, and plan to continue, acquiring seismic information to assess the prospectivity for this license area.

Sipo (formerly known as Liwenyi)

Sipo is located onshore, in the southern part of the Ndian River Block, within the Rio del Rey Basin. It is a large structurally trapped anticline associated with multiple stacked targets within the Miocene Isongo Formation. Sipo is located in the heart of the Isongo reservoir fairway which constitutes primary reservoir in the Alba and Esmeraldas fields in Equatorial Guinea and in Bowleven's recent IF and IE oil and natural gas condensate discoveries in the Etinde Block to the south. Sipo is also situated along trend from the Etinde Block discoveries and in a similar trap type. An exploration well is anticipated to be drilled late in 2012.

Liwenyi South

Liwenyi South is located onshore, in the southern part of the Ndian River Block, within the Rio del Rey Basin. It is a structurally trapped anticline associated with multiple stacked targets within the Miocene Isongo Formation. Liwenyi South is located in the next thrust sheet south from Sipo. It is located in the heart of the Isongo reservoir fairway, which constitutes primary reservoir in the Alba and Esmeraldas Fields in Equatorial Guinea and in the recent IF and IE oil and natural gas condensate discoveries in the Etinde Block to the south. Liwenyi South is also situated along trend from the Etinde Block discoveries and in a similar trap type. An exploration well is anticipated to be drilled post 2012.

Meme

Meme is located onshore, in the southern part of the Ndian River Block, within the Rio del Rey Basin. It is a faulted three-way closure trapped on the downthrown side of a

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three-way trapping fault and is comprised of several targets within the Miocene Isongo Formation. Meme is located along trend with the Alba and Esmeraldas Fields in Equatorial Guinea. An exploration well is scheduled to be drilled post 2012.

Bamusso

Bamusso is located onshore, in the southern part of the Ndian River Block, within the Rio del Rey Basin. It is a fault trap within the Upper Cretaceous section. An exploration well is anticipated to be drilled post 2012.

Morocco

During 2011, Kosmos pursued an acreage acquisition program offshore the Kingdom of Morocco and by year-end had acquired two new petroleum contracts, renewed an existing petroleum contract and acquired a new reconnaissance contract. Our exploration licenses include Cap Boujdour Offshore Block, which is within the Aaiun Basin, and Essaouira Offshore Block and Fom Assaka Offshore Block, which are within the Agadir Basin. Our reconnaissance contract is over the Tarhazoute Offshore area within the Agadir Basin.

Kosmos is the operator of the Cap Boujdour Offshore Block and has a 75% participating interest. This 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 multiple distinct exploration fairways on this block, each having independent play risks, providing substantial exploration opportunities. Based in part on a 3D seismic survey, we have been able to identify prospect inventory through trap identification, detailed structural analysis, and depositional history mapping. See "Item 1A. Risk Factors 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."

Kosmos is the operator of the Fom Assaka Offshore Block and has a 37.5% participating interest. Upon receipt of approval from the Moroccan government, we will acquire an additional 18.75% in the Fom Assaka Offshore Block from Pathfinder Hydrocarbon Ventures Ltd., one of our block partners. Kosmos is the operator of the Essaouira Offshore Block and has a 37.5% participating interest.

Kosmos is the operator and holder of a reconnaissance contract covering the Tarhazoute Offshore area and has a 100% interest. The Tarhazoute Offshore area is located offshore Morocco in the Agadir Basin between the Company's Essaouira and Fom Assaka Offshore Blocks. The reconnaissance contract has a one-year term, extendable for an additional six months, after which the Company has the right to enter into a petroleum contract for the acreage.

The Fom Assaka Offshore Block, Essaouira Offshore Block, and Tarhazoute Offshore area are located in the Agadir Basin. The Agadir Basin sediments comprise thick sequences of Lower to Upper Cretaceous sequences consisting of channels and lobes. A working petroleum system has been established in the basin based on onshore and shallow offshore wells.

In our new license areas, we have \$12.5 million, of which some was incurred in 2011, in work commitments to perform exploration activities. We are currently acquiring 3D seismic data on the Fom Assaka Offshore and Essaouira Offshore Blocks and may drill an exploratory well in Morocco as early as 2013.

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Our Moroccan Prospects

The following is a brief discussion of our prospects on the Cap Boujdour Offshore Block. We are currently assessing prospectivity on our recently acquired license areas in Morocco, and accordingly information concerning prospects, if any, on such recently acquired license areas is not yet available. We currently are, and plan to continue, acquiring seismic information to assess the prospectivity for these license areas.

Gargaa

Gargaa is located offshore in the southern part of the Cap Boujdour Offshore Block, within the Aaiun Basin, in water depths of approximately 5,250 to 6,500 feet (1,600 to 2,000 meters). It is one of four large four-way closures which sit on a 328 mile (100 kilometer) long anticline containing multiple stacked targets within the Early Cretaceous Valanginian through Hauterivian sections. 3D seismic data has been used to define its depositional and structural history. An exploration well is anticipated to be drilled post 2012.

Argane

Argane is located offshore, in the southern part of the Cap Boujdour Offshore Block, within the Aaiun Basin, in water depths of approximately 4,600 to 6,000 feet (1,400 meters to 1,800 meters). It is one of four large four-way closures which sit on a 328 mile (528 kilometers) long anticline containing multiple stacked targets within the Early Cretaceous Valanginian through Hauterivian sections. 3D seismic data has been used to define its depositional and structural history. An exploration well is anticipated to be drilled post 2012.

Safsaf

Safsaf is located offshore, in the southern part of the Cap Boujdour Offshore Block, within the Aaiun Basin, in water depths of approximately 8,200 to 9,500 feet (2,500 to 2,900 meters). It is a large four-way closure with a stratigraphic trapping element located over a anticline and containing multiple stacked targets within the Early Cretaceous Valanginian through Hauterivian sections. 3D seismic data has been used to define its depositional and structural history. An exploration well is anticipated to be drilled post 2012.

Aarar

Aarar is located offshore, in the southern part of the Cap Boujdour Offshore Block, within the Aaiun Basin, in water depths of approximately 6,500 to 8,500 feet (2,000 to 2,600 meters). It is one of four, large, four-way closures which sit on a 328 mile (528 kilometer) long compressional anticline containing multiple stacked targets within the Early Cretaceous Valanginian through Hauterivian sections. 2D seismic data has been used to define its depositional and structural history. An exploration well is anticipated to be drilled post 2012.

Zitoune

Zitoune is located offshore, in the southern part of the Cap Boujdour Offshore Block, within the Aaiun Basin, in water depths of approximately 6,250 to 7,500 feet (1,900 to 2,300 meters). It is one of four, large, four-way closures which sit on a 328 mile (528 kilometer) long anticline containing multiple stacked targets within the Early Cretaceous Valanginian through Hauterivian sections. 2D seismic data has been used to define its depositional and structural history. An exploration well is anticipated to be drilled post 2012.

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Al Arz

Al Arz is located offshore, in the southern part of the Cap Boujdour Offshore Block, within the Aaiun Basin, in water depths of approximately 1,300 to 2,000 feet (400 to 600 meters). It is a large, three-way fault closure on the upthrown side of a three-way trapping fault containing multiple stacked targets within the Early Cretaceous Hauterivian through Albian sections. 2D seismic data has been used to define its depositional and structural history. An exploration well is anticipated to be drilled post 2012.

Felline

Felline is located offshore, in the southern part of the Cap Boujdour Offshore Block, within the Aaiun Basin, in water depths of approximately 7,200 to 7,900 feet (2,200 to 2,400 meters). It is a large, four-way closure containing multiple stacked targets within the Early Cretaceous through Albian sections. 2D seismic data has been used to define its depositional and structural history. An exploration well is anticipated to be drilled post 2012.

Nakhil

Nakhil is located offshore, in the southern part of the Cap Boujdour Offshore Block, within the Aaiun Basin, in water depths of approximately 3,600 to 4,250 feet (1,100 to 1,300 meters). It is a large, four-way closure containing multiple stacked targets within the Early Cretaceous through Albian sections. 2D seismic data has been used to define its depositional and structural history. An exploration well is anticipated to be drilled post 2012.

Barremian Tilted Fault Block Play

An additional eight prospects have been defined on our existing 2D and 3D seismic database; these consist of a variety of three-way fault closures with targets in the Early Cretaceous age. Exploration wells are anticipated to be drilled post 2012.

Suriname

Kosmos' new ventures effort extended beyond our historical West Africa focus area as we entered into two petroleum contracts in South America. In December 2011, Kosmos entered into petroleum contracts covering Block 42 and Block 45 offshore Suriname. Kosmos is the operator and has a 100% participating interest in both blocks.

Our blocks in Suriname are located within the Guyana-Suriname Basin, along the Atlantic passive margin of northern South America. The 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. This basin has experienced the same geologic forces which occurred along the transform margin of Africa and, therefore, we believe the basin's petroleum system to be analogous to petroleum systems seen in West Africa. A petroleum system in Suriname has been proven by the presence of onshore producing fields.

In our new license areas, we have \$13.7 million in work commitments to perform exploration activities. We plan to acquire 3D seismic data in our blocks offshore Suriname in 2012 to further define prospectivity on the blocks.

Our Reserves

The following table sets forth summary information about our estimated proved reserves as of December 31, 2011. See "Item 8. Financial Statements and Supplementary Data Supplemental Oil and Gas Data (Unaudited)" for additional information.

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All of our estimated proved reserves as of December 31, 2011 were attributable to the Jubilee Field in Ghana.

Summary of Oil and Gas Reserves as of December 31, 2011

Reserves Category	Net Proved Reserves(1)		
	Oil, Condensate, NGLs (Mmbl)	Natural Gas(2) (Bcf)	Total (Mmboe)
	Proved developed	23	16
Proved undeveloped	25	8	26
	47	24	51

(1) Kosmos' unitized net interest is based on the 54.3666/45.6334% redetermination split, between the WCTP Block and DT Block. See "Item 1A. Risk Factors The unit partners' respective interests in the Jubilee Unit are subject to redetermination and our interests in such unit may decrease as a result." Totals within the table may not add due to rounding.

(2) These reserves represent only the quantities of fuel gas required to operate the FPSO during normal field operations. No natural gas volumes, outside of the fuel gas reported, have been classified as reserves. If and when a gas sales agreement is executed, a portion of the remaining gas may be reclassified as reserves. See "Item 1A. Risk Factors We may not be able to commercialize our interests in any natural gas produced from our license areas."

All of our proved undeveloped reserves ("PUDs") at December 31, 2011, 2010 and 2009, were associated with our Jubilee Field in Ghana.

Changes for the year ending December 31, 2011, include an increase of 8 Mmbl of proved undeveloped oil reserves due to the reclassification of some of the proved developed producing volumes to proved undeveloped for volumes related to the remediation efforts to mitigate the near wellbore productivity issues on certain of the producing wells in the Jubilee Field and an increase in our Jubilee Field unit interest. Additional changes include an increase of 4 Bcf in proved undeveloped gas reserves due to an increase in our Jubilee Field unit interest (see "Item 8. Financial Statements and Supplementary Data Note 4 Jubilee Field Unitization") and an increase in the estimated gas reserves to be used as fuel gas for operating the FPSO.

Changes for the year ending December 31, 2010, include a decrease of 35 Mmbl of proved undeveloped oil reserves, associated with reclassification to proved developed, resulting from first oil in the Jubilee Field on November 28, 2010. Additional changes include an increase of 4 Bcf, associated with the booking of gas reserves to be utilized as fuel gas for operating the FPSO.

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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, 2011.

	Projected Net Revenues (in Millions except \$/bbl)
Future net revenues	\$ 2,850
<i>Present value of future net revenues:</i>	
PV-10(1)	2,016
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)	2,016
Benchmark and differential oil price(\$/bbl)(3)	\$ 111.04

- (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 levied under the WCTP and DT PAs), using prices 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 or intermediate subsidiary level on future net revenues. However, it does include the effects of future tax expense levied at an asset level (in our case, it does include the effects of future Ghanaian tax expense levied under the WCTP and DT PAs). Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas assets. PV-10 should not be considered as an alternative to the Standardized Measure as computed under GAAP; however, we and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific corporate tax characteristics of such entities.
- (2) Standardized Measure represents the present value of estimated future cash inflows to be generated from the production of proved oil and natural gas reserves, net of future development and production costs, future income tax expense related to our proved oil and gas reserves levied at a corporate parent and intermediate subsidiary level, royalties, additional oil entitlements and future tax expense levied at an asset level (in our case, future Ghanaian tax expense levied under the WCTP and DT PAs), 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 and intermediate subsidiary level on future net revenues. However, as we had been a tax

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exempted company incorporated pursuant to the laws of the Cayman Islands and are now a tax exempted company incorporated pursuant to the laws of Bermuda pursuant to our corporate reorganization that was completed in our IPO in May 2011, and as the Company's intermediate subsidiaries positioned between it and the subsidiary that is a signatory to the WCTP and DT PAs will continue to be tax exempted companies, we have not been and do not expect to be subject to future income tax expense related to our proved oil and gas reserves levied at a corporate parent or intermediate subsidiary level on future net revenues. Therefore, the year-end 2011 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 \$111.02/bbl for Dated Brent at December 31, 2011. The price was adjusted for crude handling, transportation fees, quality, and a regional price differential. Based on the high quality of the crude, these adjustments are estimated to add a \$0.02/bbl premium relative to Dated Brent. This differential is utilized in our reserve estimates. The adjusted price utilized to derive the PV-10 is \$111.04/bbl.

Estimated proved reserves

Unless otherwise specifically identified in this report, the summary data with respect to our estimated proved reserves presented above has been prepared by Netherland, Sewell & Associates, Inc. ("NSAI"), our independent reserve engineering firm, 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 and adjusted for imbalances. 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, 2011 are based on costs in effect at December 31, 2011 and the 12-month unweighted arithmetic average of the first-day-of-the-month price for the fiscal year ending December 31, 2011, 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 that prices and costs will remain constant. See "Item 1A. Risk Factors 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."

Independent petroleum engineers

NSAI, our independent reserve engineers, 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.

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For the years ended December 31, 2011, 2010 and 2009, 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, 2011 and related future net revenues and PV-10 at December 31, 2011 are taken from reports prepared by NSAI, adjusted for imbalances, 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. The December 31, 2011 reserve report was completed on February 16, 2012, and a copy is included as an exhibit to this report.

In connection with the preparation of the December 31, 2011, 2010 and 2009 reserves reports, 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, 2011, based upon its evaluation. NSAI's primary economic assumptions in estimates included an ability to sell oil at a price of \$111.04/bbl, a certain level of capital expenditures necessary to complete the Jubilee Field development program and the exercise of GNPC's back-in right on the Jubilee Field development. The assumptions, data, methods and precedents were appropriate for the purpose served by these reports, and NSAI used all methods and procedures as it considered necessary under the circumstances to prepare the report.

Technology used to establish proved reserves

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

In order to establish reasonable certainty with respect to our estimated proved reserves, 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

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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 technical services team, we currently maintain an internal staff of eight petroleum engineering and geoscience professionals with significant international experience that contribute to our Reserve and Resource Reporting Process. This team works closely with NSAI to ensure the integrity, accuracy and timeliness of data furnished to NSAI in their reserve and resource estimation process. Our technical services team is responsible for overseeing the preparation of our reserves estimates. Our technical services team 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 Bachelor of Science degree in petroleum engineering. The NSAI technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Joseph J. Spellman and Mr. Daniel T. Walker. Mr. Spellman has been practicing consulting petroleum engineering at NSAI since 1989. Mr. Spellman is a Licensed Professional Engineer in the State of Texas (No. 73709) and has over 30 years of practical experience in petroleum engineering. He graduated from University of Wisconsin-Platteville in 1980 with a Bachelor of Science Degree in Civil Engineering. Mr. Walker has been practicing consulting petroleum geology at NSAI since 1993. Mr. Walker is a Licensed Professional Geoscientist in the State of Texas, Geology (No. 1272) and has over 30 years of practical experience in petroleum geoscience. He graduated from Michigan State University in 1980 with a Bachelor of Science Degree in Geology. Both technical principals meet or exceed 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; both are 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 reviews our Reserves and Resource Reporting Process on an annual basis. In addition, our technical 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 technical/operations management and senior technical staff review reserves and reserve estimates with representatives from our independent reserve engineers.

For the years ended December 31, 2011, 2010 and 2009, we engaged NSAI, independent petroleum engineers, to prepare independent estimates of the extent and value of the proved reserves associated with certain of our oil and gas properties. See " Independent petroleum engineers" above for further information regarding NSAI's report.

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License Areas

The following table sets forth certain information regarding the developed and undeveloped portions of our license areas as of December 31, 2011 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)						
<i>Ghana</i>						
Jubilee Unit	27.1	6.3			27.1	6.3
West Cape Three Points(2)			170.6	52.7	170.6	52.7
Deepwater Tano			190.1	34.2	190.1	34.2
<i>Cameroon(4)</i>						
Ndian River			434.2	434.2	434.2	434.2
<i>Morocco(3)</i>						
Cap Boujdour			7,349.1	5,511.8	7,349.1	5,511.8
Essaouira			2,898.7	1,087.0	2,898.7	1,087.0
Foum Assaka			1,599.5	599.8	1,599.5	599.8
<i>Suriname</i>						
Block 42			1,526.1	1,526.1	1,526.1	1,526.1
Block 45			1,266.7	1,266.7	1,266.7	1,266.7
Total	27.1	6.3	15,435.0	10,512.5	15,462.1	10,518.8

-
- (1) Net acreage based on Kosmos' working interest, before the exercise of any options or back-in rights. Our net acreage may be affected by any redetermination of interests in the Jubilee Unit. See "Item 1A. Risk Factors The unit partners' respective interests in the Jubilee Unit are subject to redetermination and our interests in such unit may decrease as a result."
- (2) The seven-year exploration phase of the WCTP PA expired on July 21, 2011. WCTP "Undeveloped Area" reflected in the table above represents acreage within the four discovery areas (Teak, Banda, Akasa and Mahogany East) that were not subject to relinquishment on the expiry of the exploration phase, WCTP Undeveloped Area reflected in the table above includes the development and production Area relating to the Mahogany East PoD, which is the subject of a Notice of Dispute with the Ministry of Energy and GNPC and is currently under discussion with the WCTP Block partners, GNPC and the Ministry of Energy (see " Our Ghanaian Discoveries WCTP Block Discoveries"). Additionally, the WCTP Undeveloped Area in the table above includes acreage within the area relating to the Cedrela prospect, that was to be drilled by the Cedrela-1 exploration well; but which is the subject of a Notice of Force Majeure and a Notice of Dispute with the Ministry of Energy and GNPC and is currently under discussion among the Company, GNPC and the Ministry of Energy.
- (3) Does not include the reconnaissance contract for the Tarhazoute area offshore the Kingdom of Morocco as we do not currently have a license for this area. This block covers 1,915,932 gross acres (7,754 square kilometers) and is located offshore in the Agadir Basin immediately between our Essaouira Offshore and Foum Assaka Offshore Blocks.
- (4) Does not include the petroleum contract for the Fako Block in Cameroon, which we entered into in January 2012. The block covers 318,519 acres (1,289 square kilometers) and borders the southeast portion of our Ndian River Block in the Rio del Rey Basin.

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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							
	Productive(2)		Dry(3)		Total		Productive(2)		Dry(3)		Total		Total Net	Total Gross
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net		
Year Ended														
December 31, 2011														
Ghana														
Jubilee Unit							1	0.24			1	0.24	0.24	1
West Cape Three Points			4	1.24	4	1.24							1.24	4
Deepwater Tano														
Cameroon														
Kombe-N'sepe			1	0.35	1	0.35							0.35	1
Total			5	1.59	5	1.59	1	0.24			1	0.24	1.83	6
Year Ended														
December 31, 2010														
Ghana														
Jubilee Unit							1	0.24			1	0.24	0.24	1
West Cape Three Points			1	0.31	1	0.31							0.31	1
Deepwater Tano			1	0.18	1	0.18							0.18	1
Cameroon														
Kombe-N'sepe			1	0.35	1	0.35							0.35	1
Total			3	0.84	3	0.84	1	0.24			1	0.24	1.08	4
Year Ended														
December 31, 2009														
Ghana														
Jubilee Unit							11	2.59			11	2.59	2.59	11
West Cape Three Points														
Deepwater Tano														
Total							11	2.59			11	2.59	2.59	11

- (1) As of December 31, 2011, 16 exploratory and appraisal wells have been excluded from the table until a determination is made if the wells have found proved reserves. These wells are shown as "Wells Suspended or Waiting on Completion" in the table below.
- (2) A productive well is an exploratory or development well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas 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, 2011:

Actively Drilling or Completing		Wells Suspended or Waiting on Completion	
Exploration	Development	Exploration	Development

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	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Ghana								
Jubilee Unit			1	0.24				
West Cape Three Points					8	2.47		
Deepwater Tano	2	0.36			8	1.44		
Total	2	0.36	1	0.24	16	3.91		

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Undeveloped license area expirations

The WCTP PA has a duration of 30 years from its effective date (July 2004); however, in July 2011, at the end of the seven-year exploration phase, the WCTP Relinquishment Area was subject to relinquishment. Our existing discoveries within the WCTP Block have not been relinquished, as the WCTP PA remains in effect after the end of the exploration phase and these are Akasa, Banda, Mahogany East and Teak. In addition, we have disputed the relinquishment of the area around the Cedrela prospect. In July 2011, immediately prior to Kosmos receiving the drilling rig from another operator, damage to the rig incurred during preparations to move the rig to the WCTP Block rendered the rig incapable of drilling the Cedrela-1 exploration well prior to the end of the WCTP exploration period on July 21, 2011. As a result of this unforeseen delay in the drilling of the Cedrela-1 exploration well, the Company, as Operator for the WCTP Block partners, delivered a Notice of Force Majeure. The Ministry of Energy and GNPC did not agree this event was Force Majeure. On August 24, 2011, we as Operator of the WCTP Block and on behalf of the WCTP PA Block partners, delivered a Notice of Dispute to the Ministry of Energy and GNPC as provided under the WCTP PA, which is the initial step in triggering the formal dispute resolution process under the WCTP PA with the Government regarding our rights to drill the Cedrela-1 exploration well. This Notice of Dispute establishes a process for negotiation and consultation for a period of 30 days (or longer if mutually agreed) among senior representatives from the Ministry of Energy, GNPC and the WCTP Block partners to resolve the matter. The issue continues to be discussed in an effort to reach a mutually agreed upon resolution among the parties. See "Item 1A. Risk Factors We 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."

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 exercised such right in July 2010 and formally submitted a proposed new petroleum agreement for the WCTP Relinquishment Area in early 2011. We and our WCTP Block partners, the Ghana Ministry of Energy and GNPC have agreed such WCTP PA rights extend from July 21, 2011 until such time as either a new petroleum agreement 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.

The Mahogany East area, a combined area covering parts of the Mahogany discovery and the Mahogany Deep discovery area was declared commercial in September 2010, and a PoD was submitted to Ghana's Ministry of Energy as of May 2, 2011. In a letter dated May 16, 2011, the Minister of Energy did not approve the PoD and requested that the WCTP Block partners take certain steps regarding notifications of discovery and commerciality; and requested other information. The WCTP Block partners believe the combined submission was proper and have held meetings with GNPC which resolved issues relating to the PoD work program. From May 2011, Ministry of Energy, GNPC and the WCTP Block partners continued working to resolve other differences; however, the WCTP PA contains specific timelines for PoD approval and discussions, which expired at the end of June 2011. On June 30, 2011, we as Operator of the WCTP Block and on behalf of the WCTP Block partners, delivered a Notice of Dispute to the Ministry of Energy and GNPC as provided under the WCTP PA, which is the initial step in triggering the formal dispute resolution process under the WCTP PA with the Government of Ghana regarding approval of the Mahogany East PoD. This Notice of Dispute establishes a process for negotiation and consultation for a period of 30 days (or longer if mutually agreed) among senior representatives from the Ministry of Energy, GNPC and the WCTP Block partners to resolve the matter. We and the WCTP Block partners are in discussions with the Ministry of Energy and GNPC to resolve differences on the PoD.

In the DT Block in Ghana, the first extension period of the exploration phase over the undeveloped acreage of the DT Block expired on January 19, 2011. In accordance with the DT PA, Tullow, on behalf of the DT Block partners, formally extended the DT PA into the second extension

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period and relinquished 25% of the DT Block. The seven-year exploration phase of the DT PA will expire in January 2013. Our existing discoveries within the DT Block are not subject to relinquishment upon expiration of the exploration phase of the DT PA, as the DT PA remains in effect after the end of the exploration phase, and these are Tweneboa, Enyenra and Ntomme. We and our DT Block partners have certain rights of first refusal for the granting of a new petroleum contract and certain rights to negotiate a new petroleum contract with respect to the DT Relinquishment Area. We and our DT Block partners exercised such right to negotiate a new petroleum contract in January 2012.

In Cameroon, under the Ndian River Production Sharing Contract and pursuant to a one-year extension approved by the Ministry of Industry, Mines, and Technological Development, the initial exploration phase to the Ndian River Block expired on November 19, 2010. On September 16, 2010, in compliance with the production sharing contract, we applied to Cameroon's Minister of Industry, Mines and Technology Development for a two-year renewal of the exploration period (the first of two additional exploration periods of two years each). On November 20, 2010, in accordance with the Ndian River Production Sharing Contract, Kosmos relinquished 30% of the original license area of the Ndian River Block and entered into the first two-year renewal period. In an order dated March 3, 2011, the Minister of Industry, Mines and Technology Development confirmed our entry into the first renewal period.

The Kombe-N'sepe License Agreements over the Kombe-N'sepe Block in Cameroon expired on December 31, 2011, after a previous six month extension was granted.

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 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. See "Item 1A. Risk Factors 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."

Significant Exploration Agreements

West Cape Three Points Block

Effective July 22, 2004, Kosmos, the EO Group and GNPC entered into the WCTP PA covering the WCTP Block offshore Ghana in the Tano Basin. Kosmos held an initial 86.5% working interest in the block. Pursuant to farm-out agreements for the WCTP Block dated September 1, 2006, Anadarko WCTP Company, Tullow and Sabre farmed into the WCTP Block. Subsequent to the initial farm-out agreements, Tullow acquired EO Group. As a result, Kosmos, Anadarko WCTP Company, Tullow and Sabre's participating interests are 30.875%, 30.875%, 26.396% and 1.854%, respectively. Kosmos is the operator. GNPC has a 10% participating interest and will be carried through the exploration and development phases. Under the WCTP PA, GNPC exercised its option in December 2008 to acquire an additional paying interest of 2.5% in the Jubilee Field development (see " Jubilee Field Unitization"). 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. Furthermore, it is obligated to pay 10% of the production costs of the Jubilee Field development, as 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 PA. Kosmos is required to pay a fixed royalty of 5% and a sliding-scale

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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 Block as originally awarded comprised approximately 483,599 acres (1,957 square kilometers). Due to contractual relinquishments at the commencement of contract periods, the WCTP Block currently comprises areas that are part of our existing discoveries in the WCTP Block, or approximately 182,417 acres (738 square kilometers) in water depths ranging from 165 to 5,900 feet (approximately 50 to 1,800 meters). The term of the WCTP PA is 30 years from the effective date of such agreement, being July 22, 2004. The initial exploration period of the block is three years, divided into two separate 18-month subperiods. In 2005, a 268,109 acre (1,085 square kilometers) 3D seismic survey was acquired, processed and interpreted by Kosmos. In 2006, Kosmos elected to proceed with the second subperiod with an exploration well commitment. The exploration well, Mahogany-1, was drilled and an oil discovery announced on June 18, 2007. The work and financial commitments were met for the initial exploration period. The next phase, the first extension period, commenced at the end of the initial exploration period and was for two years. The one exploration well commitment for this period was met by drilling the Odum-1 well, which tested a different prospect than the Mahogany-1 well. Odum-1 was announced as an oil discovery on February 25, 2008. In July 2009, Kosmos elected to enter the second and final two year extension period under the WCTP PA. The commitment for this period was met by drilling of the Dahoma-1 well, which tested a different prospect from those tested by Mahogany-1 and Odum-1. All work and financial obligations for the exploration periods under the WCTP PA have been met.

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 exercised such right in July 2010 and formally submitted a proposed new petroleum agreement for the WCTP Relinquishment Area in early 2011. We and our WCTP Block partners, the Ghana Ministry of Energy and GNPC have agreed such WCTP PA rights extend from July 21, 2011 until such time as either a new petroleum agreement 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 31, 2006, Kosmos, Tullow and Sabre entered into the DT PA with GNPC covering the DT Block offshore Ghana in the Tano Basin. Tullow is the operator with a 49.95% working interest. Sabre has a 4.05% working interest. Kosmos originally held a 36% working interest in the block; however, as a result of a farmout by Kosmos to Anadarko WCTP Company effective September 1, 2006, Kosmos and Anadarko WCTP Company each have an 18% participating interest in the block. GNPC has a 10% participating interest and will be carried through the exploration and development phases. Under the DT PA, GNPC exercised its option in January 2009 to acquire an additional paying interest of 5% in the commercial discovery with respect to the Jubilee Field 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, as 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 PA. 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.

The DT Block comprises approximately 203,345 acres (823 square kilometers). The term of the DT PA is 30 years from the effective date of such agreement, July 31, 2006. The initial exploration

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period is two and one-half years, divided into two subperiods. The first subperiod was for one year, and the contractor was obligated to reprocess 3D seismic data and acquire seabed logging. This commitment was met and the block partners entered the second subperiod. During the second subperiod of one and one-half years, the contractor was required to drill an exploration well, which was fulfilled by the drilling of the Tweneboa-1 exploration well. During December 2008, the block partners notified Ghana's Ministry of Energy of their intent to enter into the first extension period of two years commencing on January 19, 2009. During the first extension period of two years, the contractor was required to drill an exploration well, which was fulfilled by the drilling of the Owo-1 exploration well. During December 2010, the block partners notified Ghana's Ministry of Energy of their intent to enter into the second extension period of two years commencing on January 19, 2011. During the second extension period of two years, the contractor was required to drill an exploration well, which was fulfilled by the Onyina-1 exploration well, drilled during the first extension period. The DT PA provides that work performed in excess of that required to meet the obligations of an exploration period can be applied to obligations in a subsequent period and this was done. Also, the DT PA provides that if the contractor commits to the drilling of two or more wells during the second extension period, the mandatory acreage relinquishment is reduced from 50% to 25%. The contractor made this commitment in its notification of entry into the second extension period. Currently, the contractor must drill one additional exploration well prior to the end of the exploration period to fulfill the obligation, which is expected to be drilled in 2012.

The Ghanaian Petroleum Law and the WCTP and DT PAs form the basis of our exploration, development and production operations on these blocks. Pursuant to these petroleum agreements, 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. See "Item 1A. Risk Factors 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."

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 PAs and as required by Ghana's Ministry of Energy, it was agreed the Jubilee Field would be unitized for optimal resource recovery. In late February 2008, the contractors in the WCTP and DT Blocks agreed to an interim unit agreement (the "Pre Unit Agreement"). According to the Pre Unit Agreement, the initial Jubilee Field unit area, which boundary at the time was an approximation of the boundaries of the Jubilee Field, was deemed to consist of 35% of an area from the WCTP Block and 65% of an area from the DT Block. However, the tract participations were allocated 50% for the WCTP Block and 50% for the DT Block pending the results of the Mahogany-2 well. The Mahogany-2 well was announced as an oil discovery on May 5, 2008. Pursuant to the Pre Unit Agreement, the unit boundaries were modified to include the Mahogany-2 well and the tract participations remained 50% for each block.

Kosmos and its unit partners subsequently commenced development operations and negotiated a more comprehensive unit agreement, the UUOA, for the purpose of unitizing the Jubilee Field and governing each party's respective rights and duties in the Jubilee Unit. On July 13, 2009, Ghana's Ministry of Energy provided its written approval of the UUOA. The UUOA was executed by the unit partners and was effective as of July 16, 2009. Tullow is the Unit Operator, while Kosmos is the Technical Operator for Development of the Jubilee Unit. The Jubilee Unit holders' interests are subject to redetermination subject to the terms of the UUOA. See "Item 1A. Risk Factors The unit partners'

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respective interests in the Jubilee Unit are subject to redetermination and our interests in such unit may decrease as a result." The accounting for the Jubilee Unit is in accordance with the tract participation stated in the UUOA, adjusted for the initial redetermination process as discussed above. Although the Jubilee Field is unitized, Kosmos' working interests in each block outside the boundary of the Jubilee Unit remains the same. Kosmos remains operator of the WCTP Block outside the Jubilee Unit area. 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 54.36660% for the WCTP Block and 45.63340% for the DT Block. Our Unit Interest was increased from 23.50868% (our percentage after Tullow's acquisition of EO Group see "Item 8. Financial Statements and Supplementary Data Note 5 Joint Interest Billings") to 24.07710%.

We, as the Technical Operator, led the Integrated Project Team ("IPT"), which consisted of geoscience, engineering, commercial, project services, and operations disciplines from within the Jubilee Unit partnership. The Technical Operator evaluated the resource base and developed an optimized reservoir depletion plan. This plan included the design and placement of wells and the selection of topside and subsea facilities. The Technical Operator's responsibilities also extended to project management of the design and implementation of the complete field development system. The Unit Operator was responsible for drilling and completing the development wells for the Jubilee Field Phase 1 development, according to the specifications outlined by the IPT, and providing other in-country support. Upon first production, the Unit Operator assumed responsibility for the day-to-day operations and maintenance of the FPSO as well as overseeing and optimizing the reservoir management plan based on field performance, including any well workover activity or additional infill drilling. The responsibility of the Technical Operator and the IPT for the Jubilee Field Phase 1 development was completed upon commissioning of the gas compression and injection systems and project administrative close out.

On July 13, 2009, Ghana's Ministry of Energy provided its written approval of the Jubilee Phase 1 PoD. First oil from the Jubilee Field Phase 1 development commenced on November 28, 2010, and we received approval from Ghana's Ministry of Energy for the Jubilee Field Phase 1A development in January 2012. We intend to submit a Jubilee Full Field development plan in late 2013.

Ndian River Block

On December 19, 2006, Kosmos signed the Ndian River Production Sharing Contract covering the Ndian River Block located predominately onshore Cameroon. Kosmos has a 100% participating interest in the block and is the operator. Société Nationale des Hydrocarbures ("SNH") will be carried through the exploration and appraisal phases and has the option to back into the contract with an interest of up to 15% upon approval of a PoD. The Ndian River Production Sharing Contract provides for Kosmos to recover its share of expenses incurred ("cost recovery oil") and its share of remaining oil ("profit oil"). Cost recovery oil is apportioned to Kosmos from up to 60% of gross revenue prior to profit oil being split between the government of Cameroon 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 40% is applied to profits. The initial period of the exploration phase is three years and there are two renewal periods of two years with each carrying a one-well obligation. The Ndian River Block comprises approximately 434,163 acres (approximately 1,757 square kilometers) and occupies a coastal strip of the Rio del Rey Basin in northwestern Cameroon. The block is located about 62 miles (100 kilometers) west-northwest of the city of Douala and extends to the Cameroon/Nigeria border. The license commitment requires us to conduct a 2D seismic survey (subject to a \$5.5 million maximum spend commitment) as part of the multi-year exploration and exploitation agreement. Because of delays caused by difficulties in conducting seismic operations during the rainy season, the survey commenced in November 2009, causing a portion of the survey to be acquired beyond the initial exploration phase end date of November 19, 2009. In

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recognition of this, we, in consultation with SNH and Cameroon's Ministry of Industry, Mines and Technology Development, agreed to a process for receiving an extension to the initial period. On November 16, 2009, we received Ministry approval of a one year extension to the initial period of the exploration phase, which ended on November 19, 2010. A 2D seismic survey of 52 miles (85 kilometers) has been acquired in the block and interpretation of the survey is ongoing. On September 16, 2010, in accordance with the terms of the Ndian River Production Sharing Contract and after fulfillment of all the obligations of the initial period, we submitted an application for entry into the first of two renewal periods of the exploration phase with an attendant one-well obligation. We plan to drill a well on the Ndian River Block in late 2012. Planning for this well is ongoing.

Sales and Marketing

Production from the Jubilee Field began on November 28, 2010, and we received our first oil revenues in early 2011. As provided under the UUOA and the WCTP and DT PAs, we are entitled to lift and sell our share of the Jubilee production in conjunction with the Jubilee Unit partners. We have entered an agreement with an oil marketing agent to market our share of the Jubilee Field oil on the international spot market, and we approve the terms of each sale proposed by such agent. Oil from the Jubilee Field has generally sold at a premium to Dated Brent. 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 readily available, we believe that the loss of our marketing agent and/or any of the purchasers identified by our marketing agent would not have a long-term material adverse effect on our financial position or results of 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 personnel compliments 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 unsuccessful wells, sustained periods of volatility in financial and commodities 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 may adversely affect our competitive position.

We are also 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, and can lead to shortages of, and increasing costs for, drilling equipment, services and personnel. In recent years, oil and natural gas companies have experienced higher drilling and operating costs. Shortages of, or increasing costs for, experienced drilling crews and equipment and services could restrict our ability to drill wells and conduct our operations.

Competition is also strong for attractive oil and natural gas producing assets, undeveloped license areas and drilling rights, and we cannot assure holders of our common shares that we will be able to successfully compete when attempting to make further strategic acquisitions.

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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. For examples, see "Item 1A. Risk Factors 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" and "Item 1A. Risk Factors Maritime boundary demarcation between Côte D'Ivoire and Ghana may affect a portion of our license areas." and "Item 1. Business Operations by Geographic Area, Ghana."

Environmental Matters

General

We and our operations 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 commences;

enjoin some or all of the operations of facilities deemed not in compliance with permits;

restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling, production and transportation activities;

limit or prohibit drilling activities in certain locations lying within protected or otherwise sensitive areas; and

require remedial measures to mitigate or remediate pollution 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 are enacted or other governmental action is taken that prohibits or restricts offshore drilling or imposes environmental requirements that result in increased costs to the oil and gas industry in general, such as more stringent or costly waste handling, disposal, cleanup requirements or financial responsibility and assurance requirements.

For example, the Macondo spill in the Gulf of Mexico (described in "Item 1A. Risk Factors Participants in the oil and gas industry are subject to numerous laws that can affect the cost, manner or feasibility of doing business") has resulted and will likely continue to result in increased scrutiny and

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regulation 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 or prevent our operations in those countries.

Climate Change

Our operations and the combustion of petroleum and natural-gas based products results in the emissions of greenhouse gases ("GHGs") that could contribute to global climate change. Climate change regulation has gained some momentum in recent years internationally and at the federal, regional, state and local levels in the United States. On the international front, various nations, including countries in which we have petroleum contracts, have committed to reducing their GHG emissions pursuant to the Kyoto Protocol, which is set to expire in 2012. Passage of a successor international agreement or scheme aimed at the reduction of GHGs is uncertain.

In December 2009, an international meeting was held in Copenhagen, Denmark to further progress towards a new international treaty or agreement regarding GHG emissions reductions after 2012. A number of countries, including countries in which we have petroleum contracts, entered into the Copenhagen Accord, which represents a broad political consensus that reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and contains non-binding emissions reductions targets. Further discussions towards an agreement took place in Cancun, Mexico at the end of 2010 and Durban, South Africa in December 2011. The Durban conference resulted in, among other things, an agreement to negotiate a new climate change regime by 2015 that would aim to cover all major GHG emitters worldwide, and take effect by 2020. In addition, the Durban conference resulted in the relevant parties agreeing to extend the Kyoto Protocol for a second commitment period. Any treaty or other arrangement ultimately adopted by any of the countries in which we have operations or otherwise do business may increase our compliance costs, such as for monitoring or reducing emissions, and may have an adverse impact on the global supply and demand for oil and natural gas, which could have a material adverse impact on our business or results of operations.

Furthermore, the physical effects of climate change could have an adverse effect on our operations through increased severity and frequency of weather events, including storms, floods and other events, which could increase costs to repair and maintain our facilities or delay or prevent our operations. If such effects were to occur, they could have an adverse effect on our exploration and production operations, or disrupt transportation or other process-related services provided by our third party contractors.

Oil Spill Response

Kosmos has developed and adopted an Oil Spill Contingency Plan ("OSCP") for the coordination of responses to oil spills arising from its operations in Ghana, including the WCTP Block. In addition, Tullow 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 Kosmos. A Tier 2 spill is a larger incident 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 OSCP, 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. Approximately 130 personnel (composed primarily of Tullow and Kosmos employees, Ghanaian Navy personnel and local contractors) have been trained on the assembly and operation of Tier 1 and Tier 2 onshore, nearshore and harbor response equipment. In the case of a Tier 3 incident, we engage the services of Oil Spill Response Limited ("OSRL") of Southampton, United Kingdom, an oil spill response contractor.

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Our associate membership with OSRL entitles us to utilize its oil spill response services comprising technical expertise and assistance, including access to response equipment and dispersant spraying systems. Kosmos does not own any oil spill response equipment. Instead, Kosmos and Tullow each maintain separate 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 rapid 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 quick mobilization.

As Unit Operator for the Jubilee Field, 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 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, fully loaded with dispersant, of six hours. Additional stockpiles of dispersant are maintained in Takoradi.

In the case of a Tier 3 event, our associate membership in OSRL provides us with access to the large stockpile of equipment in Southampton, United Kingdom along with access to additional dispersant spraying aircraft. Kosmos could hire additional resources such as boats, earth moving equipment and personnel as necessary to respond to such an event. While we have the above in place, we can make no assurance, that these resources will be available or timely respond as intended, perform as designed or be able to fully contain or cap any oil spill, blow-out or uncontrolled flow of hydrocarbons.

Per common industry practice, under the agreements currently in place governing the terms of use of the drilling rigs used 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 working 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. Kosmos maintains insurance coverage for an incident concerning a well that results in pollution and environmental damage. The amount of annual insurance coverage maintained is proportional to our interest in a given well; with our current annual well control coverage for Ghana being \$300 million per incident multiplied by our working interest in a well for well control, re-drilling, pollution, clean up and containment, excess of retention of \$5 million multiplied by our working interest. In addition we maintain annual third party liability coverage of \$300 million multiplied by our working interest in a well for third party liabilities including pollution coverage, environmental damages liabilities and/or claims made by or on behalf of third party individuals in the event of such party's bodily injury, death or property damage. For example, if there were a well blowout in the Jubilee Field (in which we have a 26.85484% development working interest) our limit of well control, redrill and pollution clean up and containment coverage would be 26.85484% of \$300 million (being \$80.6 million) excess of retention of 26.85484% of \$5 million (being \$1.3 million), and our limit of liability coverage including pollution liability would be 26.85484% of \$300 million (being \$80.6 million).

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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 partnership with local or foreign partners. Companies who wish to gain rights to explore and produce in Ghana can only do so by entering into a petroleum agreement with 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 Energy represents the state in its regulatory capacity. GNPC has rights to undertake petroleum operations in any acreage declared open by Ghana's Ministry of Energy and has a carried interest in each petroleum agreement and is typically increased by a certain agreed upon amount at the option of GNPC following the declaration of any commercial discovery. 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 Energy. The 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 Energy. 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 new Petroleum Revenue Management Act and the Petroleum Commission Act 2011. The new 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 creates 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 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 anticipate a period of transition as the Petroleum Commission becomes active. 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 PAs (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. See "Item 1A. Risk Factors Participants in the oil and gas industry are subject to numerous laws that can affect the cost, manner or feasibility of doing business."

Cameroon

In 1999/2000, the government of Cameroon approved the Petroleum Code (the "Cameroon Petroleum Code") and Petroleum Regulations that were designed to rationalize regulation of the upstream local oil and gas industry. The Cameroon Petroleum Code applies to all license awards granted post 2000. Arrangements entered into prior to 2000 are grandfathered under the former law. Companies who wish to gain rights to explore and produce in Cameroon can only do so by entering

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into a petroleum contract with Cameroon, represented by SNH, the Cameroon national oil company, and assignments of such contracts require the consent of the government. SNH, established in March 1980, participates in the form of joint ventures with the "contractors." Assignment of license interests requires the consent of SNH.

Morocco

The two main legislative acts in Morocco relevant to petroleum exploration and production are (i) the Law 21-90 (1 April 1992) as amended and completed by the Law 27-99 (15 February 2000) and (ii) the Decree 2-93-786 (3 November 1993) as amended and completed by decree 2-99-210 (16 March 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 his behalf is the *Office National des Hydrocarbures et des Mines* generally referred to as "ONHYM." ONHYM is a public establishment (*établissement public*) with the legal personality and financial autonomy created pursuant to the Law 33-01 (11 November 2003) which was further completed by the Decree 2-04-372 (29 December 2004).

Pursuant to the Law 21-90, it is provided that the granting of an exploration permit is subject to the conclusion of a petroleum agreement 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 percentage interests in field developments 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 license issued to Kosmos. See "Item 1A. Risk Factors 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."

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 Maatschappij Suriname N.V. ("Staatsolie") was founded in 1980 as a state enterprise and holds mining rights onshore and offshore in Suriname. The 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 petroleum 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.

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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, 2011, we had approximately 190 employees. None of these employees is 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 on March 5, 2004. Pursuant to the terms of a corporate reorganization that was completed simultaneously with the closing of our IPO, 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. Our web site is www.kosmosenergy.com.

Available Information

Kosmos is listed on the NYSE and is traded under the symbol "KOS". We file or furnish annual, quarterly and current reports, proxy statements and other information with the SEC. The 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 reasonable 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. The majority of our oil and natural gas portfolio 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. Most of our current discoveries and 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 designate a discovery as "commercial," 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 exploration, appraisal and development efforts, has only recently been considered potentially 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 onshore Cameroon and deepwater offshore Morocco and Suriname prospects have not yet proved to be economically viable production areas, as to date we do not have a commercially viable discovery or production in either of these regions. 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, including with regard to size and quality, 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,

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discoveries or producing fields may not prove to be accurate indicators of the success of developing proved reserves from our discoveries and prospects. Furthermore, we have no way of evaluating the accuracy of the data from analog wells or prospects produced by other parties which we may use.

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

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

Exploring for and developing hydrocarbon reserves involves a high degree of 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. A variety of factors, including geologic and market-related, can cause a field to become uneconomic or only marginally economic. 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. The successful drilling of a single well may not be indicative of the potential for the development of a commercially viable field. In Africa and South America, 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.

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.

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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.

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 report 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 licenses over such areas may fluctuate and may increase significantly since the original term, and we may not be able to renew or extend such licenses 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.

Regarding our licenses in Ghana, the WCTP PA extends for a period of 30 years from its effective date (July 2004); however, in July 2011, the WCTP Relinquishment Area was subject to relinquishment. We and our WCTP Block partners have certain rights to negotiate a new petroleum contract with respect to the WCTP Relinquishment Area. In July 2010, we and our WCTP Block partners exercised our right to negotiate a new petroleum contract and formally submitted a proposed new petroleum agreement for the WCTP Relinquishment Area in early 2011. If we are unsuccessful in negotiating a new petroleum agreement or choose to not match a bona fide third party offer for the WCTP Relinquishment Area, the identified prospects within the WCTP Block will not be able to be drilled by us. Further, if we are able to negotiate a new petroleum agreement or match a bona fide third party offer, we cannot assure you that any such new agreement will either be entered into or be on the same terms as the current WCTP PA.

The DT PA also extends for a period of 30 years from its effective date and contains similar relinquishment provisions to the WCTP PA, but with the end of the seven year exploration phase occurring in January 2013. We and our DT Block partners have certain rights of first refusal for the granting of a new petroleum agreement with respect to the DT Relinquishment Area. We exercised such right in June 2011. If we are unable to negotiate a new petroleum agreement or we choose to not match a bona fide third party offer for the DT Relinquishment Area, the identified prospects within the DT PA Block will not be able to be drilled by us. Further, if we are able to negotiate a new petroleum agreement or match a bona fide third party offer, we cannot assure you that any such new agreement will either be entered into or be on the same terms as the current DT PA.

Regarding our license in Cameroon, the exploration period for the Ndian River license will expire on November 20, 2012. Kosmos is required to drill one well before the expiration of this renewal period. Failure to do so may result in our loss of the license. Regarding our recently acquired petroleum contract in Cameroon, the Fako Block, the initial exploration period will expire on January 13, 2014. Under this petroleum contract, we have work commitments to perform exploration activities and other related activities totaling \$2.1 million. Failure to do so may result in our loss of the license.

Regarding our licenses in Suriname, under the production sharing contract covering Block 42, effective December 13, 2011, Kosmos is obligated during the initial four year exploration phase to conduct certain studies, reprocess existing 2D seismic; acquire, process and interpret 1,400 kilometers of 2D seismic; and acquire, process and interpret 500 square kilometers of 3D seismic. Under the production sharing contract covering Block 45, effective December 13, 2011, Kosmos is obligated during the initial three year exploration phase to conduct certain studies; reprocess existing 2D seismic;

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and acquire, process and interpret 1,000 kilometers of 3D seismic. Failure to complete such requirements may result in our loss of these licenses.

We are currently in the initial exploration phase for our petroleum contracts in Morocco. The Cap Boujdour Offshore Block, Essaouira Offshore Block, and the Fom Assaka Offshore Block expire on March 1, 2013, April 21, 2014, and January 1, 2014, respectively. Under these petroleum contracts, we have work commitments to perform exploration activities and other related activities totaling \$12.5 million. Failure to do so may result in our loss of the license.

For each of our license areas, 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 licenses, please see "Item 1. Business Our Geographic Areas of Operation."

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.

Our principal exposure to credit risk will be through receivables resulting from the sale of our oil, which we plan to market to energy marketing companies and refineries, and to cover our commodity derivatives contracts. The inability or failure of our significant customers or counter-parties 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.

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 54.36660% for the WCTP Block and 45.63340% for the DT Block. Our Unit Interest (participating interest in the Jubilee Unit) was increased from 23.50868% (our percentage after Tullow's acquisition of EO Group's interest in July 2011) to 24.07710%. A second redetermination could occur sometime after December 31, 2013, if requested by a party that holds greater than a 10% interest in the unit. We cannot assure you that any redetermination pursuant to the

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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 Field 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 Field 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 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;

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.

We have been, until recently, a development stage entity and our future performance is uncertain.

We were a development stage entity until we first generated revenue in early 2011. Development stage entities face substantial business risks and may suffer significant losses. Until recently, we have generated substantial net losses and negative cash flows from operating activities since our inception and may continue to incur substantial net losses as we continue our exploration and appraisal program. We face challenges and uncertainties in financial planning as a result of the limited amount of historical data and uncertainties regarding the nature, scope and results of our future activities. As a new public company, we will need to develop additional business relationships, establish additional operating procedures, hire additional staff, and take other measures necessary to conduct our intended business activities. We may not be successful in implementing our business strategies or in completing the development of the facilities necessary to conduct our business as planned. In the event that one or more of our drilling programs is not completed, is delayed or terminated, our operating results will be adversely affected and our operations will differ materially from the activities described in this report.

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There are uncertainties surrounding our future business operations which must be navigated, some of which may cause a material adverse effect on our results of operations and financial condition.

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 PV-10 and Standardized Measure of discounted future net revenues (as defined herein) as of December 31, 2011.

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 anticipated market premium, without giving effect to derivative transactions. Actual future net revenues from our oil and natural gas assets will be affected by factors such as:

actual prices we receive for oil and natural gas;

actual cost of development and production expenditures;

derivative transactions;

the amount and timing of actual production; and

changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas assets will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

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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, then the present value of our net revenues at a 10% discount rate ("PV-10") and the Standardized Measure as of December 31, 2011 would each decrease by approximately \$19.7 million. 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 have 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 effected. 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 expect that we will need to raise substantial additional capital, through additional debt financing, strategic alliances or future private or public equity offerings.

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;

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

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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 such term for 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."

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. 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 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 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.

Lower oil prices may not only decrease our revenues on a per share basis but also may reduce 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.

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If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas assets, and such decreases could result in reduced availability under our commercial debt facility.

We will review our proved oil and natural gas assets for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. 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, 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.

In addition, our bank borrowing base is subject to periodic redeterminations. We could be forced to repay a portion of our bank borrowings due to redeterminations of our borrowing base. Redeterminations may occur as a result of a variety of factors, including the 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.

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 has announced it will build a gas pipeline from the Jubilee Field to transport such natural gas to the mainland for processing and sale; however, to date, the planning and execution of such pipeline is in its early stages. Even if such pipeline is constructed, it would only give us access to a limited natural gas market. In addition, in connection with the approval of the Jubilee Phase 1 PoD, we granted the first 200 Bcf of natural gas produced from the Jubilee Field Phase 1 development to

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Ghana at no cost. The Jubilee Phase 1 PoD provided an initial period during commencement of production for which natural gas could be flared. Subsequent to such period, the Jubilee Phase 1 PoD provided that a portion of the natural gas would be reinjected and the balance of the natural gas would be transported to shore via the pipeline to be built. While reinjection improves the recoverability of oil from such reservoirs in the short term, in order to maintain maximum oil production levels, eventually we will need to either flare excess natural gas or otherwise remove it from the reservoirs' production system. We have not been issued a permit from the Ghana Environmental Protection Agency ("Ghana EPA") to flare natural gas produced from the Jubilee Field in the long-term. In the absence of construction of a natural gas pipeline or if we do not receive a permit to flare such natural gas for the long-term prior to reaching the Jubilee Field Phase 1's reinjection capacity, the field's oil production capacity may be adversely affected.

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, 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, environmental protection and climate change). The effect of these factors, individually or jointly, may result in us not receiving an adequate return on invested capital.

In the event that our currently undeveloped discoveries and prospects are developed and become operational, they may not produce oil and natural gas in commercial quantities or at the costs anticipated, and our projects may cease production, in part or entirely, in certain circumstances. Discoveries may become uneconomic as a result of an increase in operating costs to produce oil and natural gas. Our actual operating costs 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 environmental 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;

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uncontrolled flows or leaks of oil, well fluids, natural gas, brine, toxic gas or other pollution;

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 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, 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. 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 significant liabilities, cost overruns or delays. 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 and South America may never be economically producible.

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We 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.

All of our proved reserves and our discovered fields are located offshore Ghana. The WCTP PA and the DT PA cover the two blocks that form the basis of our exploration, development and production operations in Ghana. Pursuant to these petroleum agreements, most significant decisions, including our plans for development and annual work programs, must be approved by GNPC and/or Ghana's Ministry of Energy. We have previously had disagreements with the Ministry of Energy and GNPC regarding certain of our rights and responsibilities under these petroleum agreements, the Petroleum Law of 1984 (PNDCL 84) (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 and assertions that could be read to give rise to taxes payable under the Ghanaian Tax Law in connection with our IPO. These past disagreements have been resolved. In connection with resolving certain of these disagreements, we entered into a settlement agreement with GNPC and the Government of Ghana in December 2010. As part of such agreement and with respect to one particular issue, we agreed to pay GNPC \$8 million upon signing the settlement agreement and \$15 million upon the first to occur of certain liquidity events, including the successful completion of our IPO.

We issued a Notice of Dispute to the Ministry of Energy and GNPC regarding our right to force majeure protection from an event of Force Majeure that occurred as we were preparing to drill the Cedrela-1 exploration well on the WCTP Block. We continue to discuss this issue so that we may reach an agreement with the Ministry of Energy and GNPC such that we may drill the Cedrela-1 exploration well in 2012. If this dispute is not resolved in our favor, the Cedrela exploration area will become part of the WCTP Relinquishment Area and will be subject to our right to negotiate a new petroleum agreement with respect to the undeveloped parts of the WCTP Block, unless we and our WCTP Block partners do not wish to match any bona fide third party offer received by GNPC; however, we cannot assure you that any such new petroleum agreement will either be entered into or be on the same terms as the current WCTP PA. We also issued a Notice of Dispute to the Ministry of Energy and GNPC regarding the lack of approval of the Mahogany East PoD. We continue to discuss resolution of the PoD with the Ministry of Energy and GNPC.

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.

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

Our current exploration licenses are located in Africa and South America. Some or all of these licenses could be affected should either region experience any of the following factors (among others):

severe weather or natural disasters or other 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; and/or

military conflicts or civil unrest.

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For example, oil and natural gas operations in our license areas 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 our activities.

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

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

Some countries in the geographic areas where we operate have experienced political instability in the past or are currently experiencing instability. Disruptions may occur in the future, and losses caused by these disruptions may occur that will not be covered by insurance. Consequently, our offshore 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 Ghana, Cameroon, Morocco, Suriname, 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.

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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.

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), the dispute remains stalemated. It is uncertain when and how Western Sahara's sovereignty issues will be resolved.

We own a 75% working interest in the Cap Boujdour Offshore Block located geographically offshore Western Sahara. Our licenses were 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 material adverse effect on our results of operations and financial condition.

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

In early 2010, Ghana's western neighbor, the Republic of 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 in order to determine Ghana's land and maritime boundaries. Ghana has opted out of compulsory dispute settlement under the United Nations Convention on the Law of the Sea. As such we expect that this matter will likely be resolved via bilateral discussions between the Governments. We understand that such discussions are continuing, although the status and results of these discussions have not been announced and the issue remains unresolved at present. The Ghanaian-Ivorian maritime boundary forms the western boundary of the DT Block offshore Ghana. In September, 2011, the Ivorian Government issued a map reflecting potential petroleum license areas that overlap with the DT Block, although no conflicting licenses have been awarded. Uncertainty remains with regard to the outcome of the boundary demarcation between Ghana and Côte d'Ivoire and we do not know if the maritime boundary will change, therefore affecting our rights to explore and develop our discoveries or prospects within such areas.

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

The international oil and gas industry, including Africa and South America, 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 drill attempts, 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 and obligations, including remediation or investigation activities.

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 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 recently 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 PAs 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."

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Furthermore, the Macondo incident in the Gulf of Mexico may have increased certain of the risks faced by those drilling for oil in deepwater regions, including, without limitation, the following:

increased industry standards, governmental regulation and enforcement of our and our industry's operations in a number of areas, including health and safety, financial responsibility, environmental, licensing, taxation, equipment specifications and training requirements;

increased difficulty or delays in obtaining rights to drill wells in deepwater regions;

higher operating costs;

higher insurance costs and increased potential liability thresholds under environmental laws;

decreased access to appropriate equipment, personnel and infrastructure in a timely manner;

higher capital costs as a result of any increase to the risks we or our industry face; and

less favorable investor perception of the risk-adjusted benefits of deepwater offshore drilling.

The occurrence of any of these factors, or the continuation thereof, could have a material adverse effect on our business, financial position or future results of operations.

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

We and our operations 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 and transportation of regulated materials and the health and safety of our employees. We are required to obtain environmental permits from governmental authorities for our operations, including drilling permits for our wells. We have not been or may not be at all times in complete compliance with these permits and the environmental laws and regulations to which we are subject, and there is a risk that these laws and regulations could change in the future or become more stringent. If we violate or fail to comply with these laws, regulations or permits, 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 permits in a timely manner or at all (due to opposition from partners, community or environmental interest groups, governmental delays or any 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 permits or such changes in or enactment of laws 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 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 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 and 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 the acts or omissions of our contractors, 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 claims that might arise from our operations or at any of our license areas. If a significant accident or

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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 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 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. Various countries and regions have agreed to regulate emissions of GHGs, including methane (a primary component of natural gas) and carbon dioxide (a byproduct of oil and natural gas combustion). The regulation of GHGs and the physical impacts of climate change in the areas in which we, our customers and the end-users of our products operate could adversely impact our operations and the demand for our products.

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, or exposure to, regulated substances may adversely affect our results of operations and financial condition. See "Item 1. Business Environmental Matters."

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

We are subject to the U.S. Foreign Corrupt Practices Act ("FCPA") and other laws that prohibit improper payments or offers of payments to foreign government officials and political parties for the purpose of obtaining or retaining business or otherwise securing an improper business advantage. In addition, the United Kingdom has enacted the Bribery Act of 2011, and we may be subject to that legislation under certain circumstances. We do business and may do additional business in the future in countries and regions in which we may face, directly or indirectly, corrupt demands by officials. We face the risk of unauthorized payments or offers of payments by one of our employees or consultants. Our existing safeguards and any future improvements may prove to be less than effective in preventing such unauthorized payments, and our employees and consultants may engage in conduct for which we might be held responsible. Violations of the FCPA may result in severe criminal or civil sanctions, and we may be subject to other liabilities, which could negatively affect our business, operating results and financial condition. In addition, the U.S. government may seek to hold us liable for successor liability FCPA violations committed by companies in which we invest or that we acquire.

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

We intend to maintain insurance against certain risks in the operation of the business we plan to develop and in amounts in which we believe to be reasonable. Such insurance, however, may contain exclusions and limitations on coverage. For example, we are not insured against political or terrorism risks. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition and results of operations.

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

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

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

production is less than the volume covered by the derivative instruments;

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

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

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

Our commercial debt facility contains certain covenants that may inhibit our ability to make certain investments, incur additional indebtedness and engage in certain other transactions, which could adversely affect our ability to meet our future goals.

Our commercial debt facility includes certain covenants that, among other things, restrict:

our investments, loans and advances and certain of our subsidiaries' payment of dividends and other restricted payments;

our incurrence of additional indebtedness;

the granting of liens, other than liens created pursuant to the commercial debt facility and certain permitted liens;

mergers, consolidations and sales of all or a substantial part of our business or licenses;

the hedging, forward sale or swap of our production of crude oil or natural gas or other commodities;

the sale of assets (other than production sold in the ordinary course of business); and

our capital expenditures that we can fund with our commercial debt facility.

Our commercial debt facility requires us to maintain certain financial ratios, such as debt service coverage ratios. All of these restrictive covenants may limit our ability to expand or pursue our business strategies. Our ability to comply with these and other provisions of our commercial debt facility may be impacted by changes in economic or business conditions, our results of operations or events beyond our control. The breach of any of these covenants could result in a default under our commercial debt facility, in which case, depending on the actions taken by the lenders thereunder or their successors or assignees, such lenders could elect to declare all amounts borrowed under our commercial debt facility, together with accrued interest, to be due and payable. If we were unable to repay such borrowings or interest, our lenders, successors or assignees could proceed against their collateral. If the indebtedness

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under our commercial debt facility were to be accelerated, our assets may not be sufficient to repay in full such indebtedness.

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

In March 2011 we entered into a \$2.0 billion commercial debt facility (the "Facility"), which may be increased to \$3.0 billion upon our obtaining additional commitments. At December 31, 2011, we had \$1.1 billion outstanding and \$890 million of committed undrawn capacity under such facility, of which \$153 million was available. In the future, we may incur significant indebtedness in order to make investments or acquisitions or to explore, appraise or develop our oil and natural gas assets.

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

a significant portion or all of our cash flows, when generated, could be used to service our indebtedness;

a high level of indebtedness could increase our vulnerability to general adverse economic and industry conditions;

the covenants contained in the agreements governing our outstanding indebtedness will limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments;

a high level of indebtedness may place us at a competitive disadvantage compared to our competitors that are less leveraged and therefore, may be able to take advantage of opportunities that our indebtedness could prevent us from pursuing;

our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;

additional hedging instruments may be required as a result of our indebtedness;

a high level of indebtedness may make it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then-outstanding bank borrowings; and

a high level of indebtedness may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes.

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

Our operations may be adversely affected by the European debt crisis.

During 2011, the long term structural deficits in numerous European nations coupled with the deterioration of the economic outlook led the weaker nations to a liquidity and solvency crisis. Eurozone leaders have made numerous attempts to solve this debt crisis; but, to date a sustainable long term solution has not been implemented and much uncertainty remains. The crisis has had a negative impact on major European banks which historically were significant providers of credit to the energy sector, globally and in the US.

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As of December 31, 2011, our Facility includes \$2.0 billion in aggregate total commitments of which \$153 million was available; approximately 60%, or \$91.0 million, of the undrawn availability under the Facility as of December 31, 2011 was with European financial institutions. If any of the financial institutions within our Facility are unable to perform on their commitments, our liquidity could be impacted which could have a significant negative impact on our earnings, cash flows and financial position.

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

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

recoverable reserves;

future oil and natural gas prices and their appropriate differentials;

development and operating costs; and

potential environmental and other liabilities.

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

diversion of our management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;

the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of ours while carrying on our ongoing business;

difficulty associated with coordinating geographically separate organizations; and

the challenge of attracting and retaining personnel associated with acquired operations.

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

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

The success of a significant acquisition will depend, in part, on our ability to realize anticipated growth opportunities from combining the acquired assets or operations with those of ours. Even if a combination is successful, it may not be possible to realize the full benefits we may expect in estimated

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proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame. Anticipated benefits of an acquisition may be offset by operating losses relating to changes in commodity prices, increased interest expense associated with debt incurred or assumed in connection with the transaction, adverse changes in oil and gas industry conditions, or by risks and uncertainties relating to the exploratory prospects of the combined assets or operations, or an increase in operating or other costs or other difficulties, including the assumption of environmental or other liabilities in connection with the acquisition. If we fail to realize the benefits we anticipate from an acquisition, our results of operations may be adversely affected.

We have a material weakness in our internal control over financial reporting. If we fail to establish and maintain proper and effective internal controls, our ability to produce accurate financial statements could be impaired, which could adversely affect our operating results, and investor, supplier and customer confidence in our reported financial information.

As described in "Item 9A. Controls and Procedures," during the quarter ended December 31, 2011, management determined that the Company had a material weaknesses in its system of internal control over financial reporting. A material weakness is a deficiency, or combination of deficiencies in internal controls over financial reporting that results in a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis. Specifically, management did not perform a sufficiently precise review to ensure the completeness and accuracy of the Company's calculation of its income tax provision related to our treatment of unrealized derivative losses. While the Company has taken steps to remediate this material weakness, at December 31, 2011, the Company had not yet completed its assessment as to whether the material weakness had been fully remediated. Until it is fully remediated, this material weakness could lead to errors in our reported financial results and could have a material adverse effect on our operations, investor, supplier and customer confidence in our reported financial information and the trading price of our common shares.

Because we are a relatively small company, the requirements of being a public company, including compliance with the reporting requirements of the Exchange Act and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management; and we may be unable to comply with these requirements in a timely or cost-effective manner.

As a public company with listed equity securities, we must comply with additional laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002, related regulations of the SEC and the requirements of the NYSE. Complying with these statutes, regulations and requirements will occupy a significant amount of time of our board of directors and management and will significantly increase our costs and expenses. We will need to:

institute a more comprehensive compliance function;

design, establish, evaluate and maintain a system of internal controls over financial reporting in compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002 and the related rules and regulations of the SEC and the Public Company Accounting Oversight Board;

comply with rules promulgated by the NYSE;

prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;

establish new internal policies, such as those relating to disclosure controls and procedures and insider trading; and

involve and retain to a greater degree outside counsel and accountants in the above activities.

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Lastly, we are evaluating the potential listing of our common shares on the Ghana Stock Exchange ("GSE"), although there can be no assurance that this listing will be completed in a timely manner, or at all. Complying with the regulations and requirements of the GSE may heighten the risks listed above.

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

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

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

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

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

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

The Bermuda Minister of Finance, under the Exempted Undertakings Tax Protection Act 1966 of Bermuda, as amended, has given us an assurance that if any legislation is enacted in Bermuda that would impose tax computed on profits or income, or computed on any capital asset, gain or

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appreciation, or any tax in the nature of estate duty or inheritance tax, then the imposition of any such tax will not be applicable to us or any of our operations, shares, debentures or other obligations until March 31, 2035, except insofar as such tax applies to persons ordinarily resident in Bermuda or to any taxes payable by us in respect of real property owned or leased by us in Bermuda.

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

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

The adoption of financial reform legislation by the United States Congress in 2010 could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price and other risks associated with our business.

We use derivative instruments to manage our commodity price risk. The United States Congress adopted comprehensive financial reform legislation in 2010 that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as ours, that participate in that market. The legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), was signed into law by the President on July 21, 2010, and its provisions generally are effective 360 days from the date of enactment, or July 16, 2011. Provisions that require rulemaking by the Commodities Futures Trading Commission (the "CFTC") and the SEC will not take effect until at least 60 days after publication of the related final rule. The CFTC and the SEC have not completed all of the rulemaking the Dodd-Frank Act directs them to carry out. The regulators have granted temporary relief from the general effective date for various requirements of the Dodd-Frank Act, and also have indicated they may phase in implementation of various requirements of the new rules. In its rulemaking under the Dodd-Frank Act, the CFTC has proposed regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions would be exempt from these position limits. The CFTC adopted these proposed regulations with modifications on October 18, 2011, but it is not possible at this time to predict when these regulations will take effect. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivatives activities, although the application of those provisions to us is uncertain at this time. The Dodd-Frank Act may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivatives contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. In addition, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to

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lower commodity prices. Lastly, the Dodd-Frank Act requires the SEC to promulgate rules requiring SEC reporting companies that engage in the commercial development of oil, natural gas or minerals, to include in their annual reports filed with the SEC disclosure about all payments (including taxes, royalties, fees and other amounts) made by the issuer or an entity controlled by the issuer to the United States or to any non-U.S. government for the purpose of commercial development of oil, natural gas or minerals. As these rules are not yet effective, we are unable to predict what form the final rules may take and whether we will be able to comply with them without adversely impacting our business, or at all. Any of these consequences could have a material adverse effect on our business, financial condition or results of operations.

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

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

We could incur a liability in connection with securities litigation.

On January 10, 2012, a lawsuit was filed in the 68th Judicial District Court of Dallas County, Texas, against Kosmos Energy Ltd., all of our directors, certain officers of the Company, Warburg Pincus LLC, Blackstone Capital Partners and the underwriters of our IPO, alleging violations of the federal securities laws. Specifically, the plaintiff alleged, among other things, that the defendants made materially false statements and omissions in the documents related to the IPO concerning anticipated gross oil production from the Jubilee Field and that the defendants failed to disclose that several wells were not producing as expected due to design defects that will purportedly cost hundreds of millions of dollars to remediate and will purportedly keep such wells from producing as expected for several years. The plaintiff seeks to certify the lawsuit as a class action lawsuit.

We intend to defend vigorously against the lawsuit and do not believe it will have a material adverse effect on our business. However, if we are unsuccessful in this litigation and any loss exceeds our available insurance, this could have a material adverse effect on our results of operations.

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

Risks Relating to Our Common Shares

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

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

the price of oil and natural gas;

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the success of our exploration and development operations, and the marketing of any oil and natural gas we produce;

regulatory developments in Bermuda, the United States and foreign countries where we operate;

the recruitment or departure of key personnel;

quarterly or annual variations in our financial results or those of companies that are perceived to be similar to us;

market conditions in the industries in which we compete and issuance of new or changed securities;

analysts' reports or recommendations;

the failure of securities analysts to cover our common shares or changes in financial estimates by analysts;

the inability to meet the financial estimates of analysts who follow our common shares;

the issuance of any additional securities of ours;

investor perception of our company and of the industry in which we compete; and

general economic, political and market conditions.

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

All of the shares sold in our IPO are freely tradable without restrictions or further registration under the federal securities laws, unless purchased by our "affiliates" as that term is defined in Rule 144 under the Securities Act of 1933, as amended (the "Securities Act"). Substantially all of the remaining common shares are restricted securities as defined in Rule 144 under the Securities Act. Restricted securities may be sold in the U.S. public market only if registered or if they qualify for an exemption from registration, including by reason of Rule 144 or Rule 701 under the Securities Act. All of our restricted shares became eligible for sale in the public market beginning in late 2011, subject in certain circumstances to the volume, manner of sale and other limitations under Rule 144. Additionally, we have registered all our common shares that we may issue under our employee benefit plans. These shares can be freely sold in the public market upon issuance, unless pursuant to their terms these share awards have transfer restrictions attached to them. Sales of a substantial number of our common shares, or the perception in the market that the holders of a large number of shares intend to sell common shares, could reduce the market price of our common shares.

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

Our two largest shareholders collectively own approximately 72% of our issued and outstanding common shares. Consequently, these shareholders have significant influence over all matters that require approval by our shareholders, including the election of directors and approval of significant corporate transactions. This concentration of ownership will limit your ability to influence corporate matters, and as a result, actions may be taken that you may not view as beneficial.

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

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We may issue additional common shares, preferred shares, warrants, rights, units and debt securities for general corporate purposes, including, but not limited to, repayment or refinancing of

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borrowings, working capital, capital expenditures, investments and acquisitions. We continue to actively seek to expand our business through complementary or strategic acquisitions of assets, and we may issue additional common shares in connection with those acquisitions. We also issue restricted shares to our executive officers, employees and independent directors as part of their compensation. If we issue additional common shares in the future, it may have a dilutive effect on our current outstanding shareholders.

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

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

a majority of the board of directors consist of independent directors;

the nominating and corporate governance committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities;

the compensation committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and

there be an annual self assessment evaluation of the nominating and corporate governance and compensation committees.

We have elected to be treated as a controlled company and utilize these exemptions, including the exemption for a board of directors composed of a majority of independent directors. In addition, although we have adopted charters for our audit, nominating and corporate governance and compensation committees and intend to conduct annual self assessment for these committees, currently, none of these committees are composed entirely of independent directors. We have elected to rely on the phase-in rules of the SEC and the NYSE with respect to the independence of our audit committee. These rules permit us to have an audit committee that has one member that is independent upon the effectiveness of the registration statement for our IPO, a majority of members that are independent within 90 days thereafter and all members that are independent within one year thereafter. Accordingly, you may not have the same protections afforded to shareholders of companies that are subject to all of the NYSE corporate governance requirements.

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

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

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

We are a Bermuda exempted company. As a result, the rights of holders of our common shares will be governed by Bermuda law and our memorandum of association and bye-laws. The rights of

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

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

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

Interested Directors. Under Bermuda law and our bye-laws, as long as a director discloses a direct or indirect interest in any contract or arrangement with us as required by law, such director is entitled to vote in respect of any such contract or arrangement in which he or she is interested, unless disqualified from doing so by the chairman of the meeting, and such a contract or arrangement will not be voidable solely as a result of the interested director's participation in its approval. In addition, the director will not be liable to us for any profit realized from the transaction. In contrast, under Delaware law, such a contract or arrangement is voidable unless it is approved by a majority of disinterested directors or by a vote of shareholders, in each case if the material facts as to the interested director's relationship or interests are disclosed or are known to the disinterested directors or shareholders, or such contract or arrangement is fair to the corporation as of the time it is approved or ratified. Additionally, such interested director could be held liable for a transaction in which such director derived an improper personal benefit.

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

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circumstances, be entitled to appraisal rights pursuant to which such shareholder may receive cash in the amount of the fair value of the shares held by such shareholder (as determined by a court) in lieu of the consideration such shareholder would otherwise receive in the transaction.

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

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

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

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

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

See "Item 1. Business." We also have various operating leases for rental of office space, office and field equipment, and vehicles. See Note 18 of Notes to the Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for the future minimum rental payments. Such information is incorporated herein by reference.

Item 3. Legal Proceedings

On January 10, 2012, a lawsuit was filed in the 68th Judicial District Court of Dallas County, Texas, against Kosmos Energy Ltd., all of our directors, certain officers of the Company, Warburg

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Pincus LLC, Blackstone Capital Partners and the underwriters of our IPO, alleging violations of the federal securities laws. Specifically, the plaintiff alleged, among other things, that the defendants made materially false statements and omissions in the documents related to the IPO concerning anticipated gross oil production from the Jubilee Field and that the defendants failed to disclose that several wells were not producing as expected due to design defects that will purportedly cost hundreds of millions of dollars to remediate and will purportedly keep such wells from producing as expected for several years. The plaintiff seeks to certify the lawsuit as a class action lawsuit.

We believe that these claims are without merit and intend to defend this lawsuit vigorously. We are cooperating with our directors and officers liability insurance carrier regarding the vigorous defense of the lawsuit. We currently believe that the potential amount of losses resulting from this lawsuit in the future, if any, will not exceed the policy limits of our directors' and officers' insurance.

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

Item 4. Mine Safety Disclosure

Not applicable.

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Kosmos' common shares are traded on the NYSE under the symbol "KOS." The following table shows the quarterly high and low sale prices of our common shares as reported on the NYSE since our common shares commenced trading on the NYSE on May 11, 2011 in connection with our IPO.

	Year Ended December 31, 2011	
	High	Low
First Quarter	\$ N/A	\$ N/A
Second Quarter	19.24	16.63
Third Quarter	17.32	11.51
Fourth Quarter	16.19	10.53

As of February 17, 2012, based on information from the Company's transfer agent, Computershare Trust Company, N.A., the number of holders of record of Kosmos' common shares was 197. On February 17, 2012, the last reported sale price of Kosmos' common shares, as reported on the NYSE, was \$14.48 per share.

We have never paid any dividends on our common shares. At the present time, we intend to retain all of our future earnings, if any, generated by our operations for the development and growth of our business. Additionally, we are subject to Bermuda legal constraints that may affect our ability to pay dividends on our common shares and make other payments. Under the Bermuda Companies Act, we may not declare or pay a dividend if there are reasonable grounds for believing that we are, or would after the payment be, unable to pay our liabilities as they become due or that the realizable value of our assets would thereafter be less than the aggregate of our liabilities, issued share capital and share premium accounts. Certain of our subsidiaries are also currently restricted in their ability to pay dividends to us pursuant to the terms of our commercial debt facility unless we meet certain conditions, financial and otherwise. Any decision to pay dividends in the future is at the discretion of our board of directors and depends on our financial condition, results of operations, capital requirements and other factors that our board of directors deems relevant and currently do not anticipate paying any dividends in the foreseeable future.

Unregistered Sales of Equity Securities and Use of Proceeds

Our IPO of common shares was effected through a Registration Statement on Form S-1 (File No. 333-171700) that was declared effective by the SEC on May 10, 2011, which (combined with the Registration Statement on Form S-1 (File No. 333-174116)) registered an aggregate of 38.0 million of our common shares at a public offering price of \$18.00 per share. Our IPO resulted in gross proceeds of approximately \$621.3 million. Our net proceeds from the sale of an aggregate of 34.5 million common shares after underwriting discounts and commissions and offering expenses of \$40.9 million were approximately \$580.4 million.

There has been no material change in our planned use of proceeds from the IPO from that described in our final prospectus dated May 10, 2011 and filed with the SEC pursuant to Rule 424(b).

During 2011, we used net proceeds to repay indebtedness under our Facility, to pay funds to GNPC as part of our settlement agreement with GNPC and the Government of Ghana and for general corporate purposes. Pending use of the remaining net proceeds, we have invested these net proceeds in institutionally-managed accounts that consists of highly rated investment funds.

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Share Performance Graph

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

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

	May 11, 2011	December 31, 2011
Kosmos Energy Ltd.	\$ 100.00	\$ 67.21
S&P 500	100.00	93.71
SIG Oil Exploration & Production Index	100.00	83.69

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The following selected consolidated financial information set forth below as of and for the five years ended, December 31, 2011, should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data."

Consolidated Statements of Operations Information:

	Year Ended December 31,				
	2011(1)	2010	2009	2008	2007
	(In thousands, except per share data)				
Revenues and other income:					
Oil and gas revenue	\$ 666,912	\$	\$	\$	\$
Interest income	9,093	4,231	985	1,637	1,568
Other income	775	5,109	9,210	5,956	2
Total revenues and other income	676,780	9,340	10,195	7,593	1,570
Costs and expenses:					
Oil and gas production	83,551				
Exploration expenses, including dry holes	126,409	73,126	22,127	15,373	39,950
General and administrative	113,579	98,967	55,619	40,015	18,556
Depletion, depreciation and amortization	140,469	2,423	1,911	719	477
Amortization deferred financing costs	16,193	28,827	2,492		
Interest expense	65,749	59,582	6,774	1	8
Derivatives, net	11,777	28,319			
Equity in losses of joint venture					2,632
Loss on extinguishment of debt	59,643				
Doubtful accounts expense	(39,782)	39,782			
Other expenses, net	149	1,094	46	21	17
Total costs and expenses	577,737	332,120	88,969	56,129	61,640
Income (loss) before income taxes	99,043	(322,780)	(78,774)	(48,536)	(60,070)
Income tax expense (benefit)	76,686	(77,108)	973	269	718
Net income (loss)	\$ 22,357	\$ (245,672)	\$ (79,747)	\$ (48,805)	\$ (60,788)
Accretion to redemption value of convertible preferred units	(24,442)	(77,313)	(51,528)	(21,449)	(8,505)
Net loss attributable to common shareholders/unit holders	\$ (2,085)	\$ (322,985)	\$ (131,275)	\$ (70,254)	\$ (69,293)
Net income per share attributable to common shareholders, as restated(2):					
Basic (represents the period from May 16, 2011 to December 31, 2011)	\$ 0.09				
Diluted (represents the period from May 16, 2011 to December 31, 2011)	\$ 0.09				
Weighted average number of shares used to compute net income per share, as restated(2):					
Basic (represents the period from May 16, 2011 to December 31, 2011)	368,474				

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Diluted (represents the period from May 16, 2011 to December 31, 2011)

368,607

(1)

Pursuant to the terms of our corporate reorganization that was completed simultaneously with the closing of the IPO, all of the interests in Kosmos Energy Holdings were exchanged for newly issued common shares of Kosmos Energy Ltd. based on these interests' relative rights as set forth in Kosmos

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Energy Holdings' then-current operating agreement. This included convertible preferred units of Kosmos Energy Holdings which were redeemed upon the consummation of the qualified public offering (as defined in the operating agreement in effect prior to the IPO) into common shares of Kosmos Energy Ltd. based on the pre-offering equity value of such interests.

(2)

See Notes 2 and 16 to the consolidated financial statements.

Consolidated Balance Sheets Information:

	As of December 31,				
	2011	2010	2009	2008	2007
	(In thousands)				
Cash and cash equivalents	\$ 673,092	\$ 100,415	\$ 139,505	\$ 147,794	\$ 39,263
Total current assets	1,112,481	559,920	256,728	205,708	65,960
Total property and equipment	1,377,041	998,000	604,007	208,146	18,022
Total other assets	62,412	133,615	161,322	1,611	3,393
Total assets	2,551,934	1,691,535	1,022,057	415,465	87,375
Total current liabilities	339,607	482,057	139,647	68,698	28,574
Total long-term liabilities	1,191,601	845,383	287,022	444	
Total convertible preferred units		978,506	813,244	499,656	167,000
Total shareholders' equity/unit holdings equity	1,020,726	(614,411)	(217,856)	(153,333)	(108,199)
Total liabilities, convertible preferred units and shareholders' equity/unit holdings equity	2,551,934	1,691,535	1,022,057	415,465	87,375

Consolidated Statements of Cash Flows Information:

	Year Ended December 31,				
	2011	2010	2009	2008	2007
	(In thousands)				
Net cash provided by (used in):					
Operating activities	\$ 364,909	\$ (191,800)	\$ (27,591)	\$ (65,671)	\$ (17,386)
Investing activities	(385,140)	(589,975)	(500,393)	(156,882)	(58,161)
Financing activities	592,908	742,685	519,695	331,084	104,973
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Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

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

Overview

We are an independent oil and gas exploration and production company currently focused on frontier and emerging areas in Africa and South America. Our asset portfolio includes existing production, major discoveries and exploration prospects offshore Ghana, as well as exploration licenses with significant hydrocarbon potential offshore Morocco and Suriname and onshore Cameroon.

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. Pursuant to the terms of a corporate reorganization that was completed immediately prior to the closing of Kosmos Energy Ltd.'s IPO on May 16, 2011, all of the interests in Kosmos Energy Holdings were exchanged for newly issued common shares of Kosmos Energy Ltd. As a result, Kosmos Energy Holdings became wholly owned by Kosmos Energy Ltd.

Kosmos Energy Ltd. transitioned from its development stage to operational activities in January 2011. Accordingly, reporting as a development stage company is no longer deemed necessary.

2011 Highlights

Ghana Jubilee Field

During 2011, we had six liftings of oil totaling 5,971 Mbbls from the Jubilee Field Phase 1 production resulting in revenues of \$666.9 million. Our average realized price per barrel was \$111.70.

A total of 17 development wells have been drilled during Jubilee Field Phase 1 development. The Jubilee Field Phase 1A PoD was approved by the Ministry of Energy and GNPC in January 2012. The Phase 1A PoD includes eight additional wells to be drilled beginning in 2012, including five production wells and three water injection wells.

Pursuant to the terms of the Jubilee UUA, the unit participation interests are subject to a process of redetermination. The initial redetermination process was completed on October 14, 2011. As a result of the initial redetermination process, the tract participation was determined to be 54.36660% for the WCTP Block and 45.63340% for the DT Block. Our Unit Interest (participating interest in the Jubilee Unit) was increased from 23.50868% (our percentage after Tullow's acquisition of EO Group's interest in July 2011) to 24.07710%.

In December 2011, Tullow, as Unit Operator for and on behalf of the Jubilee Unit acquired the FPSO we are using to produce hydrocarbons from the Jubilee Field from MODEC, Inc. ("MODEC") for \$754.5 million, or \$202.6 million net to Kosmos. At the time of the acquisition of the FPSO, the note receivable under the Advance Payments Agreement was \$102.8 million. To fund the purchase, we paid \$99.8 million in cash and applied the note receivable due under the Advance Payments Agreement to the purchase. Prior to the acquisition of the FPSO, the Jubilee Unit leased the FPSO from MODEC and the associated costs were recorded as oil and gas production expense. The purchase price was recorded as an addition to oil and gas properties. In 2012 and future periods, these costs will be depleted on the unit of production method. The Jubilee Unit Operator became the operator of the FPSO, with MODEC providing services under an operations and maintenance agreement.

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Ghana WCTP Block exploration and appraisal activity

In 2011, the Teak-1, Teak-2 and Teak-3 wells intersected multiple oil, gas and natural gas condensate bearing reservoirs in Campanian and Turonian zones. Fluid samples recovered from the wells indicate an oil gravity of between 32 and 39 degrees API and natural gas condensate gravity of between 40 and 45 degrees API.

In June 2011, we announced that the Banda-1 exploration well had made a hydrocarbon discovery. We believe the target reservoir is a channel fairway that is stratigraphically trapped. The well intersected quantities of oil-bearing reservoirs in Cenomanian to Albian zones, although the well is considered sub-commercial. The Banda discovery represents a new play in the WCTP Block.

In August 2011, we announced the Akasa-1 exploration well had made a hydrocarbon discovery. Fluid samples recovered from the well indicates an oil gravity of 38 degrees API.

The WCTP PA, which governs our activities related to the WCTP Block, has a duration of 30 years from its effective date (July 2004); however, in July 2011, at the end of the seven-year exploration phase, 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 subject to relinquishment ("WCTP Relinquishment Area"). Our existing discoveries within the WCTP Block have not been relinquished, as the WCTP PA remains in effect after the end of the exploration phase and these are Akasa, Banda, Mahogany East and Teak. In addition, we have disputed the relinquishment of the area around the Cedrela prospect. In July 2011, immediately prior to Kosmos receiving the drilling rig from another operator, damage to the rig incurred during preparations to move the rig to the WCTP Block rendered the rig incapable of drilling the Cedrela-1 exploration well prior to the end of the WCTP exploration period on July 21, 2011. As a result of this unforeseen delay in the drilling of the Cedrela-1 exploration well, the Company, as Operator for the WCTP PA Block partners, delivered a Notice of Force Majeure. The Ministry of Energy and GNPC did not agree this event was Force Majeure. On August 24, 2011, we as Operator of the WCTP Block and on behalf of the WCTP PA Block partners, delivered a Notice of Dispute to the Ministry of Energy and GNPC as provided under the WCTP PA, which is the initial step in triggering the formal dispute resolution process under the WCTP PA with the Government of Ghana regarding our rights to drill the Cedrela-1 exploration well. This Notice of Dispute establishes a process for negotiation and consultation for a period of 30 days (or longer if mutually agreed) among senior representatives from the Ministry of Energy, GNPC and the WCTP Block partners to resolve the matter. The issue continues to be discussed in an effort to reach a mutually agreed upon resolution among the parties. See "Item 1A. Risk Factors We 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."

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 exercised such right in July 2010 and formally submitted a proposed new petroleum agreement for the WCTP Relinquishment Area in early 2011. We and our WCTP Block partners, the Ghana Ministry of Energy and GNPC have agreed such WCTP PA rights extend from July 21, 2011 until such time as either a new petroleum contract is negotiated and entered into with us or we decline to match a bona fide third party offer GNPC may receive for the WCTP Relinquishment Area.

Ghana DT Block exploration and appraisal activity

In April 2011, the Tweneboa-4 appraisal well successfully confirmed the resource base potential of the Tweneboa Field. The well encountered gas-condensate pay in high-quality stacked reservoir sandstones. In January 2011, the Tweneboa-3ST well encountered net gas-condensate pay in high-quality stacked reservoir sandstones in two zones. We determined the sidetrack on the Tweneboa-3 encountered the Ntomme field, a separate discovery area.

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In January 2012, the Ntomme-2A appraisal well confirmed a downdip extension of the Ntomme Field, which was discovered by the Tweneboa-3ST. The well encountered high-quality stacked reservoir sandstones. The well confirmed the majority of the resources in the discovery to be oil. Fluid samples recovered from the wells indicate an oil gravity of approximately 35 degrees API.

In May 2011 and August 2011, the Tweneboa-2 drill stem test flowed oil and the Tweneboa-4 drill stem test flowed natural gas condensate.

In March 2011, the Enyenra-2A appraisal confirmed a downdip extension of the Enyenra Field (formerly known as Owo), which was discovered by the Owo-1 exploration well. The Enyenra-2A well encountered oil and gas-condensate in high-quality stacked sandstone reservoirs. Results of drilling, wireline logs, reservoir fluid samples and pressure data show that the Enyenra-2A well intersected oil in the upper channel and lower channel. The Enyenra-2A well also tested a portion of a deeper reservoir where gas-condensate sandstones were intersected in the Tweneboa Deep discovery. Fluid samples recovered from the well indicate a natural gas condensate gravity of approximately 46 degrees API.

In September 2011, the Enyenra-3A appraisal well confirmed an updip extension of the Enyenra light oil field. Analysis of well results, including wireline logs, reservoir pressures and fluid samples indicated the Enyenra-3A well encountered oil-bearing pay. Fluid samples recovered from the well indicate an oil gravity of approximately 35 degrees API.

The first extension period of the exploration phase of the DT Block expired on January 19, 2011. In accordance with the DT PA, Tullow, on behalf of the DT Block partners, formally extended the DT PA into the second extension period and relinquished 25% of the DT Block. The seven-year exploration phase of the DT PA will expire in January 2013. Our existing discoveries within the DT Block are not subject to relinquishment upon expiration of the exploration phase of the DT PA, as the DT PA remains in effect after the end of the exploration phase, and these are Tweneboa, Enyenra and Ntomme. We and our DT Block partners have certain rights of first refusal for the granting of a new petroleum contract and certain rights to negotiate a new petroleum contract with respect to the DT Relinquishment Area. We and our DT Block partners exercised such right to negotiate a new petroleum contract in January 2012.

Morocco

During 2011, we increased our acreage positions offshore the Kingdom of Morocco by acquiring two new petroleum contracts, renewing an existing petroleum contract and acquiring a new reconnaissance contract. Our exploration licenses include Cap Boujdour Offshore Block, which is within the Aaiun Basin, and Essaouira Offshore Block and Foum Assaka Offshore Block, which are within the Agadir Basin. Our reconnaissance contract is over the Tarhazoute Offshore area within the Agadir Basin. Kosmos is the operator of the blocks and has a 75% participating interest in the Cap Boujdour Offshore Block, a 37.5% participating interest in the Essaouira Offshore Block and Foum Assaka Offshore Block, and a 100% interest in the reconnaissance contract covering the Tarhazoute Offshore area. Upon receipt of approval from the Moroccan government, we will acquire an additional 18.75% participating interest in the Foum Assaka Offshore Block from Pathfinder Hydrocarbon Ventures Ltd., one of our block partners.

We are currently acquiring a 4,800 square kilometer 3D seismic data acquisition program in the Agadir Basin. Approximately half of the data to be acquired covers the Essaouira Offshore Block with the remainder in the Foum Assaka Block.

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Cameroon

In an order dated March 3, 2011, the Minister of Industry, Mines and Technology Development confirmed our entry into the first renewal period of the Ndian River petroleum contract.

In January 2012, Kosmos entered into a license with Cameroon for the Fako Block. Kosmos is the operator and has a 100% participating interest in the block. The block covers 318,519 acres (1,289 square kilometers) and borders the southeast portion of our Ndian River Block in the Rio del Rey Basin.

Suriname

Kosmos' new ventures effort extended beyond our historical West Africa focus area as we entered into two Production Sharing Contracts in South America. In December 2011, Kosmos entered into Production Sharing Contracts for Blocks 42 and 45 offshore Suriname. Kosmos is the operator and has a 100% participating interest in Suriname offshore Block 42 and a 100% participating interest in Suriname offshore Block 45.

Results of Operations

All of our results from operations relates to production from the Jubilee Field in Ghana. Certain operating results and statistics for the comparative years of 2011, 2010 and 2009 are included in the following table:

(In thousands, except per barrel data)	Years Ended December 31,		
	2011	2010	2009
Sales volumes:			
Mbbls	5,971		
Revenues:			
Oil sales	\$ 666,912	\$	\$
Average sales price per bbl	111.70		
Costs:			
Oil production	\$ 83,551	\$	\$
Depletion	135,532		
Average oil production cost per bbl	\$ 13.99	\$	\$
Average depletion cost per bbl	22.70		
Average oil production cost and depletion per bbl	\$ 36.69	\$	\$

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

Year Ended December 31, 2011 vs. 2010

	Years Ended December 31,		Increase (Decrease)
	2011	2010	
	(In thousands)		
Revenues and other income:			
Oil and gas revenue	\$ 666,912	\$	\$ 666,912
Interest income	9,093	4,231	4,862
Other income	775	5,109	(4,334)
Total revenues and other income	676,780	9,340	667,440
Costs and expenses:			
Oil and gas production	83,551		83,551
Exploration expenses, including dry holes	126,409	73,126	53,283
General and administrative	113,579	98,967	14,612
Depletion and depreciation	140,469	2,423	138,046
Amortization deferred financing costs	16,193	28,827	(12,634)
Interest expense	65,749	59,582	6,167
Derivatives, net	11,777	28,319	(16,542)
Loss on extinguishment of debt	59,643		59,643
Doubtful accounts expense	(39,782)	39,782	(79,564)
Other expenses, net	149	1,094	(945)
Total costs and expenses	577,737	332,120	245,617
Income (loss) before income taxes	99,043	(322,780)	421,823
Income tax expense (benefit)	76,686	(77,108)	153,794
Net income (loss)	\$ 22,357	\$ (245,672)	\$ 268,029

Oil and gas revenue. During the year ended December 31, 2011, we recorded oil revenues of \$666.9 million due to oil production from the Jubilee Field. We lifted and sold approximately 5,971 Mbbls at an average realized price per barrel of \$111.70. In 2010, we had no oil sales and, therefore, no associated revenues.

Interest income. Interest income increased by \$4.9 million during the year ended December 31, 2011, as compared to the year ended December 31, 2010, primarily due to interest on notes receivable. The related note receivable was retired in December 2011 as part of the acquisition of the FPSO we are using to produce hydrocarbons from the Jubilee Field.

Other income. Other income decreased by \$4.3 million during the year ended December 31, 2011, as compared to the year ended December 31, 2010, primarily due to a decrease in technical services fees and overhead charges billed to the Unit Operator for services provided on the Jubilee Field Phase 1 development.

Oil and gas production. During the year ended December 31, 2011, we recorded oil and gas production costs of \$83.6 million related to oil production from the Jubilee Field. Our average production cost per barrel was \$13.99. In 2010, there were no oil sales and, therefore, no associated oil and gas production costs.

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Exploration expenses. Exploration expenses increased by \$53.3 million during the year ended December 31, 2011, as compared to the year ended December 31, 2010. During the year ended December 31, 2011, we incurred \$32.8 million for seismic costs and \$91.3 million of unsuccessful well costs, primarily related to the Cameroon N'gata-1, Ghana Makore-1, Ghana Banda-1 and Ghana Odum exploration wells. During the year ended December 31, 2010, the Company incurred \$59.4 million of unsuccessful well costs primarily related to the Ghana Dahoma-1 and Cameroon Mombe-1 wells and \$13.0 million for seismic costs.

General and administrative. General and administrative costs increased by \$14.6 million during the year ended December 31, 2011, as compared to the year ended December 31, 2010, primarily due to an increase in staffing and increases in non-cash expenses of \$37.2 million for equity-based compensation, partially offset by decreases in cash expenses for professional fees. Total non-cash general and administrative costs were \$51.0 million and \$13.8 million for the years ended December 31, 2011 and 2010, respectively.

Depletion and depreciation. Depletion and depreciation increased \$138.0 million during the year ended December 31, 2011, as compared with the year ended December 31, 2010, due to production from the Jubilee Field. In 2010, there were no oil sales and, therefore, no associated depletion.

Amortization deferred financing costs and Loss on extinguishment of debt. During the year ended December 31, 2011, we incurred approximately \$52.3 million of deferred financing costs as part of our debt refinance, in addition to our existing unamortized deferred financing costs of \$68.6 million. As a result of the debt refinance, we recorded a \$59.6 million loss on the extinguishment of debt. The remaining costs were capitalized and are being amortized over the term of the Facility. The related amortization of deferred financing costs decreased by \$12.6 million during the year ended December 31, 2011, as compared to the year ended December 31, 2010, due to the decrease in capitalized deferred financing costs and the longer term associated with the Facility.

Interest expense. Interest expense increased by \$6.2 million during the year ended December 31, 2011, as compared to the year ended December 31, 2010, primarily due to a decrease in capitalized interest and higher average outstanding debt during the year ended December 31, 2011.

Derivatives, net. Derivatives, net decreased \$16.5 million during the year ended December 31, 2011, as compared with December 31, 2010, due to the change in fair value of the commodity derivative instruments.

Doubtful accounts expense. During the year ended December 31, 2011, we released a \$39.8 million allowance for doubtful accounts related to a receivable previously in default. We received the full amount of the receivable during the third quarter of 2011.

Income tax expense (benefit). The Company recognized an income tax provision attributable to earnings of \$76.7 million during 2011 and an income tax benefit of \$77.1 million during 2010. The Company's effective tax rates for 2011 and 2010 were 77.4% and 23.9%, respectively. The large variance in income taxes between 2011 and 2010 is due to the release of the Ghana valuation allowance in 2010. The large effective tax rate in 2011 is primarily due to the fact that no tax benefit is currently being provided on losses in jurisdictions with a full valuation allowance and jurisdictions where no income tax is assessed.

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	Years Ended December 31		Increase (Decrease)
	2010	2009	
	(In thousands)		
Revenues and other income:			
Oil and gas revenue	\$	\$	\$
Interest income	4,231	985	3,246
Other income	5,109	9,210	(4,101)
Total revenues and other income	9,340	10,195	(855)
Costs and expenses:			
Exploration expenses, including dry holes	73,126	22,127	50,999
General and administrative	98,967	55,619	43,348
Depletion, depreciation and amortization	2,423	1,911	512
Amortization deferred financing costs	28,827	2,492	26,335
Interest expense	59,582	6,774	52,808
Derivatives, net	28,319		28,319
Doubtful accounts expense	39,782		39,782
Other expenses, net	1,094	46	1,048
Total costs and expenses	332,120	88,969	243,151
Loss before income taxes	(322,780)	(78,774)	(244,006)
Income tax expense (benefit)	(77,108)	973	(78,081)
Net loss	\$ (245,672)	\$ (79,747)	\$ (165,925)

Oil and gas revenue. We commenced oil and natural gas production on November 28, 2010 and received our first revenues from such production in early 2011; therefore, we did not realize any oil and gas revenue during the years ended December 31, 2010 and 2009.

Interest income. Interest income increased by \$3.2 million during the year ended December 31, 2010, as compared to the year ended December 31, 2009, due to interest accrued on receivables joint interest billings, as we had a higher outstanding receivable balance in 2010.

Other income. Other income decreased by \$4.1 million during the year ended December 31, 2010, as compared to the year ended December 31, 2009, primarily due to a decrease in technical services fees and overhead charges billed to the Unit Operator as a result of the Jubilee Field Phase 1 development nearing completion.

Exploration expenses. Exploration expenses increased by \$51.0 million during the year ended December 31, 2010, as compared to the year ended December 31, 2009, primarily due to unsuccessful well costs of \$28.4 million and \$26.0 million for the Ghana Dahoma-1 well and Cameroon Mombe-1 well, respectively, and an increase in purchases of seismic data for Ghana of \$5.6 million offset by a decrease in purchases of seismic data for Morocco of \$12.9 million.

General and administrative. General and administrative costs increased by \$43.3 million during the year ended December 31, 2010, as compared to the year ended December 31, 2009, due to non-recurring charges of approximately \$23.0 million, which includes a \$15.0 million accrual that was payable upon the successful completion of our IPO pursuant to our settlement agreement entered into with GNPC and the Government of Ghana in December 2010, increases in professional fees and expenses of \$6.1 million, unit-based compensation of \$10.4 million and operator charges of \$4.3 million, offset in part by increases in capitalized technical service fees of \$4.4 million.

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Amortization deferred financing costs. Amortization deferred financing costs increased by \$26.3 million during the year ended December 31, 2010, as compared to the year ended December 31, 2009, due to the amortization of the fees which were capitalized in connection with the initial draw on the commercial debt facilities in November 2009.

Interest expense. Interest expense increased by \$52.8 million during the year ended December 31, 2010, as compared to the year ended December 31, 2009, \$49.6 million d