UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2012

☐ **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 ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the voting and non-voting common shares held by non-affiliates, based on the per-share closing price of the registrant's common shares as of the last business day of the registrant's most recently completed second fiscal quarter was $778,343,016.

The number of the registrant's Common Shares outstanding as of February 18, 2013 was 388,593,342.

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 June 3, 2013.

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

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Unless otherwise stated in this report, references to "Kosmos," "we," "us" or "the company" refer to Kosmos Energy 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 SELECTED 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.

"2D seismic data"	Two-dimensional seismic data, serving as interpretive data that allows a view of a vertical cross-section beneath a prospective area.
"3D seismic data"	Three-dimensional seismic data, serving as geophysical data that depicts the subsurface strata in three dimensions. 3D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than 2D seismic data.
"API"	A specific gravity scale, expressed in degrees, that denotes the relative density of various petroleum liquids. The scale increases inversely with density. Thus lighter petroleum liquids will have a higher API than heavier ones.
"ASC"	Financial Accounting Standards Board Accounting Standards Codification.
"ASU"	Financial Accounting Standards Board Accounting Standards Update.
"Barrel" or "Bbl"	A standard measure of volume for petroleum corresponding to approximately 42 gallons at 60 degrees Fahrenheit.
"BBbl"	Billion barrels of oil.
"BBoe"	Billion barrels of oil equivalent.
"Bcf"	Billion cubic feet.
"Boe"	Barrels of oil equivalent. Volumes of natural gas converted to barrels of oil using a conversion factor of 6,000 cubic feet of natural gas to one barrel of oil.
"Boepd"	Barrels of oil equivalent per day.
"Bopd"	Barrels of oil per day.
"Bwpd"	Barrels of water per day.
"Debt cover ratio"	The "debt cover ratio" is broadly defined, for each applicable calculation date, as the ratio of (x) total long-term debt less cash and cash equivalents and restricted cash, to (y) the aggregate EBITDAX (see below) of the Company for the previous twelve months.
"Developed acreage"	The number of acres that are allocated or assignable to productive wells or wells capable of production.
"Development"	The phase in which an oil or natural gas field is brought into production by drilling development wells and installing appropriate production systems.

"Dry hole"	A well that has not encountered a hydrocarbon bearing reservoir expected to produce in commercial quantities.
"EBITDAX"	Net income (loss) plus (1) exploration expense, (2) depletion, depreciation and amortization expense, (3) equity-based compensation expense, (4) (gain) loss on commodity derivatives, (5) (gain) loss on sale of oil and gas properties, (6) interest (income) expense, (7) income taxes, (8) loss on extinguishment of debt, (9) doubtful accounts expense, and (10) similar items.
"E&P"	Exploration and production.
"FASB"	Financial Accounting Standards Board.
"Farm-in"	An agreement whereby an oil company acquires a portion of the participating interest in a block from the owner of such interest, usually in return for cash and for taking on a portion of the drilling costs of one or more specific wells or other performance by the assignee as a condition of the assignment.
"Field life cover ratio"	The "field life cover ratio" is broadly defined, for each applicable forecast period, as the ratio of (x) net present value of net cash flow through the depletion of the Jubilee Field plus the net present value of certain capital expenditures incurred in relation to the Jubilee Field and certain other fields in Ghana, to (y) the aggregate loan amounts outstanding under the Facility.
"FPSO"	Floating production, storage and offloading vessel.
"Ghana Obligors"	Kosmos Energy Operating, Kosmos Energy International, Kosmos Energy Finance International, Kosmos Energy Development, Kosmos Energy Ghana HC and an "Obligor" from time to time, as defined under the Facility Agreement, as amended and restated, dated November 23, 2012.
"Interest cover ratio"	The "interest cover ratio" is broadly defined, for each applicable calculation date, as the ratio of (x) the aggregate EBITDAX (see above) of the Company for the previous twelve months, to (y) interest expense less interest income for the Company for the previous twelve months.
"Loan life cover ratio"	The "loan life cover ratio" is broadly defined, for each applicable forecast period, as the ratio of (x) net present value of net cash flow through the final maturity date of the Facility plus the net present value of capital expenditures incurred in relation to the Jubilee Field and certain other fields in Ghana, to (y) the aggregate loan amounts outstanding under the Facility.
"MBbl"	Thousand barrels of oil.
"Mcf"	Thousand cubic feet of natural gas.
"Mcfpd"	Thousand cubic feet per day of natural gas.

"MMBbl" . . . . Million barrels of oil.

"MMBoe" . . . . Million barrels of oil equivalent.

"MMcf" . . . . Million cubic feet of natural gas.

"Natural gas liquid" or "NGL" . . . . . . Components of natural gas that are separated from the gas state in the form of liquids. These include propane, butane, and ethane, among others.

"Petroleum contract" . . . . A contract in which the owner of minerals gives an E&P company temporary and limited rights, including an exclusive option to explore for, develop, and produce minerals from the lease area.

"Petroleum system" . . . . A petroleum system consists of organic material that has been buried at a sufficient depth to allow adequate temperature and pressure to expel hydrocarbons and cause the movement of oil and natural gas from the area in which it was formed to a reservoir rock where it can accumulate.

"Plan of development" or "PoD" . . . . A written document outlining the steps to be undertaken to develop a field.

"Productive well" . . . . An exploratory or development well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

"Prospect(s)" . . . . A potential trap that may contain hydrocarbons and is supported by the necessary amount and quality of geologic and geophysical data to indicate a probability of oil and/or natural gas accumulation ready to be drilled. The five required elements (generation, migration, reservoir, seal and trap) must be present for a prospect to work and if any of them fail neither oil nor natural gas will be present, at least not in commercial volumes.

"Proved reserves" . . . . Estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be economically recoverable in future years from known reservoirs under existing economic and operating conditions, as well as additional reserves expected to be obtained through confirmed improved recovery techniques, as defined in SEC Regulation S-X 4-10(a)(2).

"Proved developed reserves" . . . . Proved developed reserves are those proved reserves that can be expected to be recovered through existing wells and facilities and by existing operating methods.

"Proved undeveloped reserves" . . . . . . 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.

"Reconnaissance contract"	A contract in which the owner of minerals gives an E&P company rights to perform evaluation of existing data or potentially acquire additional data but does not convey an exclusive option to explore for, develop, and/or produce minerals from the lease area.
"Shelf margin"	The path created by the change in direction of the shoreline in reaction to the filling of a sedimentary basin.
"Structural trap"	A structural strap 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.
"Structural-stratigraphic trap"	A structural-stratigraphic trap is a combination trap with structural and stratigraphic features.
"Stratigraphy"	The study of the composition, relative ages and distribution of layers of sedimentary rock.
"Stratigraphic trap"	A stratigraphic trap is formed from a change in the character of the rock rather than faulting or folding of the rock and oil is held in place by changes in the porosity and permeability of overlying rocks.
"Submarine fan"	A fan-shaped deposit of sediments occurring in a deep water setting where sediments have been transported via mass flow, gravity induced, processes from the shallow to deep water. These systems commonly develop at the bottom of sedimentary basins or at the end of large rivers.
"Three-way fault trap"	A structural trap where at least one of the components of closure is formed by offset of rock layers across a fault.
"Trap"	A configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not migrate.
"Undeveloped acreage"	Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains discovered resources.

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, Mauritania, 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;
- 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;

- the cost and availability of adequate insurance coverage;
- our vulnerability to severe weather events;
- our ability to meet our obligations under the agreements governing our indebtedness;
- the availability and cost of financing and refinancing our indebtedness;
- the amount of collateral required to be posted from time to time in our hedging transactions;
- our success in risk management activities, including the use of derivative financial instruments to hedge commodity and interest rate risks; and
- other risk factors discussed in the "Item 1A. Risk Factors" section of this annual report on Form 10-K.

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

PART I

Item 1. Business

General

We are a leading independent oil and gas exploration and production company focused on frontier and emerging areas in Africa and South America. Our asset portfolio includes existing production and other major project developments offshore Ghana, as well as exploration licenses with significant hydrocarbon potential offshore Mauritania, Morocco and Suriname and onshore Cameroon. Kosmos is listed on The New York Stock Exchange (“NYSE”) and is traded under the ticker symbol KOS.

Following our formation in 2003, we acquired multiple 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 in November 2010.

In the near-term, we are focused on maximizing production and cash flow from the Jubilee Field, 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 and development of our existing Ghana discoveries (Tweneboa, Enyenra, Ntomme and Wawa in the Deepwater Tano Block offshore Ghana (“DT Block”) and Mahogany, Teak and Akasa in the West Cape Three Points Block offshore Ghana (“WCTP Block”)). In the event of a declaration of commerciality and/or approval of a plan of development, we intend to develop these discoveries to grow proved reserves and production. During 2012, we submitted a declaration of commerciality and PoD over the Tweneboa, Enyenra and Ntomme (“TEN”) discoveries and are awaiting approval from the government of Ghana. 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 optimally developing our discoveries to initial production

We focus on the development of fields designed to deliver early learnings and production. There are numerous benefits to pursuing a phased development to support our production growth plan. Importantly, a phased development strategy can provide for first 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. 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 also refines the 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 recovery 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.

For example, first oil production from the Jubilee Field commenced in November 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.

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 initially focus. 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 and play types.

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 support and expand our asset portfolio.

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 the Jubilee Field has 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.

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

Kosmos is the operator of the WCTP Block and holds a 30.875% participating interest. The WCTP Petroleum Agreement ("WCTP PA"), which governs our activities related to the WCTP Block, and for commercial development areas, has a duration of 30 years from its effective date of July 22, 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, Mahogany and Teak) have not been relinquished, as the WCTP PA remains in effect after the end of the exploration phase for these areas while commerciality is being established. 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 Ghana National Petroleum Corporation ("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 to negotiate extends 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 Petroleum Agreement ("DT PA"), which governs our activities relating to the DT Block, and for commercial development areas, has a duration of 30 years from its effective date of July 19, 2006. The seven-year exploration phase of the DT PA expired in January 2013. Our existing discoveries within the DT Block (Tweneboa, Enyenra, Ntomme and Wawa) 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 for these areas while commerciality is being established. 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.

Our Ghanaian Discoveries

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

Discoveries	License	Kosmos Participating Interest	Block Operator(s)	Stage	Type	Expected Year of PoD Submission(10)
Ghana						
Jubilee Field Phase1(1)(2)	WCTP/DT(3)	24.0771%(5)	Tullow/Kosmos(6)	Production	Deepwater	2008(2)
Jubilee Field subsequent phases(1)(2)	WCTP/DT(3)	24.0771%(5)	Tullow/Kosmos(6)	Development	Deepwater	2011(7)
Mahogany	WCTP	30.8750%(4)	Kosmos	Development planning	Deepwater	2011(8)
Teak	WCTP	30.8750%(4)	Kosmos	Appraisal	Deepwater	2013
Akasa	WCTP	30.8750%(4)	Kosmos	Appraisal	Deepwater	2014
Tweneboa	DT	18.0000%(4)	Tullow	Appraisal	Deepwater	2012(9)
Enyenra	DT	18.0000%(4)	Tullow	Appraisal	Deepwater	2012(9)
Ntomme	DT	18.0000%(4)	Tullow	Appraisal	Deepwater	2012(9)
Wawa	DT	18.0000%(4)	Tullow	Appraisal	Deepwater	2014(10)

(1) For information concerning our estimated proved reserves in the Jubilee Field as of December 31, 2012, 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 in November 2010, and we received our first oil revenues in early 2011. For the other reservoirs within the Jubilee Unit, the Jubilee Full Field Development Plan ("JFFDP") was submitted to Ghana's Ministry of Energy for approval in December 2012, which contemplates future development of the Jubilee Field, although we can give no assurance that such approvals will be forthcoming in a timely manner or at all. 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 PA and 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 "UUOA") in July 2009 with GNPC and the other block partners of each of these two blocks. The UUOA governs the interests in and development of the Jubilee Field and created the Jubilee Unit from portions of the WCTP 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 participating interests in the Jubilee Field pursuant to the terms of the UUOA. 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 License Agreements—Jubilee Field Unitization." GNPC 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. Our paying interest on development activities in the Jubilee Field is 26.85484%.

(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 License 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. We submitted the JFFDP to Ghana's Minister of Energy in December 2012 and are awaiting approval from the government of Ghana. The JFFDP provides for future development of the Jubilee Field to be conducted through the Annual Work Plan and Budget Process, provided in the Jubilee UUOA.

(8) Mahogany, a combined area covering parts of the Mahogany East discovery and the Mahogany Deep discovery, 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. 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. We and the WCTP Block partners are in discussions with the Ministry of Energy and GNPC to resolve differences on the PoD.

(9) The DT Block partners submitted a declaration of commerciality and a PoD to Ghana's Ministry of Energy in November 2012 and are awaiting approval from the government of Ghana.

(10) In interpreting this information, 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" 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 participating 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."

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. Any party to the Jubilee UUOA with more than a 10% Jubilee Unit Interest may call for a second redetermination after December 1, 2013. 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 FPSO is designed to provide water and natural gas injection to support reservoir pressure and to process and store oil and natural gas. 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 "Kwame Nkrumah" 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 two existing producing reservoirs and development of the three remaining reservoirs to maximize ultimate recovery.

Production from the Phase 1 development commenced in November 2010, with Kosmos' first lifting in early 2011. As production from the field grew through 2011, certain near-wellbore productivity issues were identified, impacting several of the Phase 1 production wells. The Jubilee Unit partners identified a means of successfully mitigating the near-wellbore productivity issues experienced in the Jubilee production wells. To date, six wells have been successfully treated and additional stimulation treatments will be conducted as required. We have received an approval for the Phase 1A PoD of the Jubilee Field, with production from Phase 1A commencing in late 2012. The Phase 1A development is expected to include five additional production wells and three additional water injection wells and associated infrastructure.

Oil production from the Jubilee Field averaged approximately 72,000 barrels of oil per day during 2012 and we exited 2012 with production of approximately 110,000 barrels of oil per day. The JFFDP was submitted to the government of Ghana in December 2012. The JFFDP contemplates future development of the Jubilee Field, after Phase 1A, which will consist of infill drilling and development of the remaining Jubilee reservoirs. The JFFDP is anticipated to fully develop the field.

WCTP Block Discoveries

Mahogany 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.

Mahogany, a combined area covering parts of the Mahogany East discovery and the Mahogany Deep discovery, 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 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 Teak-4A appraisal well was completed in May 2012. The well encountered non-commercial reservoirs and accordingly was plugged and abandoned.

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.

Following additional appraisal and evaluation, a decision regarding the commerciality of these discoveries on the WCTP Block will be made by the WCTP 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. We expect that any future development of the WCTP Block discoveries would be a subsea tie-back through the Jubilee FPSO.

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, Enyenra-3A and Enyenra-4A wells have intersected multiple oil and natural gas condensate bearing reservoirs in a Turonian turbidite sequence. As of December 2012, drilling operations on the Enyenra-6A well have commenced and well results are expected in the first quarter of 2013. 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.

In November 2012, we submitted a declaration of commerciality and PoD over the TEN discoveries and are awaiting approval from the government of Ghana. Upon receiving approval, we anticipate commencing execution of the development plan, which is focused on an oil-based FPSO development.

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

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 to negotiate extends 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. Should a new petroleum agreement be entered into for the WCTP Relinquishment Area, we have identified prospects that have yet to be drilled on the WCTP Relinquishment Area.

DT Block

In December 2012, we spud the Sapele-1 exploration well. Drilling of the well was completed in February 2013. The well is not considered a productive well and accordingly will be plugged and abandoned. We and our DT Block partners have certain rights to negotiate a new petroleum contract with respect to the DT Relinquishment Area. We and our DT Block partners exercised such right in January 2012. Should a new petroleum agreement be entered into for the DT Relinquishment Area, we have identified prospects that have yet to be drilled on the DT Relinquishment Area.

Cameroon

We have two petroleum contracts in Cameroon, governing the Ndian River Block and adjoining Fako Block. These blocks are located within the Rio del Rey and Douala Basins. Kosmos is the operator of the Ndian River Block and Fako Block and holds a 100% participating interest in both blocks.

The Ndian River Block petroleum contract has a duration of up to 7 years from the November 2006 effective date with the current exploration period continuing into November 2013. We are in the first of two optional renewals, which was recently extended by one year, of the exploration period of our Ndian River Block, expiring in November 2013. The current exploration period carries a one-well obligation. In the event of commercial success, we have the right to develop and produce oil for a period of 20 years and gas for a period of 25 years from the grant of an exploitation authorization from the government, which may be extended for an additional period of 10 years under certain circumstances.

In January 2012, Kosmos entered into a license with the Republic of Cameroon for the Fako Block, which borders the southeast portion of our Ndian River Block in the Rio del Rey Basin. The Fako Block petroleum contract has an initial period of two years from the January 2012 effective date and may be extended into January 2018 at our election. In the event of commercial success, we have the right to develop and produce oil for a period of 20 years and gas for a period of 25 years from the grant of an exploitation authorization from the government, which may be extended for an additional period of 10 years under certain circumstances.

Kosmos has acquired gravity, magnetic and 2D seismic data over selected portions of our Cameroon licenses. Cameroon's producing basins lie south of the prolific Niger Delta in the Gulf of Guinea. The coastal area 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. The Ndian River Block and portions of the Fako Block are located in the Rio del Rey Basin. The Fako Block also extends south into the Douala Basin.

There are two primary play types on the Ndian River Block, the Isongo (Miocene) turbidite structural play and the Upper Cretaceous structural play. The Isongo turbidite structural play focuses on the Miocene aged turbidite reservoirs charged from the traditional Rio Del Rey Tertiary source rocks. We will test this play type with our Sipo-1 exploration well, which spud in February 2013. The Isongo reservoir fairway constitutes the primary reservoir in multiple other oil and gas discoveries to the south. The Sipo prospect is located onshore, in the southern part of the Ndian River Block. It is a large structurally trapped anticline associated with multiple stacked targets within the Miocene Isongo Formation. The Upper Cretaceous structural play targets Upper Cretaceous reservoirs charged from Cretaceous source rocks.

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, assessing the prospectivity for this license area.

Mauritania

In June 2012, Kosmos successfully acquired three new petroleum contracts offshore Mauritania. The new exploration licenses are Offshore Blocks C8, C12 and C13. Kosmos is the operator and holds a 90% participating interest in all blocks. The initial period of each contract is four years and may be extended to June 2022 at our election if certain requirements are met. Kosmos is currently in the first exploration period of the blocks, expiring in June 2016. In the event of commercial success, we have the right to develop and produce oil for 25 years and gas for 30 years from the grant of an exploitation authorization from the government, which may be extended for an additional period of 10 years under certain circumstances.

Offshore Blocks C8, C12 and C13 are located on the western margin of the proven petroleum system of the Mauritania Salt Basin. The blocks are adjacent to a proven petroleum system with the primary targets being Cretaceous sediments on structure and stratigraphic traps. Available geologic and geophysical data has led to the interpretation and mapping of possible Cretaceous basin floor fans outboard of the Salt Basin. The target prospects are basin floor fans over anticlinal structures. The Cretaceous source rocks penetrated by wells and typed to oils in the Mauritania Salt Basin are the same age as those which charge oil and gas fields throughout West Africa.

During the first half of 2013, the Company anticipates initiating a 2D seismic data acquisition program on approximately 6,000 line-kilometers, covering all three blocks. A 3D seismic program will be targeted for commencement in 2013. Information concerning prospects, if any, on such recently acquired license area is not yet available.

Morocco

During 2011, Kosmos acquired two new petroleum contracts, renewed an existing petroleum contract and acquired a new reconnaissance contract in Morocco. Our exploration licenses currently include the Cap Boujdour Offshore Block, which is within the Aaiun Basin, and the Essaouira Offshore Block and the 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 Cap Boujdour Offshore Block and has a 75% participating interest. We are currently in the first exploration period, which was recently extended to March 2014. The exploration phase may be extended up to eight years from the September 2011 effective date, or to September 2019. In the event of commercial success, we have the right to develop and produce oil or gas for a period of 25 years from the grant of an exploitation authorization from the government, which may be extended for an additional period of 10 years under certain circumstances.

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 distinct exploration fairways on this block, which provide substantial exploration opportunities. Based in part on a 3D seismic survey, we have been able to identify 20 prospects through trap identification, structural analysis, and depositional history mapping. The primary prospect types consist of well imaged Lower Cretaceous age slope channels and fans draped over anticlinal structures or in three-ways fault traps. The prospects exist in water depths varying from 1,000 to 3,000 meters. 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 Sahrawai Arab Democratic Republic."

Kosmos is the operator of the Foum Assaka Offshore Block. In October 2012, the Moroccan government issued a joint ministerial order approving our acquisition of an additional 18.75% participating interest in the Foum Assaka Offshore Block from Pathfinder Hydrocarbon Ventures, Ltd. ("Pathfinder"), a wholly owned subsidiary of Fastnet Oil and Gas plc ("Fastnet"), one of our block partners. Upon receipt of this order, we closed the acquisition of such additional participating interest with Pathfinder and have a 56.25% participating interest. We expect final governmental processes required to officially reflect the acquisition under Moroccan law to be completed in due course.

We are currently in the first exploration period, which is for two and one-half years from its effective date (July 1, 2011) ending in December 2013. The exploration phase may be extended to July 2019 at our election. In the event of commercial success, we have the right to develop and produce oil or gas for a period of 25 years from the grant of an exploitation authorization from the government, which may be extended for an additional period of 10 years under certain circumstances.

Kosmos is the operator of the Essaouira Offshore Block and has a 37.5% participating interest. We are currently in the first exploration period, which is for two and one-half years from its effective date (November 8, 2011) ending in May 2014. The exploration phase may be extended to November 2019 at our election. In the event of commercial success, we have the right to develop and produce oil or gas for a period of 25 years from the grant of an exploitation authorization from the government, which may be extended for an additional period of 10 years under certain circumstances.

During the first quarter of 2013, we closed an acquisition to acquire an additional 37.5% participating interest in the Essaouira Offshore Block from Canamens Energy Morocco SARL, one of our block partners. We expect final governmental processes required to officially reflect the acquisition under Moroccan law to be completed in due course. After giving effect to this acquisition, our participating interest in the Essaouira Offshore Block will be 75%.

In September 2012, as provided under the reconnaissance contract, we provided notification of intent to the *Office National des Hydrocarbures et des Mines* ("ONHYM") to enter into a petroleum contract for the Tarhazoute Offshore area. Negotiation of the petroleum contract and associated documents is currently ongoing. We anticipate we will be the operator of the block and will have a 75% participating interest. The Tarhazoute Offshore area is located offshore Morocco in the Agadir Basin between the Company's Essaouira and Foum Assaka Offshore Blocks.

The Foum Assaka Offshore Block, Essaouira Offshore Block and Tarhazoute Offshore area are located in the Agadir Basin. A working petroleum system has been established in the onshore area of the Agadir Basin based on onshore and shallow offshore wells. Well control, geological and geochemical studies suggest possible Cretaceous and Jurassic source rocks are located in the offshore Agadir Basin. The offshore Agadir Basin sediments are interpreted to comprise thick sequences of Lower to Upper Cretaceous age formations consisting of deep water channels and lobes. The interpreted prospects trapping styles are varied and include pre-salt ponded slope fans, salt domes, salt cored anticlines and sub-salt structures.

The Company has fulfilled the 3D seismic acquisition requirements for the Foum Assaka Offshore Block and Essaouira Offshore Block by acquiring approximately 4,900 square kilometers of 3D seismic data across the blocks. We are in process of interpreting the results of the newly acquired 3D seismc and pre-existing data, and may drill an exploration well as early as late 2013.

We are currently assessing prospectivity on our Agadir Basin acreage (Foum Asska, Essaouira and Tarhazoute) 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, to process seismic information to assess the prospectivity for these license areas.

Suriname

Kosmos has petroleum contracts covering Block 42 and Block 45 offshore Suriname. In November 2012, Kosmos finalized the assignment of a 50% participating interest in Block 42 and Block 45 to Chevron Global Energy Inc. ("Chevron") reducing its original interest from 100%. Kosmos retains a 50% participating interest in the blocks and remains the operator for the exploration phase of the petroleum contracts.

The initial period for Block 42 offshore Suriname is for 4 years from its effective date (December 12, 2011). The Block 42 exploration phase may be extended to December 2020 at our election. Kosmos is currently in the first exploration period ending on December 13, 2015. In the event of commercial success, the duration of the contract will be 30 years from the effective date or 25 years from governmental approval of a plan of development, whichever is longer.

The initial period for Block 45 offshore Suriname is for three years from its effective date (December 12, 2011). The Block 45 exploration phase may be extended to December 2018 at our election. Kosmos is currently in the first exploration period ending on December 13, 2014. In the event of commercial success, the duration of the contract will be 30 years from the effective date or 25 years from governmental approval of a plan of development, whichever is longer.

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.

During 2012, we completed a 3D seismic data acquisition program which covered approximately 3,900 square kilometers of portions of Block 42 and Block 45 offshore Suriname. The processing of this seismic data is expected to be completed in late 2013.

We believe the play types offshore Suriname are relatively similar to those offshore West Africa. We believe the subsurface underlying the deep water offshore Suriname may contain subtle stratigraphic traps similar to those discovered offshore Ghana in our Jubilee field. Target reservoirs are Upper and Middle Cretaceous age basin floor fans and mid-slope channel sands which may have good lateral continuity. The Tambaredjo and Calcutta Fields onshore Suriname prove that a working petroleum system exists in the area. Geological and geochemical studies suggest the hydrocarbons in these fields were generated in source rocks located over 100 miles offshore in the area of our petroleum contracts. The source rocks are believed to be the same ones which charged giant fields offshore West Africa. We are currently assessing prospectivity on our recently acquired license areas in 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, to process seismic information to assess the prospectivity for these license areas.

Our Reserves

The following table sets forth summary information about our estimated proved reserves as of December 31, 2012. See "Item 8. Financial Statements and Supplementary Data—Supplemental Oil and Gas Data (Unaudited)" for additional information.

All of our estimated proved reserves as of December 31, 2012, 2011 and 2010 were associated with our Jubilee Field in Ghana.

Summary of Oil and Gas Reserves

	2012 Net Proved Reserves(1)			2011 Net Proved Reserves(1)			2010 Net Proved Reserves(1)		
	Oil, Condensate, NGLs	Natural Gas(2)	Total	Oil, Condensate, NGLs	Natural Gas(2)	Total	Oil, Condensate, NGLs	Natural Gas(2)	Total
	(MMBbl)	(Bcf)	(MMBoe)	(MMBbl)	(Bcf)	(MMBoe)	(MMBbl)	(Bcf)	(MMBoe)
Reserves Category									
Proved developed	32	9	33	23	16	26	35	18	38
Proved undeveloped	10	1	10	25	8	26	17	4	18
	42	9	43	47	24	51	52	22	56

(1) As of December 31, 2012 and 2011, our unitized net interest is based on the 54.36660%/45.63340% redetermination split, between the WCTP Block and DT Block. As of December 31, 2010, our unitized net interest was based on the 50%/50% pre-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."

Changes for the year ending December 31, 2012, include a reclassification of 15 MMBbl of proved undeveloped reserves to proved developed reserves related to the successful remediation efforts in treating the near wellbore productivity issues on certain of the producing wells in the Jubilee Field and continued field developmental drilling in the Jubilee Field. Additional changes include a decrease of 14 Bcf in proved gas reserves due to a decrease in our estimate of fuel gas which will be utilized for operating the FPSO.

Changes for the year ending December 31, 2011, include an increase of 8 MMBbl 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 MMBbl 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.

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, 2012. All estimated future net revenues are attributable to projected production from the Jubilee Field in Ghana.

	Projected Net Revenues (in millions except $/Bbl)
Future net revenues	$ 2,612
Present value of future net revenues:	
PV-10(1)	$ 2,072
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)	$ 2,072
Benchmark and differential oil price($/Bbl)(3)	$112.61

(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 based on an average of the first-day-of-the-months throughout 2012 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 are a tax exempted

company incorporated pursuant to the laws of Bermuda and as the Company's intermediate subsidiaries positioned between it and the subsidiary that is a signatory to the WCTP and DT PAs continue to be tax exempted companies, we do not expect to be subject to future income tax expense related to our proved oil and gas reserves levied at a corporate parent or intermediate subsidiary level on future net revenues. Therefore, the year-end 2012 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 $111.21/Bbl for Dated Brent at December 31, 2012. 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 $1.40/Bbl premium relative to Dated Brent. This differential is utilized in our reserve estimates. The adjusted price utilized to derive the PV-10 is $112.61/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, 2012 are based on costs in effect at December 31, 2012 and the 12-month unweighted arithmetic average of the first-day-of-the-month price for the fiscal year ending December 31, 2012, 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.

For the years ended December 31, 2012, 2011 and 2010, 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, 2012 and related future net revenues and PV-10 at December 31, 2012 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, 2012 reserve report was completed on January 28, 2013, and a copy is included as an exhibit to this report.

In connection with the preparation of the December 31, 2012, 2011 and 2010 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, 2012, based upon its evaluation. NSAI's primary economic assumptions in estimates included an ability to sell oil at a price of $112.61/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 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 Resource Management System. 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 or geology. 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 the processes utilized in the development of our Resource Management System and reserve estimates on an annual basis. In addition, our technical services 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 review reserves and resource estimates on an annual basis.

License Areas

The following table sets forth certain information regarding the developed and undeveloped portions of our license areas as of December 31, 2012 for the countries in which we currently operate.

	Developed Area (Acres)		Undeveloped Area (Acres)		Total Area (Acres)	
	Gross	Net(1)	Gross	Net(1)	Gross	Net(1)
			(In thousands)			
Ghana						
Jubilee Unit	27.1	6.3	—	—	27.1	6.3
West Cape Three Points(2)	—	—	123.6	38.2	123.6	38.2
Deepwater Tano	—	—	190.1	34.2	190.1	34.2
Cameroon						
Ndian River	—	—	434.2	434.2	434.2	434.2
Fako	—	—	318.5	318.5	318.5	318.5
Mauritania						
Block C8	—	—	2,940.6	2,646.5	2,940.6	2,646.5
Block C12	—	—	1,748.3	1,573.4	1,748.3	1,573.4
Block C13	—	—	1,927.4	1,734.7	1,927.4	1,734.7
Morocco(3)						
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	899.7	1,599.5	899.7
Suriname						
Block 42	—	—	1,526.1	763.1	1,526.1	763.1
Block 45	—	—	1,266.7	633.3	1,266.7	633.3
Total	27.1	6.3	22,322.8	15,674.6	22,349.9	15,680.9

(1) Net acreage based on Kosmos' participating interest, before the exercise of any options or back-in rights. Our net acreage in Ghana 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. The WCTP "Undeveloped Area" reflected in the table above represents (i) acreage within three discovery areas (Teak, Akasa and Mahogany) that were not subject to relinquishment on the expiry of the exploration phase, (ii) the area relating to the Cedrela prospect, and (iii) the development and production area relating to the Mahogany PoD. The "Undeveloped Area" does not include the Banda discovery area which was relinquished in January 2013 as we do not consider this discovery to be commercially viable. The Mahogany PoD is the subject of a Notice of Dispute with the Ministry of Energy and GNPC and is currently under discussion between the WCTP Block partners, GNPC and the Ministry of Energy (see "—Our Ghanaian Discoveries—WCTP Block Discoveries"). The Cedrela prospect was to be drilled by the Cedrela-1 exploration well; but 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 between 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 Essaouria Offshore and Foum Assaka Offshore Blocks. In September 2012, Kosmos provided notification of intent to the Moroccan government to enter into a petroleum contract for the Tarhazoute Offshore area. Negotiation of the petroleum contract and associated documents is currently ongoing.

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	Total
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Net	Gross
Year Ended December 31, 2012														
Ghana														
Jubilee Unit	—	—	—	—	—	—	5	1.20	—	—	5	1.20	1.20	5
West Cape Three Points	—	—	1	0.31	1	0.31	—	—	—	—	—	—	0.31	1
Deepwater Tano	—	—	1	0.18	1	0.18	—	—	—	—	—	—	0.18	1
Total	—	—	2	0.49	2	0.49	5	1.20	—	—	5	1.20	1.69	7
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
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

(1) As of December 31, 2012, 20 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 producing well. Productive wells are included in the table in the year they were determined to be productive, as opposed to the year the well was drilled.

(3) A dry well is an exploratory or development well that is not a productive well. Dry wells are included in the table in the year they were determined not to be a productive well, as opposed to the year the well was drilled.

The following table shows the number of wells that are in the process of being drilled or are in active completion stages, and the number of wells suspended or waiting on completion as of December 31, 2012. The following table does not include the Sipo-1 exploration well on the Ndian River Block in Cameroon which spud in February 2013.

	Actively Drilling or Completing				Wells Suspended or Waiting on Completion			
	Exploration		Development		Exploration		Development	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Ghana								
Jubilee Unit	—	—	1	0.24	—	—	3	0.72
West Cape Three Points	—	—	—	—	8	2.47	—	—
Deepwater Tano	1	0.18	—	—	12	2.16	—	—
Total	1	0.18	1	0.24	20	4.63	3	0.72

Undeveloped license area expirations

The WCTP PA has a duration of 30 years from its effective date (July 2004); however, in July 22, 2011, at the end of the seven-year exploration phase, the WCTP Relinquishment Area was subject to relinquishment. We maintain rights to our three existing discoveries within the WCTP Block (Akasa, Mahogany and Teak) as the WCTP PA remains in effect after the end of the exploration phase. 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 for 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 to negotiate extends 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.

Mahogany, a combined area covering parts of the Mahogany East discovery and the Mahogany Deep discovery, 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 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, as Operator and 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 expired 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, Ntomme and Wawa. The DT Block partners submitted a declaration of commerciality and PoD for the TEN discoveries to Ghana's Ministry of Energy on November 6, 2012. Evaluation and appraisal activities continue on the Wawa discovery. 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 peteroleum 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. On September 7, 2012, we applied to Cameroon's Minister of Industry, Mines and Technology Development for a one-year extension of the first renewal period, which was granted in an order dated October 11, 2012. The current exploration period now ends on November 20, 2013.

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 License Agreements

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

West Cape Three Points Block

Effective July 22, 2004, Kosmos, the EO Group and GNPC entered into the WCTP PA covering the WCTP Block offshore Ghana in the Tano Basin. As a result of farm-out agreements and other sales of partners interests for the WCTP Block, Kosmos, Anadarko WCTP Company ("Anadarko"), Tullow and Sabre Oil and Gas Limited ("Sabre"), a wholly owned subsidiary of Petro S.A., 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. GNPC has the option to acquire additional paying interests in a commercial discovery on the WCTP Block of 2.5%. 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. 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 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.

Due to contractual relinquishments at the end of contract periods, the WCTP Block currently comprises areas that are part of our existing discoveries (Akasa, Mahogany and Teak) in the WCTP Block as well as the Cedrela prospect area, or approximately 123,635 acres (500 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 exploration phase of the WCTP PA has expired and 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. As a result of farm-out agreements and other sales of partners interests for the DT Block, Kosmos, Anadarko, Tullow and Sabre's participating interests are 18%, 18%, 49.95% and 4.05%, respectively. Tullow is the operator. GNPC has a 10% participating interest and will be carried through the exploration and development phases. GNPC has the option to acquire additional paying interests in a commercial discovery on the DT Block of 5%. 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. 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.

Due to contractual relinquishments at the end of contract periods, the DT Block currently 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. We are currently in the second extension period of the exploration phase of the DT PA, which expired in January 2013. All commitments under the extension period were fulfilled by drilling exploration wells on the DT Block in December 2012.

After the expiration of the exploration phase, the DT Block will comprise areas that are part of our existing discoveries in the DT Block. 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.

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. A Pre Unit Agreement was agreed to between the contractors groups of the WCTP and DT Blocks in 2008, with a more comprehensive unit agreement, the UUOA, agreed to in 2009 which govern each party's respective rights and duties in the Jubilee Unit. Tullow is the Unit Operator, while Kosmos is the Technical Operator for Development of the Jubilee Unit. The Jubilee Unit holders' interests are subject to redetermination in accordance with the terms of the UUOA. 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 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%. The accounting for the Jubilee Unit is in accordance with the redetermined tract participation stated. Although the Jubilee Field is unitized, Kosmos' participating interests in each block outside the boundary of the Jubilee Unit remains the same. Kosmos remains operator of the WCTP Block outside the Jubilee Unit area.

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 is responsible for drilling and completing the development wells for the Jubilee Field 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 and subsequent phases. 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.

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. The JFFDP was submitted to Ghana's Minister of Energy in December 2012.

Ndian River Block

On December 19, 2006, Kosmos signed the Ndian River petroleum 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") has the option to back into the contract with an interest of up to 15% upon approval of a PoD. The Ndian River petroleum 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 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 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. On September 16, 2010, in accordance with the terms of the Ndian River petroleum 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. On September 7, 2012, we applied to Cameroon's Minister of Industry, Mines and Technology Development for a one-year extension of the first renewal period, which was granted in an order dated October 11, 2012. The current exploration period now ends on November 20, 2013.

The Sipo-1 exploration well on the Ndian River Block spud in February 2013.

Sales and Marketing

Production from the Jubilee Field began in November 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. 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 our stakeholders that we will be able to successfully compete when attempting to make further strategic acquisitions.

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 Sahrawai 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 commence;
- enjoin some or all of the operations or facilities deemed not in compliance with permits;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling, production and transportation activities;

- limit or prohibit drilling activities in certain locations lying within protected or otherwise sensitive areas; and
- require remedial measures to mitigate or remediate pollution, including pollution resulting from our operations.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. Compliance with these laws can be costly; the regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. We cannot assure you that we have been or will be at all times in compliance with such laws, or that environmental laws and regulations will not change or become more stringent in the future in a manner that could have a material adverse effect on our financial condition and results of operations.

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

For example, the Macondo spill in the Gulf of Mexico (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 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, restrict or prevent our operations in those countries.

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 OSCPs, emergency response teams may be activated to respond to oil spill incidents. We maintain a tiered response system for the mobilization of resources depending on the severity of an incident. 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 would engage the services of Oil Spill Response Limited ("OSRL") of Southampton, United Kingdom, an oil spill response contractor.

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

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, 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 participating interest in the block incurred as a result of pollution and environmental damage, containment and clean-up activities, loss or damage to any well, loss of oil or natural gas resulting from a blowout, crater, fire, or uncontrolled well, loss of stored oil and natural gas, and liabilities incurred in connection with plugging or bringing under control any well. We maintain insurance coverage typical of the industry in the areas we operate in, these include; property damage insurance, loss of production insurance, wreck removal insurance, control of well insurance, general liability including pollution liability to cover pollution from wells and other operations. We also participate in an insurance coverage program for the Jubilee FPSO. Our insurance is carried in amounts typical for the industry and relative to our size and operations and in accordance with our contractual and regulatory obligations.

Other Regulation of the Oil and Gas Industry

Ghana

The Ghanaian Petroleum Law currently governs the upstream Ghanaian oil and natural gas regulatory regime and sets out the policy and framework for industry participants. All petroleum found in its natural state within Ghana is deemed to be national property and is to be developed on behalf of the people of Ghana. GNPC is empowered to carry out exploration and development work either on its own or in association with local or foreign contractors. Companies who wish to gain rights to explore and produce in Ghana can only do so by entering into a petroleum agreement with 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 executive capacity. The Petroleum Commission is the regulatory body for the upstream petroleum industry and the advisor to the Ministry of Energy. GNPC has rights to undertake petroleum operations in any acreage declared open by Ghana's Ministry of Energy. As well, when petroleum operations are undertaken by GNPC in association with contracts, GNPC has a carried interest in each petroleum agreement and, following the declaration of any commercial discovery, such carried interest is typically subject to increase by a certain agreed upon amount at the option of GNPC. Petroleum agreements are required to include certain domestic supply requirements, including the sale to Ghana of oil for consumption in Ghana at international market prices.

The Ghanaian Petroleum Exploration and Production Act 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 Exploration and Production Act 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 of 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 appraisal plans, field development plans, recommending to the Minister national policies related to petroleum, and storing and managing data. We understand the primary purpose of the Petroleum Commission is to fulfill the regulatory functions previously undertaken by GNPC. We currently believe that such laws will only have prospective application, and as such will not modify the terms of (or interests under) the agreements governing our license interests in Ghana, including the WCTP and DT 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." Ghana's Parliament is also considering the enactment of Petroleum (Local Content and Local Participation in Petroleum Activities) Regulations. Industry comments have been submitted.

Cameroon

In 1999 and 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 into a petroleum contract with the Republic of 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 the Minister in charge of Hydrocarbons.

Mauritania

The main legislative acts in the Islamic Republic of Mauritania (State) relevant to petroleum exploration and production are Law No. 2010-033 dated July 20, 2010 and its amendment ("Hydrocarbon Laws"). The regulatory authority in Mauritania is the Ministry of Petroleum, Energy and Mines and the national oil company acting on its behalf is the Mauritanian Society of Hydrocarbons ("SMH"). SMH was instituted by Decree No. 2005-106 of November 7, 2005 and modified by Decree No. 2009-168 of May 3, 2009. Pursuant to Hydrocarbon Laws the State or SMH may undertake petroleum operations and may authorize other legal entities to undertake petroleum operations under exploration-production contracts ("PSC"). The Ministry shall sign PSCs on behalf of the State. The exploration period shall not be more than ten years, subject to certain permitted extensions and the exploitation period shall not be more than 25 years. Each PSC may provide that the State has a carried interest of up to 10% during the exploration period. Each PSC shall grant the State the option to participate for a percentage not less then 10% in the rights of the Contractor during the exploitation period.

Morocco

The two main legislative acts in Morocco relevant to petroleum exploration and production are (i) the Law 21-90 (April 1, 1992) as amended and completed by the Law 27-99 (February 15, 2000) and (ii) the Decree 2-93-786 (November 3, 1993) as amended and completed by decree 2-99-210 (March 16, 2000) (together, "Morocco's Petroleum Laws"). The regulatory authority in Morocco is the Ministry of Energy, Mines, Water and Environment and the national oil company acting on his behalf is ONHYM. ONHYM is a public establishment (*établissement public*) with the legal personality and financial autonomy created pursuant to the Law 33-01 (November 11, 2003) which was further completed by the Decree 2-04-372 (December 29, 2004).

Pursuant to the Law 21-90, 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 Sahrawai 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 Sahrawai 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.

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, 2012, we had approximately 250 employees. None of these employees are represented by labor unions or covered by any collective bargaining agreement. We believe that relations with our employees are satisfactory.

Corporate Information

We were incorporated pursuant to the laws of Bermuda as Kosmos Energy Ltd. in January 2011 to become a holding company for Kosmos Energy Holdings. Kosmos Energy Holdings was formed as an exempted company limited by guarantee pursuant to the laws of the Cayman Islands in March 2004. Pursuant to the terms of a corporate reorganization that was completed simultaneously with the closing of our 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.

Available Information

Kosmos is listed on the NYSE and our common shares are traded under the symbol “KOS”. We file or furnish annual, quarterly and current reports, proxy statements and other information with the SEC. The public may read and copy any reports, statements or other information at the SEC’s Public

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

The Company also maintains an internet website under the name *www.kosmosenergy.com*. The information on our website is not incorporated by reference into this annual report on Form 10-K and should not be considered a part of this annual report on Form 10-K. Our website is included as an inactive technical reference only. We make available, free of charge, on our website, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after such reports are electronically filed with, or furnished to, the SEC.

Item 1A. Risk Factors

You should consider and read carefully all of the risks and uncertainties described below, together with all of the other information contained in this report, including the consolidated financial statements and the related notes included in "Item 8. Financial Statements and Supplementary Data." If any of the following risks actually occurs, our business, business prospects, financial condition, results of operations or cash flows could be materially adversely affected. The risks below are not the only ones we face. Additional risks not currently known to us or that we currently deem immaterial may also adversely affect us.

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

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

We have limited proved reserves. 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. Many of our current discoveries and all of our prospects are in various stages of evaluation that will require substantial additional analysis and interpretation. Even when properly used and interpreted, 2D and 3D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. Accordingly, we do not know if any of our discoveries or prospects will contain oil or natural gas in sufficient quantities or quality to recover drilling and completion costs or to be economically viable. Even if oil or natural gas is found on our discoveries or prospects in commercial quantities, construction costs of gathering lines, subsea infrastructure and floating production systems and transportation costs (or analogous developmental costs associated with onshore production in the case of our onshore licenses) 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, Suriname and Mauritania licenses 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, 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.

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, any identified prospects within the WCTP Relinquishment Area 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 January 2012. 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, any identified prospects within the DT Relinquishment Area 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 licenses in Cameroon, the current exploration period for the Ndian River license will expire on November 20, 2013. Kosmos is required to drill one well before the expiration of this renewal period (such requirement to be certified by the Sipo-1 exploration well which spud in February 2013). Failure to do so may result in our loss of the license. The initial exploration period for the Fako Block will expire on January 13, 2014. Under this petroleum contract, we have work commitments to perform exploration activities and other related activities. Failure to do so may result in our loss of the license.

We are currently in the initial exploration phase for our petroleum contracts in Mauritania, with such phases of the Offshore Blocks C8, C12 and C13 expiring in June 2016. Under these petroleum contracts, we have work commitments to perform exploration activities and other related activities. Failure to do so may result in our loss of the licenses.

We are currently in the initial exploration phase for our petroleum contracts in Morocco, with such phases of the Cap Boujdour Offshore Block, Essaouira Offshore Block, and the Foum Assaka Offshore Block expiring on March 1, 2014, April 21, 2014, and January 1, 2014, respectively. Under these petroleum contracts, we have work commitments to perform exploration and other related activities. Failure to do so may result in our loss of the license. We are currently negotiating the terms of the petroleum agreement which will govern the Tarhazante Block.

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 seismic; acquire, process and interpret seismic data; 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 and reprocess seismic data. Failure to complete such requirements may result in our loss of these licenses.

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—Operations by Geographic Area."

The inability of one or more third parties who contract with us to meet their obligations to us may adversely affect our financial results.

We may be liable for certain costs if third parties who contract with us are unable to meet their commitments under such agreements. We are currently exposed to credit risk through joint interest receivables from our block and/or unit partners. If any of our partners in the blocks or unit in which we hold interests are unable to fund their share of the exploration and development expenses, we may be liable for such costs. In the past, certain of our WCTP and DT Block partners have not paid their share of block costs in the time frame required by the joint operating agreements for these blocks. This has resulted in such party being in default, which in return requires Kosmos and its non-defaulting block partners to pay their proportionate share of the defaulting party's costs during the default period. Should a default not be cured, Kosmos could be required to pay its share of the defaulting party's costs going forward.

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 counterparties to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. In addition, our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. Joint interest receivables arise from our block partners. The inability or failure of third parties we contract with to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

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 1, 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 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.

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, 2012.

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.

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, 2012 would each decrease by approximately $18.3 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 may need to raise substantial additional capital, through additional debt financing, strategic alliances or future private or public equity offerings if our cash flows from operations are not sufficient to cover such costs.

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

- the scope, rate of progress and cost of our exploration, appraisal, development and production activities;
- oil and natural gas prices;
- our ability to locate and acquire hydrocarbon reserves;
- our ability to produce oil or natural gas from those reserves;
- the terms and timing of any drilling and other production-related arrangements that we may enter into;
- the cost and timing of governmental approvals and/or concessions; and
- the effects of competition by larger companies operating in the oil and gas industry.

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

Assuming we are able to commence exploration, appraisal, development and production activities or successfully exploit our licenses during the exploratory term, our interests in our licenses (or the development/production area of such licenses as they existed at that time, as applicable) could extend beyond 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 or man-made disasters;
- technological advances affecting energy consumption;
- governmental regulations and taxation policies;
- proximity and capacity of transportation facilities;
- the price and availability of competitors' supplies of oil and natural gas; and
- the price, availability or mandated use of alternative fuels.

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.

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 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 construction of the pipeline and onshore plant has not been completed. 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 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'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;

- uncontrolled flows or leaks of oil, well fluids, natural gas, brine, toxic gas or other pollutants or hazardous materials;
- gas flaring operations;
- marine hazards with respect to offshore operations;
- formations with abnormal pressures;
- pollution, other environmental risks, and geological problems; and
- weather conditions and natural or man-made disasters.

These risks are particularly acute in deepwater drilling and exploration. Any of these events could result in loss of human life, significant damage to property, environmental or natural resource damage, impairment, delay or cessation of our operations, 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.

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, the DT PA and the UUOA cover the two blocks and the Jubillee Unit that form the basis of our current 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. The resolution of certain of these disagreements required us to pay agreed settlement costs to GNPC and/or the government of Ghana.

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. 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 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, natural or man-made disasters or acts of God;
- delays or decreases in production, the availability of equipment, facilities, personnel or services;
- delays or decreases in the availability of capacity to transport, gather or process production; and/or
- military conflicts or civil unrest.

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 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, Mauritania, 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.

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

Furthermore, various activist groups have mounted public relations campaigns to force companies to cease and divest operations in Western Sahara, and we could come under similar public pressure. Some investors have refused to invest in companies with operations in Western Sahara, and we could be subject to similar pressure. Any of these factors could have a 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.

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 those related to remediation, investigation or permitting.

Under these and other laws and regulations, we could be liable for personal injuries, property damage and other types of damages. Failure to comply with these laws and regulations also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws and regulations could change, or their interpretations could change, in ways that could substantially increase our costs. These risks may be higher in the developing countries in which we conduct 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 affect on our business. We also cannot assure you that government approval will not be needed for direct or indirect transfers of our petroleum agreements or interests thereunder based on existing legislation. See “Item 1. Business—Other Regulation of the Oil and Gas Industry—Ghana.”

The SEC recently promulgated final rules under the Dodd-Frank Act requiring SEC reporting companies that engage in the commercial development of oil, natural gas or minerals, to disclose payments (including taxes, royalties, fees and other amounts) made by such companies or an entity controlled by such companies to the United States or to any non-U.S. government for the purpose of commercial development of oil, natural gas or minerals. Such disclosure will be made in a new public filing with the SEC starting in 2014 (and will cover the 2013 calendar year). The final rules do not contain an exception that would allow companies to exclude payments which may not be disclosed pursuant to foreign laws or confidentiality agreements. Accordingly, while we are working with our foreign partners and the governments of the foreign jurisdictions in which we conduct our oil and gas operations in preparation for these new reporting obligations, there can be no assurance that we will be able to comply with these regulations without creating disagreements with these partners or governments. Further, such regulations may place us at a disadvantage to our non-U.S. competitors in doing business in the international oil and gas industry. Any of these consequences could have a material adverse effect on our financial condition and our results of operations.

We 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, transportation and disposal of regulated materials and the health and safety of our employees. We are required to obtain environmental permits from governmental authorities for our operations, including drilling permits for our wells. We have not been or may not be at all times in complete compliance with these permits and the environmental and health and safety laws and regulations to which we are subject, and there is a risk such requirements could change in the future or become more stringent. If we violate or fail to comply with such requirements, we could be fined or otherwise sanctioned by regulators, including through the revocation of our permits or the suspension or termination of our operations. If we fail to obtain, maintain or renew permits in a timely manner or at all (due to opposition from partners, community or environmental interest groups, governmental delays or 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, maintain or renew permits or such changes in or enactment of laws or regulations could impede or affect our operations, which could have a material adverse effect on our results of operations and financial condition.

We, as an interest owner or as the designated operator of certain of our past, current and future discoveries and prospects, could be held liable for some or all environmental, health and safety costs and liabilities arising out of our actions and omissions as well as those of our block partners, third-party contractors, predecessors or other operators. To the extent we do not address these costs and liabilities or if we do not otherwise satisfy our obligations, our operations could be suspended or terminated. We have contracted with and intend to continue to hire third parties to perform services related to our operations. There is a risk that we may contract with third parties with unsatisfactory environmental, health 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 other event occurs and is not covered by insurance, such accident or event could have a material adverse effect on our results of operations and financial condition.

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

In addition, we expect continued and increasing attention to climate change issues. Various countries and regions have agreed to regulate emissions of greenhouse gases ("GHGs"), including methane (a primary component of natural gas) and carbon dioxide (a byproduct of oil and natural gas combustion). The regulation of GHGs or any treaty or other arrangement adopted with respect to climate change by any of the areas in which we, our customers and the end-users of our products operate may increase our compliance costs, such as for monitoring, sequestering 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. The physical impacts of climate change in the areas in which we operate, including through increased severity and frequency of storms, floods and other weather events, could adversely impact our operations or disrupt transportation or other process-related services provided by our third-party contractors.

Environmental, health and safety laws are complex, change frequently and have tended to become increasingly stringent over time. Our costs of complying with current and future climate change, environmental, health and safety laws, the actions or omissions of our block partners and third party contractors and our liabilities arising from releases of, 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 for FCPA violations committed by companies in which we invest in (for example, by way of acquiring equity interests in, participating as a joint venture partner with, acquiring the assets of, or entering into certain commercial transactions with) or that we acquire.

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.

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

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

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

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

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

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

Our commercial debt facility and revolving credit facility include certain covenants that, among other things, restrict:

- our investments, loans and advances and certain of our subsidiaries' payment of dividends and other restricted payments;
- our incurrence of additional indebtedness;
- the granting of liens, other than liens created pursuant to the commercial debt facility and revolving credit 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 and revolving credit facility.

Our commercial debt facility and revolving credit facility require us to maintain certain financial ratios, such as debt service coverage ratios and cash flow coverage ratios. All of these restrictive covenants may limit our ability to expand or pursue our business strategies. Our ability to comply with these and other provisions of our commercial debt facility and revolving credit 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 and revolving credit 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 and revolving credit 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 under our commercial debt facility and revolving credit 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.

At December 31, 2012, we had $1.0 billion outstanding and $500.0 million of committed undrawn capacity under our commercial debt facility, of which $340.4 million was available. As of December 31, 2012, we had zero outstanding and $260.0 million of committed undrawn capacity under the revolving credit facility, all of which 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.

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

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

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

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

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

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

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

The Bermuda Minister of Finance, under the Exempted Undertakings Tax Protection Act 1966 of Bermuda, as amended, has given us an assurance that if any legislation is enacted in Bermuda that would impose tax computed on profits or income, or computed on any capital asset, gain or appreciation, or any tax in the nature of estate duty or inheritance tax, then the imposition of any such tax will not be applicable to us or any of our operations, shares, debentures or other obligations until March 31, 2035, except insofar as such tax applies to persons 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, and its implementing regulations, could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price and other risks associated with our business.

We use derivative instruments to manage our commodity price and interest rate risk. The United States Congress adopted comprehensive financial reform legislation in 2010 that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as ours, that participate in that market. The 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. Many of the provisions of the Dodd-Frank Act require implementing regulations by agencies including the Commodity Futures Trading Commission (the "CFTC") and the SEC. The adopting and implementation of these regulations is underway but has not yet been completed.

Of particular importance to us, the CFTC has the authority to, under certain findings, establish position limits for certain futures, options on futures and swap contracts. Certain bona fide hedging transactions or positions would be exempt from these position limits. The CFTC adopted final position limit rules for 28 physical commodity contracts and related futures, options on futures and swaps on November 18, 2011, but these rules were vacated by the United States District Court for Columbia on September 28, 2012 after a lawsuit was brought by market participants. The CFTC has authorized an appeal, and it is unclear when these rules or similar rules might come into effect. Depending on the final form of any such rules, they may affect our ability to cost-effectively hedge our commodity risks.

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. While there are likely to be exceptions from many of these requirements for commercial end users of derivatives like us, the final contours of many of these exceptions, and whether we choose to use them, is uncertain at this time. The Dodd-Frank Act and its implementing regulations may also require the counterparties to our derivative instruments to register with the CFTC and become subject to substantial regulation or even spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. These requirements and others could significantly increase the cost of derivatives contracts (including through requirements to clear swaps and to post collateral, each of which could adversely affect our available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Our revenues could also be adversely affected if a consequence of the legislation and regulations is to lower commodity prices.

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

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

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. This lawsuit has been removed from the Dallas County State court in which it was originally filed to the United States Federal District Court for the Northern District of Texas, Dallas Division and has been consolidated along with three substantially similar lawsuits into one 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;
- 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 or sale of any additional securities of ours;
- investor perception of our company and of the industry in which we compete; and
- general economic, political and market conditions.

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

All of the shares sold in our 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 (unless they have been sold pursuant to Rule 144 to date). Restricted securities may be sold in the U.S. public market only if registered or if they qualify for an exemption from registration, including by reason of Rule 144 or Rule 701 under the Securities Act. All of our restricted shares are eligible for sale in the public market, subject in certain circumstances to the volume, manner of sale limitations with respect to shares held by our affiliates and other limitations under Rule 144. Additionally, we have registered all our common shares that we may issue under our employee benefit plans. These shares can be freely sold in the public market upon issuance, unless pursuant to their terms these share awards have transfer restrictions attached to them. Sales of a substantial number of our common shares, or the perception in the market that the holders of a large number of shares intend to sell common shares, could reduce the market price of our common shares.

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 65% of our issued and outstanding common shares. Consequently, these shareholders have significant influence over all matters that require approval by our shareholders, including the election of directors and approval of significant corporate transactions. This concentration of ownership will limit your ability to influence corporate matters, and as a result, actions may be taken that you may not view as beneficial.

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

We may issue additional common shares, preferred shares, warrants, rights, units and debt securities for general corporate purposes, including, but not limited to, repayment or refinancing of borrowings, working capital, capital expenditures, investments and acquisitions. We continue to actively seek to expand our business through complementary or strategic acquisitions, and we may issue additional common shares in connection with those acquisitions. We also issue restricted shares to our executive officers, employees and independent directors as part of their compensation. If we issue additional common shares in the future, it may have a dilutive effect on our current outstanding shareholders.

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

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

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

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

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

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

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

We are a Bermuda exempted company. As a result, the rights of holders of our common shares will be governed by Bermuda law and our memorandum of association and bye-laws. The rights of shareholders under Bermuda law may differ from the rights of shareholders of companies incorporated in other jurisdictions. 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 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 17 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 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. This lawsuit has been removed from the Dallas County State court in which it was originally filed to the United States Federal District Court for the Northern District of Texas, Dallas Division and has been consolidated along with three substantially similar lawsuits into one 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 Disclosures

Not applicable.

PART II

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

Common Shares Trading Summary

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

	2012		2011	
	High	Low	High	Low
First Quarter	$15.13	$12.30	$ N/A	$ N/A
Second Quarter	13.70	10.03	19.70	16.49
Third Quarter	11.75	8.19	17.40	10.61
Fourth Quarter	12.65	9.55	16.55	10.10

As of February 18, 2013, 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 221. On February 18, 2013, the last reported sale price of Kosmos' common shares, as reported on the NYSE, was $10.61 per share.

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

Issuer Purchases of Equity Securities

In May 2012, we purchased 0.8 million common shares for $8.4 million from certain of our employees pursuant to net share settlement arrangements in our long-term incentive plan in order to facilitate withholding tax payments upon the vesting of equity awards granted under the plans.

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.

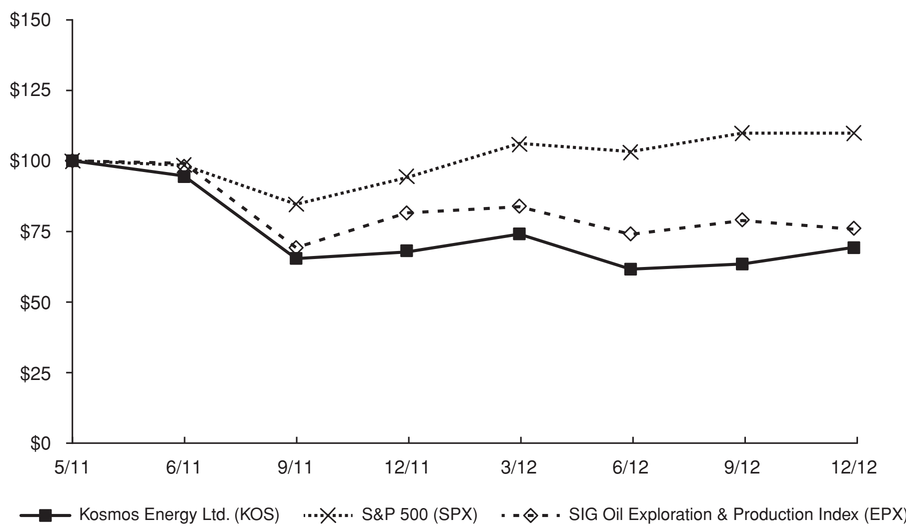
There has been no material change in our planned use of proceeds from the IPO from that described in our final prospectus dated May 10, 2011 and filed with the SEC pursuant to Rule 424(b).

During 2012, we used net proceeds to repay indebtedness under our Facility and for exploration activities and 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.

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, 2012, in cumulative total stockholder return on our common shares as measured against the cumulative total return of the S&P 500 Index and the SIG Oil Exploration & Production Index. The graph tracks the performance of a $100 investment in our common shares and in each index (with the reinvestment of all dividends).



		December 31,	
	May 11, 2011	2011	2012
Kosmos Energy Ltd. (KOS)	$100.00	$68.11	$ 68.61
S&P 500 (SPX)	100.00	94.04	109.09
SIG Oil Exploration & Production Index (EPX)	100.00	81.40	75.76

Item 6. Selected Financial Data

The following selected consolidated financial information set forth below as of and for the five years ended, December 31, 2012, should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data."

Consolidated Statements of Operations Information:

	Years Ended December 31,				
	2012	2011(1)	2010	2009	2008
	(In thousands, except per share data)				
Revenues and other income:					
Oil and gas revenue	$667,951	$666,912	$ —	$ —	$ —
Interest income	1,108	9,093	4,231	985	1,637
Other income	3,150	775	5,109	9,210	5,956
Total revenues and other income	672,209	676,780	9,340	10,195	7,593
Costs and expenses:					
Oil and gas production	95,109	83,551	—	—	—
Exploration expenses	97,712	126,409	73,126	22,127	15,373
General and administrative	160,027	113,579	98,967	55,619	40,015
Depletion, depreciation and amortization	185,707	140,469	2,423	1,911	719
Amortization—deferred financing costs	8,984	16,193	28,827	2,492	—
Interest expense	52,207	65,749	59,582	6,774	1
Derivatives, net	31,490	11,777	28,319	—	—
Loss on extinguishment of debt	5,342	59,643	—	—	—
Doubtful accounts expense	—	(39,782)	39,782	—	—
Other expenses, net	1,475	149	1,094	46	21
Total costs and expenses	638,053	577,737	332,120	88,969	56,129
Income (loss) before income taxes	34,156	99,043	(322,780)	(78,774)	(48,536)
Income tax expense (benefit)	101,184	76,686	(77,108)	973	269
Net income (loss)	$(67,028)	$ 22,357	$(245,672)	$ (79,747)	$(48,805)
Accretion to redemption value of convertible preferred units	—	(24,442)	(77,313)	(51,528)	(21,449)
Net loss attributable to common shareholders/unit holders	$(67,028)	$ (2,085)	$(322,985)	$(131,275)	$(70,254)
Net income (loss) per share attributable to common shareholders (the year ended December 31, 2011 represents the period from May 16, 2011 to December 31, 2011)(2):					
Basic	$ (0.18)	$ 0.09			
Diluted	$ (0.18)	$ 0.09			
Weighted average number of shares used to compute net income (loss) per share (the year ended December 31, 2011 represents the period from May 16, 2011 to December 31, 2011)(2):					
Basic	371,847	368,474			
Diluted	371,847	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 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) For the year ended December 31, 2011, we have presented net income (loss) per share attributable to common shareholders (including weighted average number of shares used to compute net income (loss) per share attributable to common shareholders) from the date of our corporate reorganization, May 16, 2011, to December 31, 2011. Net income for the period from May 16, 2011 through December 31, 2011 was $36.1 million. For the periods presented prior to our corporate reorganization, we do not calculate historical net income (loss) per share attributable to common shareholders because we did not have a common unit of ownership in those periods.

Consolidated Balance Sheets Information:

	As of December 31,				
	2012	2011	2010	2009	2008
			(In thousands)		
Cash and cash equivalents	$ 515,164	$ 673,092	$ 100,415	$ 139,505	$ 147,794
Total current assets	750,118	1,112,481	559,920	256,728	205,708
Total property and equipment, net	1,525,762	1,377,041	998,000	604,007	208,146
Total other assets	90,243	62,412	133,615	161,322	1,611
Total assets	2,366,123	2,551,934	1,691,535	1,022,057	415,465
Total current liabilities	190,253	339,607	482,057	139,647	68,698
Total long-term liabilities	1,146,964	1,191,601	845,383	287,022	444
Total convertible preferred units	—	—	978,506	813,244	499,656
Total shareholders' equity/unit holdings equity	1,028,906	1,020,726	(614,411)	(217,856)	(153,333)
Total liabilities, convertible preferred units and shareholders' equity/unit holdings equity	2,366,123	2,551,934	1,691,535	1,022,057	415,465

Consolidated Statements of Cash Flows Information:

	Years Ended December 31,				
	2012	2011	2010	2009	2008
			(In thousands)		
Net cash provided by (used in):					
Operating activities	$ 371,530	$ 364,909	$ (191,800)	$ (27,591)	$ (65,671)
Investing activities	(402,662)	(385,140)	(589,975)	(500,393)	(156,882)
Financing activities	(126,796)	592,908	742,685	519,695	331,084

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 a leading independent oil and gas exploration and production company focused on frontier and emerging areas in Africa and South America. Our asset portfolio includes existing production and other major project developments offshore Ghana, as well as exploration licenses with significant hydrocarbon potential offshore Mauritania, 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.

Recent Developments

On November 23, 2012, we entered into the revolving credit facility (the "Corporate Revolver"). The total size of the Corporate Revolver is $300 million, with $260 million of commitments initially available to us and an additional $40 million of commitments being available if such lenders choose to increase their commitments or if commitments from new financial institutions are added. In connection with the Corporate Revolver, we also amended and restated the $2.0 billion commercial debt facility (the "Facility") to cancel $500 million of unused commitments, cancel the uncommitted $1.0 billion accordion and add certain financial covenants, among other things. As a result of the transaction, $5.3 million of deferred financing costs were written off as a loss on extinguishment of debt.

Ghana

During 2012, we had six liftings of oil totaling 5,905 MBbl from the Jubilee Field production resulting in revenues of $668.0 million. Our average realized price was $113.12 per barrel.

We have received an approval for the Phase 1A PoD of the Jubilee Field, with production from Phase 1A commencing in late 2012. Drilling of the Phase 1A wells is expected to be completed in 2013 and includes eight additional wells, including five production wells and three water injection wells.

In January 2012, the Ntomme-2A appraisal well confirmed a downdip extension of the Ntomme Field on the DT Block. The well encountered high-quality stacked reservoir sandstones. A drill stem test was performed on the well in May 2012, which successfully flowed oil from multiple zones in the reservoir and confirmed continuity with the Ntomme discovery well. Fluid samples recovered from the well indicate an oil gravity of approximately 35 degrees API.

In March 2012, the Enyenra-4A appraisal well confirmed a downdip extension of the Enyenra light oil field on the DT Block. Analysis of well results, including wireline logs, reservoir pressures and fluid samples, indicated the Enyenra-4A well encountered oil-bearing pay. Fluid samples recovered from the well indicate an oil gravity of approximately 34 degrees API. In March 2012, the Owo-1RA (discovery well of the Enyenra field) drill stem test was successful in encountering oil flow across three zones.

Drilling of the Teak-4A appraisal well was completed in May 2012. The well encountered non-commercial reservoirs and accordingly was plugged and abandoned. Total well related costs incurred from inception of $15.0 million are included in exploration expenses in the accompanying consolidated statement of operations for 2012.

In July 2012, the Wawa-1 exploration well made a hydrocarbon discovery on the DT Block. Analysis of well results, including wireline logs, reservoir pressures and fluid samples, indicated the well encountered gas-condensate and oil-bearing pay. Fluid samples recovered from the well indicate an oil gravity of between 38 and 44 degrees API.

In August 2012, a drill stem test performed on the Akasa-1 well on the WCTP Block was successful in encountering oil flow.

In November 2012, we submitted a declaration of commerciality and plan of development covering the Tweneboa, Enyenra and Ntomme discoveries (the "TEN PoD") on the DT Block. The TEN PoD plans for a flexible and expandable development, with an initial base capacity of 80,000 barrels of oil per day. The final development concept is subject to approval from the government of Ghana.

Drilling of the Okure-1 exploration well on the DT Block was completed in December 2012. The well encountered non-commercial reservoirs and accordingly was plugged and abandoned. Total well related costs incurred from inception of $13.8 million are included in exploration expenses in the accompanying consolidated statement of operations for 2012.

The Sapele-1 exploration well on the DT Block was spud in December 2012. Drilling of the well was completed in February 2013. The well is not considered a productive well and accordingly will be plugged and abandoned.

In January 2013, we relinquished the discovery area associated with the Banda discovery on the WCTP Block, as we do not consider this discovery to be commercially viable. As the exploration phase of the WCTP PA has expired, we no longer have any rights to this discovery area (unless we enter into a new petroleum agreement with the Ghana Ministry of Energy and the Ghana National Petroleum Company covering this and other relinquished areas of the WCTP Block). This relinquishment is not expected to impact our consolidated financial statements for the quarter ended March 31, 2013, as we have previously recorded the unsuccessful well costs associated with the Banda-1 exploration well as exploration expenses.

Cameroon

In January 2012, Kosmos entered into a petroleum contract with the Republic of Cameroon for the Fako Block. Kosmos is the operator and has a 100% participating interest in the block. The Republic of Cameroon has an option to acquire an interest of up to 15% in a commercial discovery on 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.

In October 2012, the current renewal period of the Ndian River Block was extended through November 19, 2013 and carries a one-well obligation. The Sipo-1 exploration well on the Ndian River Block spud in February 2013. This well is expected to reach its target depth in April 2013.

Mauritania

In April 2012, we completed negotiations with Mauritania's Ministry of Petroleum, Energy and Mines and executed separate petroleum contracts covering Blocks C8, C12 and C13 offshore Mauritania. Kosmos is the operator and has a 90% participating interest in each of these blocks. The government of Mauritania has a 10% carried interest during the exploration period and the option to participate in any discovery on these blocks, and if it elects to exercise such option its participation interest would be between 10% and 14%. The first phase of the exploration period of the petroleum contract covering each of the blocks is four years in duration. These contracts were officially gazetted by the Government of Mauritania on June 15, 2012, thereby establishing the effective date for the petroleum contracts.

In order to conform the southern boundaries of Blocks C8 and C13 with the Mauritanian border with Senegal, the petroleum contracts were amended in September 2012. The total area covered by the blocks in now 6.6 million acres (26,775 square kilometers). The blocks are located within the western margin of the proven Mauritanian salt basin, on the Atlantic passive margin. The source rock in the basin is the same age and type as the source rock generated by the petroleum system in the Jubilee Field. Additionally, we believe the play model in the basin is similar to the play model found in the Jubilee Field. A petroleum system in Mauritania has been proven by the presence of offshore producing fields in adjacent blocks to those which we hold.

During the first half of 2013, we anticipate initiating a 2D seismic data acquisition program on approximately 6,000 line-kilometers, covering portions of all three blocks. Based on interpretation of results of the 2D seismic data, a 3D seismic program will be targeted for commencement in 2013.

Morocco

In March 2012, we completed a 4,925 square kilometer 3D seismic acquisition program which covered the Essaouira Offshore Block and the Foum Assaka Block, both in the Agadir Basin offshore Morocco. Processing and interpretation of the data continues.

In October 2012, the Moroccan government issued a joint ministerial order approving our acquisition of the additional 18.75% participating interest from Pathfinder, a wholly owned subsidiary of Fastnet, one of our block partners. Upon receipt of this order, we closed the acquisition of such additional participating interest with Pathfinder. We expect final governmental processes required to officially reflect the acquisition under Moroccan law to be completed in due course. After giving effect to the acquisition, our participating interest in the Foum Assaka Offshore Block is 56.25%.

In September 2012, Kosmos entered into an agreement to acquire an additional 37.5% participating interest in the Essaouira Offshore Block from Canamens Energy Morocco SARL, one of our block partners. Certain governmental approvals and processes are still required to be completed before this acquisition can be closed. After completing the acquisition, our participating interest in the Essaouira Offshore Block will be 75%.

In September 2012, Kosmos made its election under the Tarhazoute Reconnaissance Contract to enter into a petroleum contract. Negotiation of the petroleum contract and associated documents is currently ongoing. We anticipate we will be the operator of the license and hold a 75% participating interest.

Suriname

In November 2012, Kosmos closed an agreement with Chevron under which Kosmos assigned half of its interest in Block 42 and Block 45, offshore Suriname, to Chevron. Each party now has a 50% participating interest in Block 42 and Block 45.

In October 2012, we completed a 3D seismic data acquisition program which covered approximately 3,900 square kilometers of portions of Block 42 and Block 45, both in the Suriname-Guyana Basin. Processing of the data is ongoing.

Results of Operations

All of our results, as presented in the table below, represent operations from the Jubilee Field in Ghana. Certain operating results and statistics for the comparative years of 2012, 2011 and 2010 are included in the following table:

	Years Ended December 31,		
	2012	2011	2010
	(In thousands, except per barrel data)		
Sales volumes:			
MBbl	5,905	5,971	—
Revenues:			
Oil sales	$667,951	$666,912	$ —
Average sales price per Bbl	113.12	111.70	—
Costs:			
Oil production, excluding workovers	$ 50,640	$ 83,551	$ —
Oil production, workovers	44,469	—	—
Total oil production costs	$ 95,109	$ 83,551	—
Depletion	$178,568	$135,532	—
Average cost per Bbl:			
Oil production, excluding workovers	$ 8.58	$ 13.99	$ —
Oil production, workovers	7.53	—	—
Total oil production costs	16.11	13.99	—
Depletion	30.24	22.70	—
Oil production cost and depletion costs	$ 46.35	$ 36.69	$ —

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, 2012 vs. 2011

	Years Ended December 31, 2012	Years Ended December 31, 2011	Increase (Decrease)
	(In thousands)		
Revenues and other income:			
Oil and gas revenue	$667,951	$666,912	$ 1,039
Interest income	1,108	9,093	(7,985)
Other income	3,150	775	2,375
Total revenues and other income	672,209	676,780	(4,571)
Costs and expenses:			
Oil and gas production	95,109	83,551	11,558
Exploration expenses	97,712	126,409	(28,697)
General and administrative	160,027	113,579	46,448
Depletion and depreciation	185,707	140,469	45,238
Amortization—deferred financing costs	8,984	16,193	(7,209)
Interest expense	52,207	65,749	(13,542)
Derivatives, net	31,490	11,777	19,713
Loss on extinguishment of debt	5,342	59,643	(54,301)
Doubtful accounts expense	—	(39,782)	39,782
Other expenses, net	1,475	149	1,326
Total costs and expenses	638,053	577,737	60,316
Income before income taxes	34,156	99,043	(64,887)
Income tax expense	101,184	76,686	24,498
Net income (loss)	$(67,028)	$ 22,357	$(89,385)

Oil and gas revenue. Oil and gas revenue increased by $1.0 million during the year ended December 31, 2012 as compared to the year ended December 31, 2011 primarily due to a higher realized price per barrel. We lifted and sold approximately 5,905 MBbl at an average realized price per barrel of $113.12 in 2012 and approximately 5,971 MBbl at an average realized price per barrel of $111.70 in 2011.

Interest income. Interest income decreased by $8.0 million during the year ended December 31, 2012, as compared to the year ended December 31, 2011, primarily due to interest on notes receivable. The related notes receivable was satisfied 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 increased by $2.4 million during the year ended December 31, 2012, as compared to the year ended December 31, 2011, primarily due to an increase in technical services fees and overhead charges billed to partners.

Oil and gas production. Oil and gas production costs increased by $11.6 million during the year ended December 31, 2012 as compared to the year ended December 31, 2011 primarily due to $44.5 million of workover costs related to acid stimulations on Jubilee Field wells, offset by a decrease due to the purchase of the FPSO in December 2011. During the year ended December 31, 2012, the amortization of costs capitalized in connection with the purchase of the FPSO were expensed as depletion. Our average production cost per barrel was $16.11 and $13.99 for the years ended December 31, 2012 and 2011, respectively.

Exploration expenses. Exploration expenses decreased by $28.7 million during the year ended December 31, 2012, as compared to the year ended December 31, 2011. During the year ended December 31, 2012, we incurred $53.9 million for seismic costs for Morocco, Suriname, Ghana and Cameroon; $32.2 million of unsuccessful well costs, primarily related to the Ghana Teak-4A appraisal well and Ghana Okure-1 exploration well; and $9.9 million of new business costs. 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.

General and administrative. General and administrative costs increased by $46.4 million during the year ended December 31, 2012, as compared to the year ended December 31, 2011, primarily due to increases in non-cash expenses of $32.4 million for equity-based compensation and an increase in staffing. Total non-cash general and administrative costs were $83.4 million and $51.0 million for the years ended December 31, 2012 and 2011, respectively.

Depletion and depreciation. Depletion and depreciation increased $45.2 million during the year ended December 31, 2012, as compared with the year ended December 31, 2011, primarily due to an increase in the cost basis of our oil and gas properties related to the purchase of the FPSO and an increase in the number of completed wells.

Amortization—deferred financing costs and Loss on extinguishment of debt. In March 2011, we refinanced our existing commercial debt facilities. As part of the transaction, we incurred approximately $52.3 million of deferred financing costs, in addition to our existing unamortized deferred financing costs of $68.6 million. As a result of the transaction, 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 for the Facility decreased by $7.5 million during the year ended December 31, 2012, as compared to the year ended December 31, 2011, due to the decrease in capitalized deferred financing costs and the longer term associated with the Facility. In November 2012, we amended the Facility and secured a $300 million Corporate Revolver. As a result of these transactions, $5.3 million of deferred financing costs were written off as a loss on extinguishment of debt.

Interest expense. Interest expense decreased by $13.5 million during the year ended December 31, 2012, as compared to the year ended December 31, 2011, primarily due to a decrease in the unrealized loss on the interest rate derivative instruments related to changes in fair value and a lower weighted average interest rate on the Facility, partially offset by an accrual for transaction taxes during the year ended December 31, 2012.

Derivatives, net. Derivatives, net increased $19.7 million during the year ended December 31, 2012, as compared with December 31, 2011, due to the change in fair value and notional amount 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. The Company recognized an income tax provision attributable to earnings of $101.2 million and $76.7 million during 2012 and 2011, respectively. The Company's effective tax rates for 2012 and 2011 were 296.2% and 77.4%, respectively. The large variance in income taxes between 2012 and 2011 is due to the impact of the book/tax difference related to the decrease in fair value of certain vested equity awards. The large effective tax rate in 2012 is due to losses incurred in jurisdictions in which we are not subject to taxes and, therefore, do not generate any income tax benefits; losses in jurisdictions in which we have valuation allowances against our deferred tax assets and therefore we do not realize any tax benefit on such losses; and the impact on deferred tax assets based on the book/tax difference related to the decrease in fair value of certain vested equity awards.

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	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 sales of $666.9 million due to oil production from the Jubilee Field. We lifted and sold approximately 5,971 MBbl 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 satisfied 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 partners 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.

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 refinancing, in addition to our existing unamortized deferred financing costs of $68.6 million. As a result of the debt refinancing, 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 that was provided for in 2010. 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 a valuation allowance related to the Ghana operations 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.

Liquidity and Capital Resources

We are actively engaged in an ongoing process of anticipating and meeting our funding requirements related to exploring for and developing oil and natural gas resources in Africa and South America. We have historically secured funding from issuances of equity and commercial debt facilities to meet our ongoing liquidity requirements. We received our first oil sales in January 2011 from Jubilee

Field production, which generated cash flows from operations during 2012 and 2011. Accordingly, the cash flows generated from our operating activities may also provide an additional source of future funding.

Significant Sources of Capital

Facility

In March 2011, the Company secured a $2.0 billion commercial debt facility (the "Facility") from a number of financial institutions and extinguished the then existing commercial debt facilities. The Facility was syndicated to certain participants of the existing facilities, as well as new participants. The Facility supports our oil and gas exploration, appraisal and development programs and corporate activities.

In February 2012, the Company amended the Facility. The terms and conditions of the Facility remained consistent with the original terms and conditions, however, the International Finance Corporation entered the Facility. The total commitment under the Facility remained unchanged at $2.0 billion.

In November 2012, the Company again amended the Facility. As part of the amendment, we cancelled $500.0 million of unused commitments from the Facility, reducing the total commitments to $1.5 billion. As a result of the transaction, $5.3 million of deferred financing costs were written off as a loss on extinguishment of debt. As of December 31, 2012, borrowings under the Facility totaled $1.0 billion and the undrawn availability under the Facility was $340.4 million.

Interest is the aggregate of the applicable margin (3.25% to 4.75%, depending on the amount of the Facility that is being utilized and the length of time that has passed from the date the Facility was entered into), LIBOR and mandatory cost (if any, as defined in the Facility). Interest is payable on the last day of each interest period (and, if the interest period is longer than six months, on the dates falling at six-month intervals after the first day of the interest period). We pay commitment fees on the undrawn and unavailable portion of the total commitments. Commitment fees are equal to 40% per annum of the then-applicable respective margin when a commitment is available for utilization and, equal to 20% per annum of the then-applicable respective margin when a commitment is not available for utilization. We recognize interest expense in accordance with ASC 835—Interest, which requires interest expense to be recognized using the effective interest method. We determined the effective interest rate based on the estimated level of future borrowings under the Facility.

The Facility provides a revolving-credit and letter of credit facility for an availability period that expires on May 15, 2014 (in the case of the revolving-credit facility) and on the final maturity date (in the case of the letter of credit facility). The available facility amount is subject to borrowing base constraints and is also constrained by an amortization schedule (once repayments under the Facility begin). Beginning on May 15, 2014, outstanding borrowings will be subject to an amortization schedule. The first required payment could be as early as March 31, 2014, subject to the level of outstanding borrowings and the borrowing base constraints. The Facility has a final maturity date of March 29, 2018.

We have the right to cancel all the undrawn commitments under the Facility. The amount of funds available to be borrowed under the Facility, also known as the borrowing base amount, is determined each year on March 31 and September 30 as part of a forecast that is prepared by and agreed to by us and the Technical and Modeling Banks. The formula to calculate the borrowing base amount is based, in part, on the sum of the net present values of net cash flows and relevant capital expenditures reduced by certain percentages.

If an event of default exists under the Facility, the lenders can accelerate the maturity and exercise other rights and remedies, including the enforcement of security granted pursuant to the Facility over certain assets held by us.

We were in compliance with the financial covenants contained in the Facility as of the October 15, 2012 forecast (the most recent assessment date), which requires the maintenance of:

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

In connection with the November 2012 amendment to the Facility, certain terms of the Facility were amended as follows:

- the addition of certain financial covenants such that the Company is required every six months or on a pro forma basis upon giving effect to certain specified transactions to maintain:
  - the debt cover ratio (as defined in the glossary), not more than 3.5x; and
  - the interest cover ratio (as defined in the glossary), not less than 2.25x;
- to allow proceeds from any project permitted to be funded by the Facility to be used, in accordance with certain payment priority provisions, to pay amounts of interest due under, and fees and expenses related to, the $300.0 million Corporate Revolver and certain other debt that may be incurred by the Company;
- the cancellation of the right of the Company to increase the Facility commitments beyond $2.0 billion (i.e. the cancellation of the uncommitted $1.0 billion accordion);
- to permit (i) subsidiaries of the Company (other than certain of the Company's indirect subsidiaries which hold interests in Kosmos Energy Ghana HC) to incur certain indebtedness and guarantees, and grant certain liens over their assets, and (ii) the Ghana Obligors to guarantee the Corporate Revolver and certain other debt that may be incurred by the Company on a subordinated basis, in each case to the extent permitted by the Amended and Restated Facility Agreement and the intercreditor agreement entered into by us and the lenders under the Facility and the Corporate Revolver;
- the exclusion of certain of the Company's subsidiaries doing business in Cameroon and Morocco from (i) the restrictions contained in the charge granted to the lenders under the Facility over the Company's subsidiary, Kosmos Energy Operating, being the intermediate parent of such subsidiaries doing business in Cameroon and Morocco, and (ii) the receipt of funds from draws under the Facility; and
- to make certain other amendments to the terms of the Facility.

Corporate Revolver

In November 2012, we secured a Corporate Revolver from a number of financial institutions. As of December 31, 2012, we had $260.0 million of commitments under the Corporate Revolver. Availability under the Corporate Revolver may be increased up to $300.0 million if existing lenders increase their commitments or if commitments from new financial institutions are added. The Corporate Revolver is available for all subsidiaries for general corporate purposes and for oil and gas exploration, appraisal and development programs and corporate activities.

As of December 31, 2012, there were no borrowings outstanding under the Corporate Revolver and the undrawn availability under the Corporate Revolver was $260.0 million.

Interest is the aggregate of the applicable margin (6.0%), LIBOR and mandatory cost (if any, as defined in the Corporate Revolver). Interest is payable on the last day of each interest period (and, if the interest period is longer than six months, on the dates falling at six-month intervals after the first day of the interest period). We pay commitment fees on the undrawn portion of the total commitments. Commitment fees for the lenders are equal to 40% per annum of the respective margin when a commitment is available for utilization.

The Corporate Revolver has a 3-year availability period that expires on November 20, 2015. The available amount is not subject to borrowing base constraints. We have the right to cancel all the undrawn commitments under the Corporate Revolver. We are required to repay certain amounts due under the Corporate Revolver with sales of certain subsidiaries or sales of certain assets. If an event of default exists under the Corporate Revolver, the lenders can accelerate the maturity and exercise other rights and remedies, including the enforcement of security granted pursuant to the Corporate Revolver over certain assets held by us.

We were in compliance with the financial covenants contained in the Corporate Revolver as of November 23, 2012 (the most recent assessment date), which requires the maintenance of:

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

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

Capital Expenditures and Investments

We expect to incur substantial costs as we continue to develop our oil and natural gas prospects and as we:

- complete our 2013 exploration and appraisal drilling program in our license areas;
- develop our discoveries that we determine to be commercially viable;
- purchase and analyze seismic and other geological and geophysical data to identify future prospects; and
- invest in additional oil and natural gas leases and licenses.

We have relied on a number of assumptions in budgeting for our future activities. These include the number of wells we plan to drill, our participating interests in our prospects, the costs involved in developing or participating in the development of a prospect, the timing of third-party projects, and the availability of suitable equipment and qualified personnel. These assumptions are inherently subject to significant business, political, economic, regulatory, environmental and competitive uncertainties, contingencies and risks, all of which are difficult to predict and many of which are beyond our control. We may need to raise additional funds more quickly if one or more of our assumptions proves to be incorrect or if we choose to expand our hydrocarbon asset acquisition, exploration, appraisal, development efforts or any other activity more rapidly than we presently anticipate. We may decide to raise additional funds before we need them if the conditions for raising capital are favorable. We may seek to sell equity or debt securities or obtain additional bank credit facilities. The sale of equity securities could result in dilution to our shareholders. The incurrence of additional indebtedness could result in increased fixed obligations and additional covenants that could restrict our operations.

2013 Capital Program

We estimate we will incur approximately $525.0 million of capital expenditures for the year ending December 31, 2013. This capital expenditure budget consists of:

- approximately 55% for developmental related expenditures offshore Ghana; and
- approximately 45% for exploration and appraisal related expenditures, including new venture opportunities.

The ultimate amount of capital we will spend may fluctuate materially based on market conditions and the success of our drilling results. Our future financial condition and liquidity will be impacted by, among other factors, our level of production of oil and the prices we receive from the sale of these commodities, the success of our exploration and appraisal drilling program, the number of commercially viable oil and natural gas discoveries made and the quantities of oil and natural gas discovered, the speed with which we can bring such discoveries to production, and the actual cost of exploration, appraisal and development of our oil and natural gas assets.

The following table presents our liquidity and financial position as of December 31, 2012:

	December 31, 2012
	(In thousands)
Cash and cash equivalents	$ 515,164
Drawings under the Facility	1,000,000
Net debt	484,836
Availability under the Facility	$ 340,371
Availability under the Corporate Revolver	260,000
Available borrowings plus cash and cash equivalents	1,115,535

Cash Flows

	Years Ended December 31,		
	2012	2011	2010
		(In thousands)	
Net cash provided by (used in):			
Operating activities	$ 371,530	$ 364,909	$(191,800)
Investing activities	(402,662)	(385,140)	(589,975)
Financing activities	(126,796)	592,908	742,685

Operating activities. Net cash provided by operating activities in 2012 was $371.5 million compared with net cash provided by operating activities of $364.9 million in 2011 and net cash used in operating activities of $191.8 million in 2010 The increase in cash provided by operating activities in 2012 when compared to 2011 was primarily due to positive change in working capital items which offset a decrease in results from operations. The increase in cash provided by operating activities in 2011 when compared to 2010 was primarily due to sales of oil from the Jubilee Field which did not exist in 2010.

Investing activities. Net cash used in investing activities in 2012 was $402.7 million compared with $385.1 million and $590.0 million in 2011 and 2010, respectively. The increase in cash used in investing activities in 2012 when compared to 2011 was primarily attributable to changes in restricted cash, notes receivable and expenditures for oil and gas assets primarily in Ghana for development activities. The decrease in cash used in 2011 when compared to 2010 was primarily attributable to changes in restricted cash, notes receivable and expenditures for oil and gas assets primarily in Ghana for development activities. During 2012, we set aside $23.7 million of restricted cash to support our exploration related activities. During 2011, we released $112.0 million of restricted cash and set aside $26.4 million primarily related to requirements under the Facility.

Financing activities. Net cash used in financing activities in 2012 was $126.8 million compared with net cash provided by financing activities of $592.9 million and $742.7 million in 2011 and 2010, respectively. The decrease in cash provided by financing activities for 2012 when compared to 2011 was primarily due to net proceeds received from the IPO of $580.4 million received in 2011 and an increase in net payments under long-term debt. The decrease in cash provided in 2011 when compared to 2010 was primarily due to a decrease in net borrowings under long-term debt of $695.0 million which offset net proceeds from the IPO of $580.4 million.

Contractual Obligations

The following table summarizes by period the payments due for our estimated contractual obligations as of December 31, 2012:

	Payments Due By Year(3)						
	Total	2013	2014	2015	2016	2017	Thereafter
	(In thousands)						
Operating leases	$ 21,562	$ 2,821	$ 2,921	$ 3,022	$ 3,122	$ 3,223	$ 6,453
Facility(1)	1,000,000	—	191,185	162,668	229,481	333,333	83,333
Interest payments on long-term debt(2)	181,945	46,273	45,936	36,131	34,346	18,080	1,179

(1) The amounts included in the table represent principal maturities only. The scheduled maturities of debt are based on the level of borrowings and the available borrowing base as of December 31, 2012. Any increases or decreases in the level of borrowings or increases or decreases in the available borrowing base would impact the scheduled maturities of debt during the next five years and thereafter. As of December 31, 2012, there were no borrowings under the Corporate Revolver.

(2) Based on outstanding borrowings as noted in (1) above and the LIBOR yield curves at the reporting date and commitment fees related to the Facility and Corporate Revolver.

(3) Does not include purchase commitments for jointly owned fields and facilities where we are not the operator and excludes commitments for exploration activities, including well commitments, in our petroleum contracts.

The following table presents maturities by expected maturity dates under the Facility, the weighted average interest rates expected to be paid on the Facility given current contractual terms and market conditions, and the debt's estimated fair value. Weighted-average interest rates are based on implied forward rates in the yield curve at the reporting date. This table does not take into account amortization of deferred financing costs.

	Years Ending December 31,						Liability Fair Value at December 31, 2012
	2013	2014	2015	2016	2017	Thereafter	
	(In thousands, except percentages)						
Variable rate debt:							
Facility(1)	$ —	$191,185	$162,668	$229,481	$333,333	$83,333	$(1,000,000)
Weighted average interest rate(2)	3.52%	4.09%	4.47%	5.81%	6.44%	6.89%	
Interest rate swaps:							
Notional debt amount(3)(5)	$91,683	$ 47,033	$ 16,875	$ 6,250	$ —	$ —	$ (2,555)
Fixed rate payable	2.22%	2.22%	2.22%	2.22%			
Variable rate receivable(4)	0.49%	0.57%	0.75%	1.11%			
Notional debt amount(3)(5)	$91,683	$ 47,033	$ 16,875	$ 6,250	$ —	$ —	$ (2.713)
Fixed rate payable	2.31%	2.31%	2.31%	2.31%			
Variable rate receivable(4)	0.49%	0.57%	0.75%	1.11%			
Notional debt amount(3)(5)	$19,057	$ 1,868	$ —	$ —	$ —	$ —	$ (98)
Fixed rate payable	0.98%	0.98%					
Variable rate receivable(4)	0.49%	0.55%					
Notional debt amount(3)(5)	$24,680	$ 38,434	$ 23,137	$ —	$ —	$ —	$ (573)
Fixed rate payable	1.34%	1.34%	1.34%				
Variable rate receivable(4)	0.49%	0.57%	0.68%				

(1) The amounts included in the table represent principal maturities only. The scheduled maturities of debt are based on the level of borrowings and the available borrowing base as of December 31, 2012. Any increases or decreases in the level of borrowings or increases or decreases in the available borrowing base would impact the scheduled maturities of debt during the next five years and thereafter. As of December 31, 2012, there were no borrowings under the Corporate Revolver.

(2) Based on outstanding borrowings as noted in (1) above and the LIBOR yield curves at the reporting date. Excludes commitment fees related to the Facility and Corporate Revolver.

(3) Represents weighted average notional contract amounts of interest rate derivatives.

(4) Based on implied forward rates in the yield curve at the reporting date.

(5) In the final year of maturity, represents notional amount from January - June.

Off-Balance Sheet Arrangements

As of December 31, 2012, we did not have any off-balance sheet arrangements.

Critical Accounting Policies

This discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements, which have been prepared in accordance with generally accepted accounting principles in the United States. The preparation of our financial statements requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities as of the date the financial statements are available to be issued. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates. Our significant accounting policies are detailed in "Item 8. Financial Statements and Supplementary Data—Note 2—Accounting Policies." We have outlined below certain accounting policies that are of particular importance to the presentation of our financial position and results of operations and require the application of significant judgment or estimates by our management.

Revenue Recognition. We use the sales method of accounting for oil and gas revenues. Under this method, we recognize revenues on the volumes sold based on the provisional sales prices. The volumes sold may be more or less than the volumes to which we are entitled based on our ownership interest in the property. These differences result in a condition known in the industry as a production imbalance. A receivable or liability is recognized only to the extent that we have an imbalance on a specific property greater than the expected remaining proved reserves on such property. As of December 31, 2012 and 2011, we had no oil and gas imbalances recorded in our consolidated financial statements.

Our oil and gas revenues are based on provisional price contracts which contain an embedded derivative that is required to be separated from the host contract for accounting purposes. The host contract is the receivable from oil sales at the spot price on the date of sale. The embedded derivative, which is not designated as a hedge for accounting purposes, is marked to market through oil and gas revenue each period until the final settlement occurs, which generally is limited to the month after the sale occurs.

Exploration and Development Costs. We follow the successful efforts method of accounting for our oil and gas properties. Acquisition costs for proved and unproved properties are capitalized when incurred. Costs of unproved properties are transferred to proved properties when a determination that proved reserves have been found. Exploration costs, including geological and geophysical costs and costs of carrying unproved properties, are charged to expense as incurred. Exploratory drilling costs are capitalized when incurred. If exploratory wells are determined to be commercially unsuccessful or dry holes, the applicable costs are expensed. Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized. Costs incurred to operate and maintain wells and equipment and to lift crude oil and natural gas to the surface are expensed.

Receivables. Our receivables consist of joint interest billings, oil sales, notes and other receivables for which we generally do not require collateral security. Receivables from joint interest owners are stated at amounts due, net of any allowances for doubtful accounts. We determine our allowance by considering the length of time past due, future net revenues of the debtor's ownership interest in oil and natural gas properties we operate, and the owner's ability to pay its obligation, among other things.

Income Taxes. We account for income taxes as required by the ASC 740—Income Taxes ("ASC 740"). We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments occur in the calculation of certain tax assets and liabilities that arise from differences in the timing and recognition of revenue and expense for tax and financial reporting purposes. Our federal, state and international tax returns are generally not prepared or filed before the consolidated financial statements are prepared; therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits, and net operating loss carryforwards. Adjustments related to these estimates are recorded in our tax provision in the period in which we file our income tax returns. Further, we must assess the likelihood that we will be able to realize or utilize our deferred tax assets. If realization is not more likely than not, we must record a valuation allowance against such deferred tax assets for the amount we would not expect to recover, which would result in no benefit for the deferred tax amounts. As of December 31, 2012 and 2011, we have a valuation allowance to reduce certain deferred tax assets to amounts that are more likely than not to be realized. If our estimates and judgments regarding our ability to realize our deferred tax assets change, the benefits associated with those deferred tax assets may increase or decrease in the period our estimates and judgments change. On a quarterly basis, management evaluates the need for and adequacy of valuation allowances based on the expected realizability of the deferred tax asses and adjusts the amount of such allowances, if necessary.

ASC 740 provides a more-likely-than-not standard in evaluating whether a valuation allowance is necessary after weighing all of the available evidence. When evaluating the need for a valuation allowance, we consider all available positive and negative evidence, including the following:

- the status of our operations in the particular taxing jurisdiction including whether we have commenced production from a commercial discovery;
- whether a commercial discovery has resulted in significant proved reserves that have been independently verified;
- the amounts and history of taxable income or losses in a particular jurisdiction;
- projections of future taxable income, including the sensitivity of such projections to changes in production volumes and prices;
- the existence, or lack thereof, of statutory limitations on the period that net operating losses may be carried forward in a jurisdication; and
- the creation and timing of future taxable income associated with the turn around of deferred tax liabilities in excess of deferred tax assets.

Derivative Instruments and Hedging Activities. We utilize oil derivative contracts to mitigate our exposure to commodity price risk associated with our anticipated future oil production. These derivative contracts consist of three-way collars. We also use interest rate swap contracts to mitigate our exposure to interest rate fluctuations related to our long-term debt. Our derivative financial instruments are recorded on the balance sheet as either assets or a liabilities measured at fair value. We do not apply hedge accounting to our oil derivative contracts. Effective June 1, 2010, we discontinued hedge accounting on our interest rate swap contracts and accordingly the changes in the fair value of the instruments are recognized in earnings in the period of change. The effective portions of the discontinued hedges as of May 31, 2010, are included in accumulated other comprehensive income or loss ("AOCI") in the equity section of the accompanying consolidated balance sheets, and are being transferred to earnings when the hedged transaction settles.

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

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

Asset Retirement Obligations. We account for asset retirement obligations as required by the ASC 410—Asset Retirement and Environmental Obligations. Under these standards, the fair value of a liability for an asset retirement obligation is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. If a reasonable estimate of fair value cannot be made in the period the asset retirement obligation is incurred, the liability is recognized when a reasonable estimate of fair value can be made. If a tangible long-lived asset with an existing asset retirement obligation is acquired, a liability for that obligation shall be recognized at the asset's acquisition date as if that obligation were incurred on that date. In addition, a liability for the fair value of a conditional asset retirement obligation is recorded if the fair value of the liability can be reasonably estimated. We capitalize the asset retirement costs by increasing the carrying amount of the related long-lived asset by the same amount as the liability. We record increases in the discounted abandonment liability resulting from the passage of time in depletion and depreciation in the consolidated statement of operations. Estimating the future restoration and removal costs requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Additionally, asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligations, a corresponding adjustment is made to the oil and gas property balance.

Impairment of Long-Lived Assets. We review our long-lived assets for impairment when changes in circumstances indicate that the carrying amount of an asset may not be recoverable. ASC 360—Property, Plant and Equipment requires an impairment loss to be recognized if the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. The carrying amount of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. That assessment shall be based on the carrying amount of the asset at the date it is tested for recoverability, whether in use or under development. An impairment loss shall be measured as the amount by which the carrying amount of a long-lived asset exceeds its fair value. Assets to be disposed of and assets not expected to provide any future service potential to us are recorded at the lower of carrying amount or fair value less cost to sell.

New Accounting Pronouncements

In December 2011, the FASB issued ASU No. 2011-11, "Disclosures about Offsetting Assets and Liabilities," to improve reporting and transparency of offsetting (netting) assets and liabilities and the related affects on the financial statements. This ASU is effective for fiscal years and interim periods within those years beginning on or after January 1, 2013. We do not expect the adoption of this ASU will have a material effect on our consolidated financial statements.

Item 7A. Qualitative and Quantitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risks" as it relates to our currently anticipated transactions refers to the risk of loss arising from changes in commodity prices and interest rates. These disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage ongoing market risk exposures. We enter into market-risk sensitive instruments for purposes other than to speculate.

We manage market and counterparty credit risk in accordance with policies and guidelines. In accordance with these policies and guidelines, our management determines the appropriate timing and extent of derivative transactions. See "Item 8. Financial Statements and Supplementary Data—Note 2—Accounting Policies, Note 10—Derivative Financial Information and Note 11—Fair Value

Measurements" for a description of the accounting procedures we follow relative to our derivative financial instruments.

The following table reconciles the changes that occurred in fair values of our open derivative contracts during the year ended December 31, 2012:

	Derivative Contracts Assets (Liabilities)		
	Commodities	Interest Rates	Total
		(In thousands)	
Fair value of contracts outstanding as of December 31, 2011	$(24,760)	$(8,074)	$(32,834)
Changes in contract fair value	(15,838)	(2,464)	(18,302)
Contract maturities (settlements)	23,995	4,599	28,594
Fair value of contracts outstanding as of December 31, 2012	$(16,603)	$(5,939)	$(22,542)

Commodity Derivative Instruments

We enter into various oil derivative contracts to mitigate our exposure to commodity price risk associated with anticipated future oil production. These contracts currently consist of three-way collars.

Commodity Price Sensitivity

The following table provides information about our oil derivative financial instruments that were sensitive to changes in oil prices as of December 31, 2012:

			Weighted Average Price per Bbl				Liability Fair Value at
Term(3)	Type of Contract	MBbl	Deferred Premium	Floor	Ceiling	Calls	December 31, 2012(1)(2)
2013:							
January—December	Three-way collars	1,500	$4.82	$95.00	$105.00	$125.00	$12,187
January—December	Three-way collars	1,004	—	87.50	115.00	135.00	923
January—December	Three-way collars	1,000	—	90.00	115.39	135.00	423
January—December	Three-way collars	1,000	—	90.08	115.00	135.00	530
2014:							
January—December	Three-way collars	1,500	1.22	85.00	115.00	140.00	267

(1) Fair values are based on the average forward Dated Brent oil prices on December 31, 2012 which by year are: 2013—$107.28 and 2014—$102.20. These fair values are subject to changes in the underlying commodity price. The average forward Dated Brent oil prices based on February 18, 2013 market quotes by year are: 2013—$113.98 and 2014—$107.13.

(2) Excludes $3.4 million of cash settlements made on our purchased puts and swaps with calls which were settled in the month subsequent to period end.

(3) In January 2013, we entered into costless three-way collar contracts for 1.0 MMBbl from January 2014 through December 2014 with a floor price of $85.00 per Bbl, a weighted average ceiling price of $115.01 per Bbl and a call price of $140.00 per Bbl. The three-way collar contracts are indexed to Dated Brent prices.

Interest Rate Derivative Instruments

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

Interest Rate Sensitivity

At December 31, 2012, we had indebtedness outstanding under the Facility of $1.0 billion, of which $746.4 million bore interest at floating rates. The interest rate on this indebtedness as of December 31, 2012 was approximately 3.5%. If LIBOR increased 10% at this level of floating rate debt, we would pay an additional $0.2 million in interest expense per year on the Facility. We pay commitment fees on the $340.4 million of undrawn availability and $159.6 million of unavailable commitments under the Facility and on the $260.0 million of undrawn availability under the Corporate Revolver, which are not subject to changes in interest rates.

As of December 31, 2012, the fair market value of our interest rate swaps was a net liability of approximately $5.9 million. If LIBOR increased by 10%, we estimate the liability would decrease to approximately $5.7 million, and if LIBOR decreased by 10%, we estimate the liability would increase to approximately $6.2 million.

Item 8. Financial Statements and Supplementary Data

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Kosmos Energy Ltd.

We have audited the accompanying consolidated balance sheets of Kosmos Energy Ltd. as of December 31, 2012 and 2011, and the related consolidated statements of operations, comprehensive income (loss), shareholders' equity/unit holdings equity and cash flows for each of the three years in the period ended December 31, 2012. Our audits also included the financial statement schedules included at Item 15(a). These financial statements and schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedules based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Kosmos Energy Ltd. at December 31, 2012 and 2011, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly, in all material respects, the financial information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Kosmos Energy Ltd.'s internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Dallas, Texas
February 25, 2013

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Kosmos Energy Ltd.

We have audited Kosmos Energy Ltd.'s internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Kosmos Energy Ltd.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting appearing in Item 9A. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, Kosmos Energy Ltd. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Kosmos Energy Ltd. as of December 31, 2012 and 2011, and the related consolidated statements of operations, comprehensive income (loss), shareholders' equity/unit holdings equity and cash flows for each of the three years in the period ended December 31, 2012 of Kosmos Energy Ltd. and our report dated February 25, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Dallas, Texas
February 25, 2013

KOSMOS ENERGY LTD.

CONSOLIDATED BALANCE SHEETS

(In thousands, except share data)

	December 31, 2012	December 31, 2011
Assets		
Current assets:		
Cash and cash equivalents	$ 515,164	$ 673,092
Restricted cash	21,341	23,747
Receivables:		
Joint interest billings	21,539	199,699
Oil sales	108,995	109,475
Other	3,682	981
Inventories	33,281	27,101
Prepaid expenses and other	10,470	13,913
Current deferred tax assets	34,585	64,473
Derivatives	1,061	—
Total current assets	750,118	1,112,481
Property and equipment:		
Oil and gas properties	1,510,312	1,367,265
Other property	15,450	9,776
Property and equipment, net	1,525,762	1,377,041
Other assets:		
Restricted cash	29,884	3,800
Deferred financing costs, net of accumulated amortization of $13,922 and $6,582, respectively	50,214	54,847
Long-term deferred tax assets	10,145	3,765
Total assets	$2,366,123	$2,551,934
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable	$ 128,855	$ 278,006
Accrued liabilities	41,021	37,194
Derivatives	20,377	24,407
Total current liabilities	190,253	339,607
Long-term liabilities:		
Long-term debt	1,000,000	1,110,000
Derivatives	3,226	8,427
Asset retirement obligations	27,484	20,670
Deferred tax liability	104,137	47,608
Other long-term liabilities	12,117	4,896
Total long-term liabilities	1,146,964	1,191,601
Shareholders' equity:		
Preference shares, $0.01 par value; 200,000,000 authorized shares; zero issued at December 31, 2012 and 2011	—	—
Common shares, $0.01 par value; 2,000,000,000 authorized shares; 391,423,703 and 390,530,946 issued at December 31, 2012 and 2011, respectively	3,914	3,905
Additional paid-in capital	1,712,880	1,629,453
Accumulated deficit	(683,176)	(616,148)
Accumulated other comprehensive income	3,685	3,522
Treasury stock, at cost, 2,731,941 and 649,818 shares at December 31, 2012 and 2011, respectively	(8,397)	(6)
Total shareholders' equity	1,028,906	1,020,726
Total liabilities and shareholders' equity	$2,366,123	$2,551,934

See accompanying notes.

KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)

	December 31, 2012	2011	2010
Revenues and other income:			
Oil and gas revenue	$667,951	$666,912	$ —
Interest income	1,108	9,093	4,231
Other income	3,150	775	5,109
Total revenues and other income	672,209	676,780	9,340
Costs and expenses:			
Oil and gas production	95,109	83,551	—
Exploration expenses	97,712	126,409	73,126
General and administrative	160,027	113,579	98,967
Depletion and depreciation	185,707	140,469	2,423
Amortization—deferred financing costs	8,984	16,193	28,827
Interest expense	52,207	65,749	59,582
Derivatives, net	31,490	11,777	28,319
Loss on extinguishment of debt	5,342	59,643	—
Doubtful accounts expense	—	(39,782)	39,782
Other expenses, net	1,475	149	1,094
Total costs and expenses	638,053	577,737	332,120
Income (loss) before income taxes	34,156	99,043	(322,780)
Income tax expense (benefit)	101,184	76,686	(77,108)
Net income (loss)	(67,028)	22,357	(245,672)
Accretion to redemption value of convertible preferred units	—	(24,442)	(77,313)
Net loss attributable to common shareholders/unit holders	$(67,028)	$ (2,085)	$(322,985)
Net income (loss) per share attributable to common shareholders (the year ended December 31, 2011 represents the period from May 16, 2011 to December 31, 2011) (Note 16):			
Basic	$ (0.18)	$ 0.09	
Diluted	$ (0.18)	$ 0.09	
Weighted average number of shares used to compute net income (loss) per share (the year ended December 31, 2011 represents the period from May 16, 2011 to December 31, 2011) (Note 16):			
Basic	371,847	368,474	
Diluted	371,847	368,607	

See accompanying notes.

KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(In thousands)

	Years Ended December 31,		
	2012	2011	2010
Net income (loss)	$(67,028)	$22,357	$(245,672)
Other comprehensive income :			
Change in fair value of cash flow hedges	—	—	(4,838)
Reclassification adjustments for derivative losses included in net income (loss)	163	2,934	5,426
Income tax benefit	1,027	(1,027)	—
Other comprehensive income	1,190	1,907	588
Comprehensive income (loss)	$(65,838)	$24,264	$(245,084)

See accompanying notes.

KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY/UNIT HOLDINGS EQUITY

(In thousands)

	Common Units		Common Shares		Additional Paid-in Capital	Accumulated Deficit	Accumulated Other Comprehensive Income	Treasury Stock	Total
	Units	Amount	Shares	Amount					
Balance as of December 31, 2009	18,667	$ 516	—	$ —	$ 19,108	$(237,480)	$ —	$ —	$ (217,856)
Issuance of profit units	411	—	—	—	—	—	—	—	—
Relinquishments of profit units	(8)	—	—	—	—	—	—	—	—
Equity-based compensation	—	—	—	—	13,791	—	—		13,791
Derivatives, net	—	—	—	—		—	588	—	588
Accrete convertible preferred units to redemption amount	—	—	—	—	(21,143)	(132,363)	—	—	(153,506)
Accrete value of Series C Convertible Preferred Units	—	—	—	—	(11,756)	—	—	—	(11,756)
Net loss	—	—	—	—	—	(245,672)	—	—	(245,672)
Balance as of December 31, 2010	19,070	516	—	—	—	(615,515)	588	—	(614,411)
Issuance of profit units	1,783	—	—	—	—	—	—	—	—
Relinquishments of profit units	(2,686)	—	—	—	—	—	—	—	—
Accrete convertible preferred units to redemption amount	—	—	—	—	(1,452)	(22,990)	—	—	(24,442)
Common and restricted shares issued upon corporate reorganization	(18,167)	(516)	341,177	3,412	1,000,052	—	—	—	1,002,948
Common shares issued at initial public offering, net of offering costs	—	—	34,518	345	580,029	—	—	—	580,374
Equity-based compensation	—	—	—	—	50,966	—	—	—	50,966
Derivatives, net	—	—	—	—	—	—	2,934	—	2,934
Restricted stock awards	—	—	14,836	148	(148)	—	—	—	—
Restricted stock forfeitures	—	—	—	—	6	—	—	(6)	—
Net income	—	—	—	—	—	22,357	—	—	22,357
Balance as of December 31, 2011	—	—	390,531	3,905	1,629,453	(616,148)	3,522	(6)	1,020,726
Equity-based compensation	—	—	—	—	83,423	—	—	—	83,423
Derivatives, net	—	—	—	—	—	—	163	—	163
Restricted stock awards	—	—	893	9	(9)	—	—	—	—
Restricted stock forfeitures	—	—	—	—	13	—	—	(13)	—
Purchase of treasury stock	—	—	—	—	—	—	—	(8,378)	(8,378)
Net loss	—	—	—	—	—	(67,028)	—	—	(67,028)
Balance as of December 31, 2012	—	$ —	391,424	$3,914	$1,712,880	$(683,176)	$ 3,685	$(8,397)	$1,028,906

See accompanying notes.

KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31,		
	2012	2011	2010
Operating activities			
Net income (loss)	$ (67,028)	$ 22,357	$(245,672)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depletion, depreciation and amortization	194,691	156,662	31,250
Deferred income taxes	80,036	56,457	(77,614)
Unsuccessful well costs	32,229	91,254	59,401
Non-cash change in fair value of derivatives	18,465	21,014	34,545
Cash settlements on derivatives	(28,594)	(19,203)	—
Equity-based compensation	83,423	50,966	13,791
Doubtful accounts expense	—	(39,782)	39,782
Loss on extinguishment of debt	5,342	59,643	—
Other	7,890	2,953	721
Changes in assets and liabilities:			
(Increase) decrease in receivables	176,905	(122,859)	(100,605)
(Increase) decrease in inventories	(7,385)	4,176	(12,699)
(Increase) decrease in prepaid expenses and other	3,443	(635)	(12,429)
Increase (decrease) in accounts payable	(126,401)	89,214	65,800
Increase (decrease) in accrued liabilities	(1,486)	(7,308)	11,929
Net cash provided by (used in) operating activities	371,530	364,909	(191,800)
Investing activities			
Oil and gas assets	(368,990)	(478,943)	(444,712)
Other property	(9,994)	(4,303)	(1,452)
Notes receivable	—	13,653	(61,811)
Restricted cash	(23,678)	84,453	(82,000)
Net cash used in investing activities	(402,662)	(385,140)	(589,975)
Financing activities			
Borrowings under long-term debt	—	1,503,000	760,000
Payments on long-term debt	(110,000)	(1,438,000)	—
Net proceeds from the initial public offering	—	580,374	—
Purchase of treasury stock	(8,378)	—	—
Deferred financing costs	(8,418)	(52,466)	(17,315)
Net cash provided by (used in) financing activities	(126,796)	592,908	742,685
Net increase (decrease) in cash and cash equivalents	(157,928)	572,677	(39,090)
Cash and cash equivalents at beginning of period	673,092	100,415	139,505
Cash and cash equivalents at end of period	$ 515,164	$ 673,092	$ 100,415
Supplemental cash flow information			
Cash paid for:			
Interest	$ 41,234	$ 56,845	$ 52,472
Income taxes	$ 22,020	$ 15,550	$ 762
Non-cash activities:			
Notes receivable applied to FPSO purchase	$ —	$ (102,783)	$ —
Deemed payment and termination of notes receivable	$ —	$ —	$ 90,197

See accompanying notes.

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements

1. Organization

Kosmos Energy Ltd. was incorporated pursuant to the laws of Bermuda in January 2011 to become a holding company for Kosmos Energy Holdings. Kosmos Energy Holdings is a privately held Cayman Islands company that was formed in March 2004. As a holding company, Kosmos Energy Ltd.'s management operations are conducted through a wholly owned subsidiary, Kosmos Energy, LLC. The terms "Kosmos," the "Company," "we," "us," "our," "ours," and similar terms when used in the present tense or prospectively or for historical periods since May 16, 2011 refer to Kosmos Energy Ltd. and its wholly owned subsidiaries and for historical periods prior to May 16, 2011 refer to Kosmos Energy Holdings and its wholly owned subsidiaries, unless the context indicates otherwise.

We are a leading independent oil and gas exploration and production company focused on frontier and emerging areas in Africa and South America. Our asset portfolio includes existing production and other major project developments offshore Ghana, as well as exploration licenses with significant hydrocarbon potential offshore Mauritania, Morocco and Suriname and onshore Cameroon.

In May 2011, contemporaneous with Kosmos Energy Ltd.'s initial public offering ("IPO"), the Series A Convertible Preferred Units, Series B Convertible Preferred Units and Series C Convertible Preferred Units (collectively the "Convertible Preferred Units") and common units of Kosmos Energy Holdings were exchanged into common shares of Kosmos Energy Ltd. based on the pre-offering equity value of such interests in our corporate reorganization (the "corporate reorganization"). This resulted in the Convertible Preferred Units and the common units being exchanged into 277.7 million and 63.5 million common shares of Kosmos Energy Ltd., respectively, or 341.2 million common shares in the aggregate. The 341.2 million common shares included 10.0 million service vesting restricted stock awards issued to management and employees in exchange for unvested profit units in connection with our corporate reorganization. The common shares have one vote per share and a par value of $0.01. As a result of this corporate reorganization, Kosmos Energy Holdings became wholly owned by Kosmos Energy Ltd. Subsequent to this exchange, we have one class of common stock with issued and outstanding shares.

Kosmos Energy Ltd. completed its IPO of 33.0 million common shares on May 16, 2011. In June 2011, the Company closed the sale of an additional 1.5 million common shares pursuant to the over-allotment option exercised by the underwriters of the IPO. This partial exercise of the over-allotment option brings the total number of common shares sold in the offering to 34.5 million. Our net proceeds from the sale of 34.5 million common shares, after underwriting discounts and commissions and offering expenses, were $580.4 million.

We have one reportable segment, which is the exploration and production of oil and natural gas. Substantially all of our long-lived assets and product sales are related to production located offshore Ghana.

2. Accounting Policies

Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Kosmos Energy Ltd. and its wholly owned subsidiaries. All intercompany transactions have been eliminated.

2. Accounting Policies (Continued)

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosures of contingent assets and liabilities. Actual results could differ from these estimates.

Reclassifications

Certain prior period amounts have been reclassified to conform with the current year presentation. Such reclassifications had no impact on our reported net income, current assets, total assets, current liabilities, total liabilities or shareholders equity.

Cash and Cash Equivalents

Cash and cash equivalents includes demand deposits and funds invested in highly liquid instruments with original maturities of three months or less at the date of purchase.

Restricted Cash

In accordance with our commercial debt facility, we are required to maintain a restricted cash balance that is sufficient to meet the payment of interest and fees for the next six-month period. As of December 31, 2012 and 2011, we had $21.3 million and $23.7 million, respectively, in current restricted cash to meet this requirement. Additionally, as of December 31, 2012 and 2011, we had $29.9 million and $3.8 million, respectively, of long-term restricted cash used to cash collateralize performance guarantees related to our petroleum agreements.

Receivables

Our receivables consist of joint interest billings, oil sales and other receivables for which the Company generally does not require collateral security. Receivables from joint interest owners are stated at amounts due, net of any allowances for doubtful accounts. We determine our allowance by considering the length of time past due, future net revenues of the debtor's ownership interest in oil and natural gas properties we operate, and the owner's ability to pay its obligation, among other things. We did not have any allowances for doubtful accounts as of December 31, 2012 and 2011.

Inventories

Inventories consisted of $33.1 million and $26.9 million of materials and supplies and $0.2 million and $0.2 million of hydrocarbons as of December 31, 2012 and 2011, respectively. The Company's materials and supplies inventory primarily consists of casing and wellheads and is stated at the lower of cost, using the weighted average cost method, or market.

Hydrocarbon inventory is carried at the lower of cost, using the weighted average cost method, or market. Hydrocarbon inventory costs include expenditures and other charges (including depletion) directly and indirectly incurred in bringing the inventory to its existing condition. Selling expenses and general and administrative expenses are reported as period costs and excluded from inventory costs.

2. Accounting Policies (Continued)

Exploration and Development Costs

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

The Company evaluates unproved property, other than well related costs, periodically for impairment. These costs are generally related to the acquisition of leasehold costs. The impairment assessment considers results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects. If the quantity of potential future reserves determined by such evaluations is not sufficient to fully recover the cost invested in each project, the Company will recognize an impairment loss at that time.

Depletion, Depreciation and Amortization

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

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

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

Amortization of deferred financing costs is computed using the straight-line method over the life of the related debt.

Capitalized Interest

Interest costs from external borrowings are capitalized on major projects with an expected construction period of one year or longer. Capitalized interest is added to the cost of the underlying asset and is depleted on the unit-of-production method in the same manner as the underlying assets.

2. Accounting Policies (Continued)

Asset Retirement Obligations

The Company accounts for asset retirement obligations as required by ASC 410—Asset Retirement and Environmental Obligations. Under these standards, the fair value of a liability for an asset retirement obligation is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. If a reasonable estimate of fair value cannot be made in the period the asset retirement obligation is incurred, the liability is recognized when a reasonable estimate of fair value can be made. If a tangible long-lived asset with an existing asset retirement obligation is acquired, a liability for that obligation is recognized at the asset's acquisition date. In addition, a liability for the fair value of a conditional asset retirement obligation is recorded if the fair value of the liability can be reasonably estimated. We capitalize the asset retirement costs by increasing the carrying amount of the related long-lived asset by the same amount as the liability. We record increases in the discounted abandonment liability resulting from the passage of time in depletion and depreciation in the consolidated statement of operations.

Variable Interest Entity

A variable interest entity ("VIE"), as defined by ASC 810—Consolidation, is an entity that by design has insufficient equity to permit it to finance its activities without additional subordinated financial support or equity holders that lack the characteristics of a controlling financial interest. VIEs are consolidated by the primary beneficiary, which is the entity that has the power to direct the activities of the VIE that most significantly impact the VIE's performance and will absorb losses or receive benefits from the VIE that could potentially be significant to the VIE.

Our wholly owned subsidiary, Kosmos Energy Finance International, meets the definition of a VIE. The Company is the primary beneficiary of this VIE, which is consolidated in these financial statements.

Prior to the incorporation of Kosmos Energy Finance International on March 18, 2011, Kosmos Energy Finance International did not have any financial statement activity. Kosmos Energy Finance International's following assets and liabilities are shown on the face of the consolidated balance sheet as of December 31, 2012 and 2011: current restricted cash; deferred financing costs; long-term debt; and long-term derivatives liabilities. At December 31, 2012, Kosmos Energy Finance International had $118.8 million in cash and cash equivalents, $0.2 million in prepaid expenses and other, $0.5 million in accrued liabilities and $6.6 million in other long-term liabilities. At December 31, 2011, Kosmos Energy Finance International had $231.6 million in cash and cash equivalents, $0.1 million in other receivables, $1.2 million in accrued liabilities and $3.0 million in other long-term liabilities.

Impairment of Long-lived Assets

The Company reviews its long-lived assets for impairment when changes in circumstances indicate that the carrying amount of an asset may not be recoverable. ASC 360—Property, Plant and Equipment requires an impairment loss to be recognized if the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. The carrying amount of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. That assessment shall be based on the carrying amount of the asset at the date it is tested for recoverability, whether in use or under development. An impairment loss shall be measured as the amount by which the carrying amount of a long-lived asset exceeds its fair value.

2. Accounting Policies (Continued)

Assets to be disposed of and assets not expected to provide any future service potential to the Company are recorded at the lower of carrying amount or fair value less cost to sell.

Derivative Instruments and Hedging Activities

We utilize oil derivative contracts to mitigate our exposure to commodity price risk associated with our anticipated future oil production. These derivative contracts consist of three-way collars. We also use interest rate swap contracts to mitigate our exposure to interest rate fluctuations related to our long-term debt. Our derivative financial instruments are recorded on the balance sheet as either assets or liabilities and are measured at fair value. We do not apply hedge accounting to our oil derivative contracts. Effective June 1, 2010, we discontinued hedge accounting on our interest rate swap contracts. Therefore, from that date forward, the changes in the fair value of the instruments are recognized in earnings during the period of change. The effective portions of the discontinued hedges as of May 31, 2010, are included in accumulated other comprehensive income or loss ("AOCI") in the equity section of the accompanying consolidated balance sheets, and are being transferred to earnings when the hedged transaction settles. See Note 10—Derivative Financial Instruments.

Estimates of Proved Oil and Natural Gas Reserves

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

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

Revenue Recognition

We use the sales method of accounting for oil and gas revenues. Under this method, we recognize revenues on the volumes sold based on the provisional sales prices. The volumes sold may be more or less than the volumes to which we are entitled based on our ownership interest in the property. These differences result in a condition known in the industry as a production imbalance. A receivable or liability is recognized only to the extent that we have an imbalance on a specific property greater than the expected remaining proved reserves on such property. As of December 31, 2012 and 2011, we had no oil and gas imbalances recorded in our consolidated financial statements.

Our oil and gas revenues are based on provisional price contracts which contain an embedded derivative that is required to be separated from the host contract for accounting purposes. The host

2. Accounting Policies (Continued)

contract is the receivable from oil sales at the spot price on the date of sale. The embedded derivative, which is not designated as a hedge, is marked to market through oil and gas revenue each period until the final settlement occurs, which generally is limited to the month after the sale occurs.

Equity-based Compensation

For equity-based compensation awards, compensation expense is recognized in the Company's financial statements over the awards' vesting periods based on their grant date fair value. The Company utilizes (i) the closing stock price on the date of grant to determine the fair value of service vesting restricted stock awards and restricted stock units and (ii) a Monte Carlo simulation to determine the fair value of restricted stock awards and restricted stock units with a combination of market and service vesting criteria.

Treasury Stock

We record treasury stock purchases at cost. All of our treasury stock purchases are from our employees that surrendered shares to the Company to satisfy their minimum tax withholding requirements and were not part of a formal stock repurchase plan. Additionally, treasury stock includes forfeited restricted stock awards granted under our long-term incentive plan.

Income Taxes

The Company accounts for income taxes as required by ASC 740—Income Taxes. Under this method, deferred income taxes are determined based on the difference between the financial statement and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse. Valuation allowances are established when necessary to reduce deferred tax assets to the amounts expected to be realized. On a quarterly basis, management evaluates the need for and adequacy of valuation allowances based on the expected realizability of the deferred tax assets and adjusts the amount of such allowances, if necessary.

We recognize tax benefits from uncertain tax positions only if it is more likely than not that the tax position will be sustained upon examination by the tax authorities, based on the technical merits of the position. Accordingly, we measure tax benefits from such positions based on the most likely outcome to be realized.

Foreign Currency Translation

The U.S. dollar is the functional currency for the Company's foreign operations. Foreign currency transaction gains and losses and adjustments resulting from translating monetary assets and liabilities denominated in foreign currencies are included in other expenses. Cash balances held in foreign currencies are not significant, and as such, the effect of exchange rate changes is not material to any reporting period.

Concentration of Credit Risk

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

2. Accounting Policies (Continued)

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. We have required our marketing agent to post a letter of credit covering the estimated proceeds from our revenue transactions, until such proceeds are received.

Recent Accounting Standards

In December 2011, the FASB issued ASU No. 2011-11, "Disclosures about Offsetting Assets and Liabilities," to improve reporting and transparency of offsetting (netting) assets and liabilities and the related effects on the financial statements. This ASU is effective for fiscal years and interim periods within those years beginning on or after January 1, 2013. We do not expect the adoption of this ASU will have a material effect on our consolidated financial statements.

3. Acquisition of FPSO

Effective May 7, 2010, Tullow Ghana Limited, a subsidiary of Tullow Oil plc, ("Tullow") as Unit Operator for and on behalf of the Jubilee Unit partners under the Unitization and Unit Operating Agreement ("Jubilee UUOA"), entered into the Advance Payments Agreement with MODEC, Inc. ("MODEC") related to partial funding of the construction of the FPSO. The maturity date of the Advance Payments Agreement was extended from September 15, 2011 through the acquisition date of the FPSO.

On December 29, 2011, the Jubilee Unit partners acquired the FPSO we are using to produce hydrocarbons from the Jubilee Field from MODEC at a cost of $202.6 million net to Kosmos. At the time of the acquisition of the FPSO, our 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. As of December 31, 2011 the remaining balance under the Advance Payments Agreement was zero. The acquisition was recorded as an increase to oil and gas property. Prior to the acquisition of the FPSO, the Jubilee Unit partners leased the FPSO from MODEC and the lease costs were recorded as oil and gas production costs.

4. Jubilee Field Unitization

The Jubilee Field in Ghana covers an area within both the West Cape Three Points ("WCTP") and Deepwater Tano ("DT") Blocks. Consistent with the Ghanaian Petroleum Law, the WCTP and DT Petroleum Agreements ("PAs") and as required by Ghana's Ministry of Energy, it was agreed the Jubilee Field would be unitized for optimal resource recovery. Kosmos and its partners negotiated a comprehensive unit operating agreement, the Jubilee UUOA, to unitize the Jubilee Field and govern each party's respective rights and duties in the Jubilee Unit. The Jubilee UUOA was executed by all parties and was effective July 16, 2009. The tract participations were 50% for each block. Tullow is the Unit Operator, and Kosmos is the Technical Operator for the development of the Jubilee Field. Pursuant to the terms of the Jubilee UUOA, the tract participations are subject to a process of redetermination. The initial redetermination process was completed on October 14, 2011. Any party to the Jubilee UUOA with more than a 10% Jubilee Unit Interest may call for a second redetermination after December 1, 2013. As a result of the initial redetermination process, the tract participation was

4. Jubilee Field Unitization (Continued)

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 Note 5—Joint Interest Billings) to 24.07710%. The consolidated financial statements are based on these re-determined tract participations for 2011 and 2012. The 2010 financial statements are based on the tract participation in effect during such year. As a result of the change in our Unit Interest in 2011, we recorded increases in joint interest billings receivables, oil and gas properties, notes receivable, inventories, oil and gas production expenses and general and administrative expenses of $67.6 million, $22.1 million, $2.5 million, $0.4 million, $1.6 million and $0.6 million, respectively, and an increase of $94.9 million in accounts payable as of December 31, 2011. Our capital costs related to the increased Unit Interest was paid during 2012. Although the Jubilee Field is unitized, our participating interest in each block outside the Jubilee Unit area did not change. We remain operator of the WCTP Block outside the Jubilee Unit area.

5. Joint Interest Billings

The Company's joint interest billings consist of receivables from partners with interests in common oil and gas properties operated by the Company. Joint interest billings are classified on the face of the consolidated balance sheets as current receivables based on when collection is expected to occur. As of December 31, 2012 and 2011, we had $21.5 million and $199.7 million, respectively, included in current joint interest billings receivable.

EO Group's share of costs under the WCTP PA incurred attributable to its WCTP Block interest were paid by Kosmos until first production. EO Group was required to reimburse Kosmos for all development costs paid on EO Group's behalf upon commencement of production in 2010.

On July 22, 2011, Tullow acquired EO Group's entire 3.5% interest in the WCTP PA, including the correlative interest in the Jubilee Unit. As a result of the transaction, we received full repayment of the long-term joint interest billing receivable related to Jubilee Field development costs we paid on EO Group's behalf. The related valuation allowance of $39.8 million was reversed during the second quarter of 2011. In addition, our participation interest in the Jubilee Unit increased 0.01738%. This resulted from the elimination of EO Group's carry by the other Jubilee owners of Ghana National Petroleum Corporation's ("GNPC") additional paying interest of 3.75% in the Jubilee Unit. Our participating interest in the remainder of the WCTP Block was not changed by the transaction and remains 30.875% (before giving effect to GNPC's optional additional paying interest).

6. Property and Equipment

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

	December 31, 2012	December 31, 2011
	(In thousands)	
Oil and gas properties:		
Proved properties	$ 682,276	$ 607,338
Unproved properties	454,391	294,701
Support equipment and facilities	687,835	600,848
Total oil and gas properties	1,824,502	1,502,887
Less: accumulated depletion	(314,190)	(135,622)
Oil and gas properties, net	1,510,312	1,367,265
Other property	27,316	17,844
Less: accumulated depreciation	(11,866)	(8,068)
Other property, net	15,450	9,776
Property and equipment, net	$1,525,762	$1,377,041

We recorded depletion expense of $178.6 million, $135.5 million and zero for the years ended December 31, 2012, 2011 and 2010, respectively. The Company had depletion costs of nil included in crude oil inventory and other receivables as of December 31, 2012 and 2011.

In November 2012, Kosmos finalized the assignment of a 50% participating interest in our blocks offshore Suriname, Block 42 and Block 45, to Chevron Global Energy Inc. (“Chevron”). Kosmos retains a 50% participating interest in the blocks and remains the operator for the exploration phase of the petroleum contracts. In the fourth quarter of 2012, we received $23.7 million in reimbursement of previously incurred expenses as a result of closing the transaction. Accordingly, exploration expense and general and administrative expense were reduced by $22.7 million and $1.0 million, respectively.

7. Suspended Well Costs

The Company capitalizes exploratory well costs into oil and gas properties until a determination is made that the well has either found proved reserves or is impaired. If proved reserves are found, the capitalized exploratory well costs are reclassified to proved properties. The well costs are charged to expense if the exploratory well is determined to be impaired.

The following table reflects the Company’s capitalized exploratory well costs on completed wells as of and during years ended December 31, 2012, 2011 and 2010. The table excludes $29.6 million,

7. Suspended Well Costs (Continued)

$51.4 million and $56.0 million in costs that were capitalized and subsequently expensed during the same year for the years ended December 31, 2012, 2011 and 2010, respectively.

	Years Ended December 31,		
	2012	2011	2010
	(In thousands)		
Beginning balance	$267,592	$167,511	$114,307
Additions to capitalized exploratory well costs pending the determination of proved reserves	107,527	139,949	55,706
Reclassification due to determination of proved reserves	—	—	—
Capitalized exploratory well costs charged to expense	(2,627)	(39,868)	(2,502)
Ending balance	$372,492	$267,592	$167,511

The following table provides aging of capitalized exploratory well costs based on the date drilling was completed and the number of projects for which exploratory well costs have been capitalized for more than one year since the completion of drilling:

	Years Ended December 31,		
	2012	2011	2010
	(In thousands, except well counts)		
Exploratory well costs capitalized for a period of one year or less	$106,635	$132,838	$ 49,022
Exploratory well costs capitalized for a period one to three years	265,857	134,754	118,489
Ending balance	$372,492	$267,592	$167,511
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	7	3	3

As of December 31, 2012, the projects with exploratory well costs capitalized for more than one year since the completion of drilling are related to Mahogany, Teak-1, Teak-2 and Akasa discoveries in the WCTP Block and the Tweneboa, Enyenra and Ntomme discoveries in the DT Block, which are all in Ghana.

Mahogany—Mahogany, a combined area covering parts of the Mahogany East discovery and the Mahogany Deep discovery, 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 Ministry 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,

7. Suspended Well Costs (Continued)

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 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.

Teak-1 Discovery—Two appraisal wells have been drilled. Following additional appraisal and evaluation, a decision regarding commerciality of the Teak-1 discovery is expected to be made by the WCTP Block partners in 2013. Within six months of such a declaration, a PoD would be prepared and submitted to Ghana's Ministry of Energy, as required under the WCTP PA.

Teak-2 Discovery—We have performed a gauge installation on the well and are reprocessing seismic data. Following additional appraisal and evaluation, a decision regarding commerciality of the Teak-2 discovery is expected to be made by the WCTP Block partners in 2013. Within six months of such a declaration, a PoD would be prepared and submitted to Ghana's Ministry of Energy, as required under the WCTP PA.

Akasa Discovery—We have performed a drill stem test and gauge installation on the well and are analyzing the data. Following additional appraisal and evaluation, a decision regarding commerciality of the Akasa discovery is expected to be made by the WCTP Block partners in 2013. Within six months of such a declaration, a PoD would be prepared and submitted to Ghana's Ministry of Energy, as required under the WCTP PA.

Ntomme Discovery—During 2012, we submitted a declaration of commerciality and PoD over the Tweneboa, Enyenra and Ntomme ("TEN") discoveries and are awaiting approval from the government of Ghana.

Tweneboa Discovery—During 2012, we submitted a declaration of commerciality and PoD over the TEN discoveries and are awaiting approval from the government of Ghana.

Enyenra Discovery—During 2012, we submitted a declaration of commerciality and PoD over the TEN discoveries and are awaiting approval from the government of Ghana.

8. Accounts Payable and Accrued Liabilities

At December 31, 2012 and 2011, $128.9 million and $278.0 million, respectively, were recorded for invoices received but not paid. Accrued liabilities were $41.0 million and $37.2 million at December 31, 2012 and 2011, respectively, and consisted of the following:

	December 31,	
	2012	2011
	(In thousands)	
Accrued liabilities:		
Accrued exploration, development and production	$20,616	$27,666
Accrued general and administrative expenses	5,089	2,159
Accrued taxes other than income	11,124	1,095
Accrued interest	—	1,208
Income taxes	4,192	5,066
	$41,021	$37,194

9. Debt

Facility

In March 2011, the Company secured a $2.0 billion commercial debt facility (the "Facility") from a number of financial institutions and extinguished the then existing commercial debt facilities. The Facility was syndicated to certain participants of the existing facilities, as well as new participants. The Facility supports our oil and gas exploration, appraisal and development programs and corporate activities.

As part of the debt refinancing in March 2011, the repayment of borrowings under the existing facility attributable to financial institutions that did not participate in the Facility was accounted for as an extinguishment of debt, and existing unamortized debt issuance costs attributable to those participants were expensed. For participants in the existing facility that participated in the Facility, an analysis was performed to determine if an exchange of debt instruments with substantially different terms had occurred. As a result, we recorded a $59.6 million loss on the extinguishment of debt. Additionally, we had $61.3 million of deferred financing costs related to the Facility, which were being amortized over the term of the Facility.

In February 2012, the Company amended the Facility. The terms and conditions of the Facility remained consistent with the original terms and conditions, however, the International Finance Corporation entered the Facility. The total commitment under the Facility remained unchanged at $2.0 billion.

In November 2012, the Company again amended the Facility. As part of the amendment, we cancelled $500.0 million of unused commitments from the Facility, reducing the total commitments to $1.5 billion. As a result of the transaction, $5.3 million of deferred financing costs were written off as a loss on extinguishment of debt. As of December 31, 2012, we have $55.8 million of deferred financing costs related to the Facility, which are being amortized over the term of the Facility.

As of December 31, 2012, borrowings under the Facility totaled $1.0 billion and the undrawn availability under the Facility was $340.4 million. Interest expense was $31.6 million, $45.2 million and $39.0 million (net of capitalized interest of $10.3 million, $4.2 million and $9.8 million) and

9. Debt (Continued)

commitment fees were $6.7 million, $8.0 million and $8.2 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Interest is the aggregate of the applicable margin (3.25% to 4.75%, depending on the amount of the Facility that is being utilized and the length of time that has passed from the date the Facility was entered into); LIBOR; and mandatory cost (if any, as defined in the Facility). Interest is payable on the last day of each interest period (and, if the interest period is longer than six months, on the dates falling at six-month intervals after the first day of the interest period). We pay commitment fees on the undrawn and unavailable portion of the total commitments. Commitment fees are equal to 40% per annum of the then-applicable respective margin when a commitment is available for utilization and, equal to 20% per annum of the then-applicable respective margin when a commitment is not available for utilization. We recognize interest expense in accordance with ASC 835—Interest, which requires interest expense to be recognized using the effective interest method. We determined the effective interest rate based on the estimated level of borrowings under the Facility. Accordingly, we recognized $3.6 million, $3.0 million and zero of additional interest expense, which is included in the Facility interest expense amounts disclosed above, during the years ended December 31, 2012, 2011 and 2010, respectively.

The Facility provides a revolving-credit and letter of credit facility for an availability period that expires on May 15, 2014 (in the case of the revolving-credit facility) and on the final maturity date (in the case of the letter of credit facility). The available facility amount is subject to borrowing base constraints and is also constrained by an amortization schedule (once repayments under the Facility begin). Beginning on May 15, 2014, outstanding borrowings will be subject to an amortization schedule. The first required payment could be as early as March 31, 2014, subject to the level of outstanding borrowings and the borrowing base constraints. The Facility has a final maturity date of March 29, 2018.

Kosmos has the right to cancel all the undrawn commitments under the Facility. The amount of funds available to be borrowed under the Facility, also known as the borrowing base amount, is determined each year on March 31 and September 30 as part of a forecast that is prepared by and agreed to by us and the Technical and Modeling Banks. The formula to calculate the borrowing base amount is based, in part, on the sum of the net present values of net cash flows and relevant capital expenditures reduced by certain percentages.

If an event of default exists under the Facility, the lenders can accelerate the maturity and exercise other rights and remedies, including the enforcement of security granted pursuant to the Facility over certain assets held by us.

We were in compliance with the financial covenants contained in the Facility as of the October 15, 2012 (the most recent assessment date).

In connection with the November 2012 amendment to the Facility, certain terms of the Facility were amended as follows:

- the addition of certain financial covenants to allow proceeds from any project permitted to be funded by the Facility to be used, in accordance with certain payment priority provisions, to pay amounts of interest due under, and fees and expenses related to, the $300.0 million revolving credit facility (“Corporate Revolver”—see below) and certain other debt that may be incurred by the Company;

9. Debt (Continued)

- the cancellation of the right of the Company to increase the Facility commitments beyond $2.0 billion (i.e. the cancellation of the uncommitted $1.0 billion accordion);
- to permit (i) subsidiaries of the Company (other than certain of the Company's indirect subsidiaries which hold interests in Kosmos Energy Ghana HC) to incur certain indebtedness and guarantees, and grant certain liens over their assets, and (ii) the Ghana Obligors to guarantee the Corporate Revolver and certain other debt that may be incurred by the Company on a subordinated basis, in each case to the extent permitted by the Amended and Restated Facility Agreement and the intercreditor agreement entered into by us and the lenders under the Facility and the Corporate Revolver;
- the exclusion of certain of the Company's subsidiaries doing business in Cameroon and Morocco from (i) the restrictions contained in the charge granted to the lenders under the Facility over the Company's subsidiary, Kosmos Energy Operating, being the intermediate parent of such subsidiaries doing business in Cameroon and Morocco, and (ii) the receipt of funds from draws under the Facility; and
- to make certain other amendments to the terms of the Facility.

Corporate Revolver

In November 2012, we secured a Corporate Revolver from a number of financial institutions. As of December 31, 2012, we had $260.0 million of commitments under the Corporate Revolver. Availability under the Corporate Revolver may be increased up to $300.0 million if existing lenders increase their commitments or if commitments from new financial institutions are added. The Corporate Revolver is available for all subsidiaries for general corporate purposes and for oil and gas exploration, appraisal and development programs and corporate activities. As of December 31, 2012, we have $8.3 million of deferred financing costs related to the Corporate Revolver, which are being amortized over its term.

As of December 31, 2012, there were no borrowings outstanding under the Corporate Revolver and the undrawn availability under the Corporate Revolver was $260.0 million. Commitment fees were $0.7 million for the year ended December 31, 2012.

Interest is the aggregate of the applicable margin (6.0%); LIBOR; and mandatory cost (if any, as defined in the Corporate Revolver). Interest is payable on the last day of each interest period (and, if the interest period is longer than six months, on the dates falling at six-month intervals after the first day of the interest period). We pay commitment fees on the undrawn portion of the total commitments. Commitment fees for the lenders are equal to 40% per annum of the respective margin when a commitment is available for utilization.

The Corporate Revolver has a 3-year availability period that expires on November 20, 2015. The available amount is not subject to borrowing base constraints. Kosmos has the right to cancel all the undrawn commitments under the Corporate Revolver. The Company is required to repay certain amounts due under the Corporate Revolver with sales of certain subsidiaries or sales of certain assets. If an event of default exists under the Corporate Revolver, the lenders can accelerate the maturity and exercise other rights and remedies, including the enforcement of security granted pursuant to the Corporate Revolver over certain assets held by us.

9. Debt (Continued)

We were in compliance with the financial covenants contained in the Corporate Revolver as of the November 23, 2012 (the most recent assessment date).

At December 31, 2012, the scheduled maturities of debt during the five year period and thereafter are as follows:

	Payments Due by Year (In thousands)					
	2013	2014	2015	2016	2017	Thereafter
Facility(1)	$ —	$191,185	$162,668	$229,481	$333,333	$83,333

(1) The scheduled maturities of debt are based on the level of borrowings and the available borrowing base as of December 31, 2012. Any increases or decreases in the level of borrowings or decreases in the available borrowing base would impact the scheduled maturities of debt during the next five years and thereafter.

10. Derivative Financial Instruments

We use financial derivative contracts to manage exposures to commodity price and interest rate fluctuations. We do not hold or issue derivative financial instruments for trading purposes.

We apply the provisions of ASC 815—Derivatives and Hedging, which require each derivative instrument to be recorded on the balance sheet at fair value. If a derivative has not been designated as a hedge or does not otherwise qualify for hedge accounting, it must be adjusted to fair value through earnings. We do not apply hedge accounting treatment to our oil derivative contracts and, therefore, the change in the fair value of these instruments are recognized in earnings in the period the change occurred. These fair value changes are shown in our statement of operations.

Effective June 1, 2010, we discontinued hedge accounting on all interest rate derivative instruments. Therefore, from that date forward, changes in the fair value of the instruments are recognized in earnings during the period of change. The effective portions of the discontinued hedges as of May 31, 2010, are included in AOCI in the equity section of the accompanying consolidated balance sheets, and are being transferred to earnings when the hedged transaction settles.

Oil Derivative Contracts

We enter into various oil derivative contracts to mitigate our exposure to commodity price risk associated with anticipated future oil production. These contracts currently consist of three-way collars.

We manage market and counterparty credit risk in accordance with our policies and guidelines. In accordance with these policies and guidelines, our management determines the appropriate timing and extent of derivative transactions. We have included an estimate of nonperformance risk in the fair value measurement of our commodity derivative contracts as required by ASC 820—Fair Value Measurements and Disclosures.

10. Derivative Financial Instruments (Continued)

The following table sets forth the volumes in barrels underlying the Company's outstanding oil derivative contracts and the weighted average Dated Brent prices per Bbl for those contracts as of December 31, 2012.

			Weighted Average Price per Bbl			
Term(1)	Type of Contract	MBbl	Deferred Premium	Floor	Ceiling	Calls
2013:						
January—December	Three-way collars	1,500	$4.82	$95.00	$105.00	$125.00
January—December	Three-way collars	1,004	—	87.50	115.00	135.00
January—December	Three-way collars	1,000	—	90.00	115.39	135.00
January—December	Three-way collars	1,000	—	90.08	115.00	135.00
2014:						
January—December	Three-way collars	1,500	1.22	85.00	115.00	140.00

(1) In January 2013, we entered into costless three-way collar contracts for 1.0 MMBbl from January 2014 through December 2014 with a floor price of $85.00 per Bbl, a weighted average ceiling price of $115.01 per Bbl and a call price of $140.00 per Bbl. The three-way collar contracts are indexed to Dated Brent prices.

Provisional Oil Sales

At December 31, 2012, we had sales volumes of 995.9 MBbl priced at an average of $110.51 per Bbl, after differentials, which are subject to final pricing over the next month.

Interest Rate Swaps Derivative Contracts

The following table summarizes our open interest rate swaps, whereby we pay a fixed rate of interest and the counterparty pays a variable LIBOR-based rate, as of December 31, 2012:

Term	Weighted Average Notional Amount	Weighted Average Fixed Rate	Floating Rate
	(In thousands)		
January 2013—December 2013	$227,103	2.06%	6-month LIBOR
January 2014—December 2014	133,434	1.99%	6-month LIBOR
January 2015—December 2015	45,319	2.03%	6-month LIBOR
January 2016—June 2016	12,500	2.27%	6-month LIBOR

Effective June 1, 2010, the Company discontinued hedge accounting on all existing interest rate derivative instruments. Prior to June 1, 2010, any ineffectiveness on the interest rate swaps was immaterial; therefore, no amount was recorded in earnings for ineffectiveness. We have included an estimate of nonperformance risk in the fair value measurement of our interest rate derivative contracts as required by ASC 820—Fair Value Measurements and Disclosures.

10. Derivative Financial Instruments (Continued)

The following tables disclose the Company's derivative instruments as of December 31, 2012 and 2011 and gain/(loss) from derivatives during the years ended December 31 2012, 2011 and 2010:

Type of Contract	Balance Sheet Location	Estimated Fair Value Asset (Liability) December 31, 2012	2011
		(In thousands)	
Derivatives not designated as hedging instruments:			
Derivative asset:			
Commodity	Derivatives assets—current	$ 1,061	$ —
Derivative liability:			
Commodity(1)(2)	Derivatives liabilities—current	(17,005)	(20,303)
Interest rate	Derivatives liabilities—current	(3,372)	(4,104)
Commodity(3)	Derivatives liabilities—long-term	(659)	(4,457)
Interest rate	Derivatives liabilities—long-term	(2,567)	(3,970)
Total derivatives not designated as hedging instruments		$(22,542)	$(32,834)

(1) Includes $3.4 million and $3.2 million, as of December 31, 2012 and December 31, 2011, respectively of cash settlements made on our purchased puts and swaps with calls which were settled in the month subsequent to period end.

(2) Includes deferred premiums of $7.6 million and $22.4 million related to commodity derivative contracts as of December 31, 2012 and December 31, 2011, respectively.

(3) Includes deferred premiums of $2.4 million and $6.6 million related to commodity derivative contracts as of December 31, 2012 and December 31, 2011, respectively.

10. Derivative Financial Instruments (Continued)

Type of Contract	Location of Gain/ (Loss)	Amount of Gain/(Loss) Years Ended December 31, 2012	2011	2010
		(In thousands)		
Derivatives in cash flow hedging relationships:				
Interest rate	AOCI	$ —	$ —	$ 588
Interest rate(1)	Interest expense	(163)	(2,934)	(5,426)
Total derivatives in cash flow hedging relationships		$ (163)	$ (2,934)	$ (4,838)
Derivatives not designated as hedging instruments:				
Commodity(2)	Oil and gas revenue	$ 15,652	$ 3,246	$ —
Commodity	Derivatives, net	(31,490)	(11,777)	(28,319)
Interest rate	Interest expense	(2,464)	(9,548)	(6,967)
Total derivatives not designated as hedging instruments		$(18,302)	$(18,079)	$(35,286)

(1) Amounts were reclassified from AOCI into earnings upon settlement.

(2) Amounts represent the mark-to-market portion of our provisional oil sales contracts.

In accordance with the mark-to-market method of accounting, the Company recognizes changes in fair values of its derivative contracts as gains or losses in earnings during the period in which they occur. The fair value of the effective portion of the interest rate derivative contracts on May 31, 2010, is reflected in AOCI and is being transferred to interest expense over the remaining term of the contracts. The Company expects to reclassify $1.5 million of gains from AOCI to interest expense within the next 12 months. See Note 11—Fair Value Measurements for additional information regarding the Company's derivative instruments.

11. Fair Value Measurements

In accordance with ASC 820—Fair Value Measurements and Disclosures, fair value measurements are based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources, whereas unobservable inputs reflect a company's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. We prioritize the inputs used in measuring fair value into the following fair value hierarchy:

- Level 1—quoted prices for identical assets or liabilities in active markets.
- Level 2—quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs derived principally from or corroborated by observable market data by correlation or other means.

11. Fair Value Measurements (Continued)

- Level 3—unobservable inputs for the asset or liability. The fair value input hierarchy level to which an asset or liability measurement in its entirety falls is determined based on the lowest level input that is significant to the measurement in its entirety.

The following tables present the Company's assets and liabilities that are measured at fair value on a recurring basis as of December 31, 2012 and 2011, for each fair value hierarchy level:

	Fair Value Measurements Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(In thousands)			
December 31, 2012				
Assets:				
Money market accounts	$172,741	$ —	$ —	$172,741
Commodity derivatives	—	1,061	—	1,061
Liabilities:				
Commodity derivatives	—	(17,664)	—	(17,664)
Interest rate derivatives	—	(5,939)	—	(5,939)
Total	$172,741	$(22,542)	$ —	$150,199
December 31, 2011				
Assets:				
Money market accounts(1)	$489,761	$ —	$ —	$489,761
Liabilities:				
Commodity derivatives	—	(24,760)	—	(24,760)
Interest rate derivatives	—	(8,074)	—	(8,074)
Total	$489,761	$(32,834)	$ —	$456,927

(1) As reported in our annual report on Form 10-K for the year ended 2011, the Level 1 fair value measurements excluded $27.5 million of restricted cash. The table above has been revised to properly include this amount.

All fair values have been adjusted for nonperformance risk resulting in a decrease of the commodity derivative liabilities of approximately $0.3 million and a decrease of the interest rate derivatives of approximately of $0.2 million as of December 31, 2012. When the accumulated net present value for all of the derivative contracts with a counterparty is in an asset position, the Company uses the counterparty's credit default swap ("CDS") rates to estimate non-performance risk. When the accumulated net present value for all derivative contracts for a counterparty are in a liability position, we use our internal rate of borrowing to estimate our non-performance risk.

The book values of cash and cash equivalents and restricted cash approximate fair value based on Level 1 inputs. Joint interest billings, oil sales and other receivables, and accounts payable and accrued liabilities approximate fair value due to the short-term nature of these instruments. The carrying values of our debt approximates fair value since they are subject to short-term floating interest rates that approximate the rates available to us for those periods. Our long-term receivables, if any, after any

11. Fair Value Measurements (Continued)

allowances for doubtful accounts approximate fair value. The estimates of fair value of these items are based on Level 2 inputs.

Commodity Derivatives

Our commodity derivatives represent crude oil three-way collars for notional barrels of oil at fixed Dated Brent oil prices. The values attributable to the our oil derivatives are based on (i) the contracted notional volumes, (ii) independent active futures price quotes for Dated Brent, (iii) a credit-adjusted yield curve applicable to each counterparty by reference to the CDS market and (iv) an independently sourced estimate of volatility for Dated Brent. The volatility estimate was provided by certain independent brokers who are active in buying and selling oil options and was corroborated by market-quoted volatility factors. The deferred premium is included in the fair market value of the puts and compound options. See Note 10—Derivative Financial Instruments for additional information regarding the Company's derivative instruments.

Provisional Oil Sales

The value attributable to the provisional oil sales derivative is based on (i) the sales volumes subject to provisional pricing and (ii) an independently sourced forward curve over the term of the provisional pricing period.

Interest Rate Derivatives

As of December 31, 2012 and 2011 the Company had interest rate swaps with notional amounts of $253.6 million and $475.0 million, whereby the Company pays a fixed rate of interest and the counterparty pays a variable LIBOR-based rate. The values attributable to the Company's interest rate derivative contracts are based on (i) the contracted notional amounts, (ii) LIBOR yield curves provided by independent third parties and corroborated with forward active market-quoted LIBOR yield curves and (iii) a credit-adjusted yield curve as applicable to each counterparty by reference to the CDS market.

12. Asset Retirement Obligations

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

	December 31,	
	2012	2011
	(In thousands)	
Asset retirement obligations:		
Beginning asset retirement obligations	$20,670	$16,752
Liabilities incurred during period	1,775	1,702
Revisions in estimated retirement obligations	2,345	—
Liabilities settled during period	—	—
Accretion expense	2,694	2,216
Ending asset retirement obligations	$27,484	$20,670

The Ghanaian legal and regulatory regime regarding oil field abandonment and other environmental matters is evolving. Currently, no Ghanaian environmental regulations expressly require

12. Asset Retirement Obligations (Continued)

that companies abandon or remove offshore assets although under international industry standards we would do so. The Petroleum Law provides for restoration that includes removal of property and abandonment of wells, but further states the manner of such removal and abandonment will be as provided in the Regulations; however, such Regulations have not been promulgated. Under the Environmental Permit for the Jubilee Field, a decommissioning plan will be prepared and submitted to the Ghana Environmental Protection Agency. ASC 410—Asset Retirement and Environmental Obligations requires the Company to recognize this liability in the period in which the liability was incurred. We have recorded an asset retirement obligation for fields that have commenced production. Additional asset retirement obligations will be recorded in the period in which wells within such producing fields are commissioned.

13. Convertible Preferred Units

In May 2011, contemporaneous with Kosmos Energy Ltd.'s IPO, the Series A Convertible Preferred Units ("Series A Units"), Series B Convertible Preferred Units ("Series B Units") and Series C Convertible Preferred Units ("Series C Units") of Kosmos Energy Holdings were exchanged into our common shares based on the pre-offering equity value of such interests. This resulted in the Series A Units, Series B Units and Series C Units being exchanged into 163.1 million; 109.8 million; and 4.8 million common shares of Kosmos Energy Ltd., respectively, or 277.7 million common shares in the aggregate. The common shares have one vote per share and a par value of $0.01. The exchange of the Convertible Preferred Units had the effect of increasing the book value of shareholders' equity by approximately $1.0 billion. Accretion to redemption value of the Convertible Preferred Units was recorded through the date of the exchange. After the date of the exchange, the related accretion on the Convertible Preferred Units ceased to accrue and all rights of the holders with respect to the Convertible Preferred Units terminated, except for the right to receive shares of common shares issuable upon the exchange and the rights entitled to a holder of a common share. Subsequent to this exchange, we have one class of common stock with issued and outstanding shares.

The Convertible Preferred Units were issued in separate series at an issue price of $10 per unit, $25 per unit, and $28.25 per unit, respectively. Under the Fourth Amended and Restated Operating Agreement of Kosmos Energy Holdings, as amended, (the "Agreement") governing Kosmos Energy Holdings, the Convertible Preferred Units received distributions, if any, equal to the "Accreted Value" of the units, prior to any distributions to the common unit holders. The Accreted Value was defined in the Agreement as the unit purchase price plus the preferred return amount per unit equal to 7% of the Accreted Value per annum (compounded quarterly) for the first nine years after the year of Kosmos Energy Holdings' initial operating agreement and 14% of the Accreted Value per annum (compounded quarterly) thereafter, unless a monetization event (as defined in the Agreement) occurred at which time the preferred return would revert to 7%. The holders of the Convertible Preferred Units received the accumulated preferred return upon the consummation of our IPO, as defined in the Agreement. The accumulated preferred return on the Convertible Preferred Units was recorded through the date of the offering. The amount was applied to additional paid-in capital first, with the remaining amount applied to the accumulated deficit. The Convertible Preferred Units were classified as mezzanine equity at December 31, 2010, as Kosmos Energy Holdings could not solely control the type of consideration issuable on the exchange and the Convertible Preferred Unit holders controlled Kosmos Energy Holdings' Board of Directors.

13. Convertible Preferred Units (Continued)

We recorded accretion on the Convertible Preferred Units of $24.4 million and $77.3 million for the years ended December 31, 2011 and 2010, respectively.

14. Equity-based Compensation

Profit Units

Prior to our corporate reorganization, Kosmos Energy Holdings issued common units designated as profit units with a threshold value ranging from $0.85 to $90 to employees, management and directors. Profit units, the defined term in the related agreements, were equity awards that were measured on the grant date and expensed over a vesting period of four years. Founding management and directors vested 20% as of the date of issuance and an additional 20% on the anniversary date for each of the next four years. Profit units issued to employees vested 50% on the second and fourth anniversaries of the issuance date.

The following is a summary of the Kosmos Energy Holdings' profit unit activity immediately prior to the corporate reorganization:

	Profit Units	Weighted-Average Grant-Date Fair Value
	(In thousands)	
Outstanding at December 31, 2010	13,910	$ 1.76
Granted	1,783	15.71
Relinquished	(2,503)	0.12
Outstanding at May 16, 2011	13,190	3.96

A summary of the status of the Kosmos Energy Holdings' unvested profit units immediately prior to the corporate reorganization were as follows:

	Unvested Profit Units	Weighted-Average Grant-Date Fair Value
	(In thousands)	
Outstanding at December 31, 2010	3,464	$ 1.60
Granted	1,783	15.71
Vested	(1,066)	1.09
Relinquished	(1,253)	0.10
Outstanding at May 16, 2011	2,928	11.02

Effective December 31, 2010, James C. Musselman retired as the Company's Chairman and Chief Executive Officer. The Company entered into a retirement agreement with Mr. Musselman on December 17, 2010. Pursuant to the retirement agreement, 1.2 million profit units of Kosmos Energy Holdings that were unvested as of his retirement date became fully vested as of such date, resulting in unit-based compensation of $11.5 million in the fourth quarter of 2010.

14. Equity-based Compensation (Continued)

Total profit unit compensation expense recognized in income was zero, $1.2 million and $13.8 million for the years ended December 31, 2012, 2011 and 2010, respectively. There was no income tax benefit realized related to the profit unit compensation expense.

The significant assumptions used to calculate the fair values of the profit units granted over the past three years, as calculated using a binomial tree, were as follows: no dividend yield, expected volatility ranging from approximately 25% to 66%; risk-free interest rate ranging from 1.3% to 5.1%; expected life ranging from 1.2 to 8.1 years; and projected turnover rate of 7.0% for employees and none for management.

Restricted Stock Awards and Restricted Stock Units

As part of the corporate reorganization, vested profit units were exchanged for 31.7 million common shares of Kosmos Energy Ltd., unvested profit units were exchanged for 10.0 million restricted stock awards and the $90 profit units were cancelled. Based on the terms and conditions of the corporate reorganization, the exchange of profit units for common shares of Kosmos Energy Ltd. resulted in no incremental compensation costs.

In April 2011, the Board of Directors approved a Long-Term Incentive Plan (the "LTIP"), which provides for the granting of incentive awards in the form of stock options, stock appreciation rights, restricted stock awards, restricted stock units, among other award types. The LTIP provides for the issuance of 24.5 million shares pursuant to awards under the plan, in addition to the 10.0 million restricted stock awards exchanged for unvested profit units.

The following table shows the number of shares available for issuance pursuant to awards under the Company's LTIP at December 31, 2012:

	Shares (In thousands)
Approved and authorized awards(1)	24,503
Awards issued after May 16, 2011	(18,507)
Awards forfeited(2)	201
Awards available for future grant	6,197

(1) Excludes 10.0 million restricted stock awards that were exchanged for unvested profit units.

(2) Excludes forfeited restricted stock awards issued in connection with our initial public offering, which include the May 18, 2011 and June 15, 2011 award tranches, as awards forfeited from these tranches are not available for future grant.

We record compensation expense equal to the fair value of share-based payments over the vesting periods of the LTIP awards. We recorded compensation expense from awards granted under our LTIP of $83.4 million and $49.8 million during the years ended December 31, 2012 and 2011, respectively. The total tax benefit for the years ended December 31, 2012 and 2011 was $28.8 million and $17.3 million, respectively. Additionally, we expensed a tax shortfall related to equity-based compensation of $8.1 million and zero for the years ended December 31, 2012 and 2011, respectively.

14. Equity-based Compensation (Continued)

Subsequent to May 16, 2011, the Company granted both restricted stock awards and restricted stock units with service vesting criteria and granted both restricted stock awards and restricted stock units with a combination of market and service vesting criteria under the LTIP.

The following table reflects the outstanding restricted stock awards as of December 31, 2012:

	Service Vesting Restricted Stock Awards (In thousands)	Weighted-Average Grant-Date Fair Value	Market / Service Vesting Restricted Stock Awards (In thousands)	Weighted-Average Grant-Date Fair Value
Outstanding at May 16, 2011	—	$ —	—	$ —
Exchanged	10,033	2.79	—	—
Granted	11,314	18.10	3,522	13.30
Forfeited	(650)	2.70	—	—
Vested	(3,502)	0.36	—	—
Outstanding at December 31, 2011	17,195	13.36	3,522	13.21
Granted	590	12.05	303	9.45
Forfeited	(994)	13.87	(291)	12.68
Vested	(6,893)	8.05	—	—
Outstanding at December 31, 2012	9,898	16.92	3,534	12.93

The following table reflects the outstanding restricted stock units as of December 31, 2012:

	Service Vesting Restricted Stock Units (In thousands)	Weighted-Average Grant-Date Fair Value	Market / Service Vesting Restricted Stock Units (In thousands)	Weighted-Average Grant-Date Fair Value
Outstanding at May 16, 2011	—	$ —	—	$ —
Granted	—	—	—	—
Forfeited	—	—	—	—
Vested	—	—	—	—
Outstanding at December 31, 2011	—	—	—	—
Granted	1,070	10.60	854	15.81
Forfeited	(47)	10.88	(29)	15.81
Vested	—	—	—	—
Outstanding at December 31, 2012	1,023	10.59	825	15.81

14. Equity-based Compensation (Continued)

As of December 31, 2012, total equity-based compensation to be recognized on unvested restricted stock awards and restricted stock units is $174.0 million over a weighted average period of 2.55 years.

For equity-based compensation awards, compensation expense is recognized in the Company's financial statements over the awards' vesting periods based on their grant date fair value. The Company utilizes (i) the closing stock price on the date of grant to determine the fair value of service vesting restricted stock awards and service vesting restricted stock units and (ii) a Monte Carlo simulation to determine the fair value of restricted stock awards and restricted stock units with a combination of market and service vesting criteria.

For restricted stock awards with a combination of market and service vesting criteria, the number of common shares to be issued is determined by comparing the Company's total shareholder return with the total shareholder return of a predetermined group of peer companies over the performance period and can vest in up to 100% of the awards granted. The grant date fair value of these awards ranged from $6.70 to $13.57 per award. The Monte Carlo simulation model utilizes multiple input variables that determine the probability of satisfying the market condition stipulated in the award grant and calculates the fair value of the award. The expected volatility utilized in the model was estimated using our historical volatility and the historical volatilities of our peer companies and ranged from 41.3% to 56.7%. The risk-free interest rate was based on the U.S. treasury rate for a term commensurate with the expected life of the grant and ranged from 0.5% to 1.1%.

For restricted stock units with a combination of market and service vesting criteria, the number of common shares to be issued is determined by comparing the Company's total shareholder return with the total shareholder return of a predetermined group of peer companies over the performance period and can vest in up to 200% of the awards granted. The grant date fair value of these awards was $15.81 per award. The Monte Carlo simulation model utilizes multiple input variables that determine the probability of satisfying the market condition stipulated in the award grant and calculates the fair value of the award. The expected volatility utilized in the model was estimated using our historical volatility and the historical volatilities of our peer companies and was 54.0%. The risk-free interest rate was based on the U.S. treasury rate for a term commensurate with the expected life of the grant and was 0.5%.

15. Income Taxes

Kosmos Energy Ltd. is a Bermuda company that is not subject to taxation at the corporate level. We provide for income taxes based on the laws and rates in effect in the countries in which our operations are conducted. The relationship between our pre-tax income or loss from continuing operations and our income tax expense or benefit varies from period to period as a result of various factors which include changes in total pre-tax income or loss, the jurisdictions in which our income is earned and the tax laws in those jurisdictions.

15. Income Taxes (Continued)

The components of income (loss) before income taxes were as follows:

	Years Ended December 31,		
	2012	2011	2010
		(In thousands)	
Bermuda	$ (11,651)	$ (4,826)	$ —
United States	14,342	8,808	1,476
Foreign—other	31,465	95,061	(324,256)
Income (loss) before income taxes	$ 34,156	$ 99,043	$(322,780)

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

	Years Ended December 31,		
	2012	2011	2010
		(In thousands)	
Current:			
Bermuda	$ —	$ —	$ —
United States	21,148	20,229	506
Foreign—other	—	—	—
Total current	21,148	20,229	506
Deferred:			
Bermuda	—	—	—
United States	(7,908)	(16,857)	(143)
Foreign—other	87,944	73,314	(77,471)
Total deferred	80,036	56,457	(77,614)
Income tax expense (benefit)	$101,184	$ 76,686	$ (77,108)

15. Income Taxes (Continued)

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

	Years Ended December 31,		
	2012	2011	2010
		(In thousands)	
Tax at Bermuda statutory rate	$ —	$ —	$ —
Foreign income taxed at different rates	73,277	52,922	(74,841)
Change in valuation allowance	14,103	19,362	(3,611)
Non-deductible and other items	5,669	4,402	1,344
Tax shortfall on equity-based compensation	8,135	—	—
Total tax expense	$101,184	$ 76,686	$ (77,108)
Effective tax rate(1)	296.2%	77.4%	23.9%

(1) The effective tax rate during the years ended December 31, 2012, 2011 and 2010 was also impacted by losses of $168.5 million, $86.2 million and $106.5 million, respectively, incurred in jurisdictions in which we are not subject to taxes and, therefore, do not generate any income tax benefits.

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

15. Income Taxes (Continued)

differences become deductible. The tax effects of significant temporary differences giving rise to deferred tax assets and liabilities are as follows:

	December 31. 2012	December 31. 2011
	(In thousands)	
Deferred tax assets:		
Ghana foreign capitalized operating expenses	$ 4,240	$ 6,355
Foreign net operating losses	41,569	92,154
Equity compensation	26,033	17,282
Unrealized derivative losses	5,714	7,622
Other	11,047	7,354
Total deferred tax assets	88,603	130,767
Valuation allowance	(63,605)	(49,502)
Total deferred tax assets, net	24,998	81,265
Deferred tax liabilities:		
Depletion, depreciation and amortization related to property and equipment	(84,405)	(60,635)
Total deferred tax liabilities	(84,405)	(60,635)
Net deferred tax asset (liability)	$ (59,407)	$ 20,630

The Company had net deferred tax assets in Ghana totaling approximately $20.6 million at December 31, 2009 primarily relating to capitalized operating expenses incurred during the development phase of the Jubilee Field. Prior to the commencement of production from the Jubilee Field on November 28, 2010, the Company maintained a full valuation allowance against its net deferred tax asset. However, at December 31, 2010, the Company determined that it was more likely than not that the deferred tax asset for its Ghana operations would be recognized, resulting in the valuation allowance no longer being necessary. Therefore, we released the $20.6 million deferred tax asset valuation allowance and recognized $56.9 million of deferred tax assets generated during 2010.

As of December 31, 2012, our Ghana operations are in a net deferred tax liability position and we expect to utilize the remainder of the Ghana net operating loss carryforward during 2013.

The Company has recorded a full valuation allowance against the net deferred tax assets in Cameroon, Morocco, Suriname and Mauritania. The net change in the valuation allowance of $14.1 million is due to the additional losses generated in those countries.

The Company has entered into various petroleum agreements in Morocco. These agreements provide for a tax holiday, at a 0% tax rate, for a period of 10 years beginning on the date of first production. The Company currently has recorded deferred tax assets of $20.4 million, recorded at the Moroccan statutory rate of 30%, with an offsetting valuation allowance of $20.4 million. We will re-evaluate our deferred tax position upon entering the tax holiday period and at such time may reduce the statutory rate applied to the deferred tax assets in Morocco to the extent those deferred tax assets are realized within the tax holiday period.

15. Income Taxes (Continued)

The Company has foreign net operating loss carryforwards of $72.7 million, which began to expire in 2012, and $49.2 million, which do not expire.

A subsidiary of the Company files a U.S. federal income tax return and a Texas margin tax return. In addition to the United States, the Company files income tax returns in the countries in which the Company operates. The Company is open to U.S. federal income tax examinations for tax years 2009 through 2012 and to Texas margin tax examinations for the tax years 2008 through 2012. In addition, the Company is open to income tax examinations for years 2004 through 2012 in its significant other foreign jurisdictions (Ghana, Cameroon and Morocco).

As of December 31, 2012, the Company had no material uncertain tax positions. The Company's policy is to recognize potential interest and penalties related to income tax matters in income tax expense, but has had no need to accrue any to date.

16. Net Income (Loss) Per Share

In the calculation of basic net income per common share attributable to common shareholders, participating securities are allocated earnings based on actual dividend distributions received plus a proportionate share of undistributed net income attributable to common shareholders, if any, after recognizing distributed earnings. We calculate basic net income per common share attributable to common shareholders under the two-class method. The Company's participating securities, which consist solely of service vesting restricted stock awards (See See Note 14—Equity-based Compensation), do not participate in undistributed net losses because they are not contractually obligated to do so. The computation of diluted net income (loss) per share attributable to common shareholders reflects the potential dilution that could occur if securities or other contracts to issue common shares that are dilutive were exercised or converted into common shares or resulted in the issuance of common shares that would then share in the earnings of the Company. During periods in which the Company realizes a loss from continuing operations attributable to common shareholders, securities would not be dilutive to net loss per share and conversion into common shares is assumed not to occur. Diluted net income (loss) per share attributable to common shareholders is calculated under both the two-class method and the treasury stock method and the more dilutive of the two calculations is presented.

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

16. Net Income (Loss) Per Share (Continued)

In the periods prior to our Corporate Reorganization, we do not calculate 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 the year ended December 31, 2011, we have presented net income per share attributable to common shareholders from the date of our Corporate Reorganization, May 16, 2011 to December 31, 2011.

(In thousands, except per share data)	Year Ended December 31, 2012	May 16, 2011 - December 31, 2011
Net loss attributable to common shareholders/ unit holders for the year ended December 31, 2011		$ (2,085)
Net loss attributable to unit holders for the period from January 1, 2011 to May 15, 2011		(38,191)
Net income attributable to common shareholders for the period May 16, 2011 to December 31, 2011		$ 36,106
Numerator:		
Net income (loss) attributable to common shareholders	$ (67,028)	$ 36,106
Less: Basic income allocable to participating securities(1)	—	1,643
Basic net income (loss) allocable to common shareholders	(67,028)	34,463
Diluted adjustments to income allocable to participating securities(1)	—	9
Diluted net income (loss) allocable to common shareholders	$ (67,028)	$ 34,472
Denominator:		
Weighted average number of shares used to compute net income (loss) per share:		
Basic	371,847	368,474
Restricted stock awards(1)(2)	—	133
Diluted	371,847	368,607
Net income (loss) per share attributable to common shareholders:		
Basic	$ (0.18)	$ 0.09
Diluted	$ (0.18)	$ 0.09

(1) Our service vesting restricted stock awards represent participating securities because they participate in nonforfeitable dividends with common equity owners. Income allocable to participating securities represents the distributed and undistributed earnings attributable to the participating securities. Our restricted stock awards with market and service vesting criteria and all restricted stock units are not considered to be participating securities and,

16. Net Income (Loss) Per Share (Continued)

therefore, are excluded from the basic net income (loss) per common share calculation. Our service vesting restricted stock awards do not participate in undistributed net losses and, therefore, are excluded from the basic net income (loss) per common share calculation in periods we are in a net loss position.

(2) For the year ended December 31, 2012 and for the period from May 16, 2011 through December 31, 2011, we excluded 15.3 million and 20.5 million outstanding restricted stock awards, respectively, from the computations of diluted net income per share because the effect would have been anti-dilutive.

17. Commitments and Contingencies

We are involved in litigation, regulatory examinations and administrative proceedings primarily arising in the ordinary course of our business in jurisdictions in which we do business. Although the outcome of these matters cannot be predicted with certainty, management believes none of these matters, either individually or in the aggregate, would have a material effect upon the Company's financial statements.

The Company leases facilities under various operating leases that expire through 2019, including our office space. Rent expense under these agreements, was $4.3 million, $2.3 million and $1.4 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Future minimum rental commitments under these leases at December 31, 2012, are as follows:

	Payments Due By Year(1)						
	Total	2013	2014	2015	2016	2017	Thereafter
	(In thousands)						
Operating leases	$21,562	$2,821	$2,921	$3,022	$3,122	$3,223	$6,453

(1) Does not include purchase commitments for jointly owned fields and facilities where we are not the operator and excludes commitments for exploration activities, including well commitments, in our petroleum contracts.

18. Subsequent Event

Drilling of the Sapele-1 exploration well was completed in February 2013. The well is not considered a productive well and accordingly will be plugged and abandoned. The amount of costs related to this well which were capitalized at December 31, 2012 were immaterial.

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Supplemental Oil and Gas Data (Unaudited)

Net proved oil and gas reserve estimates presented were prepared by Netherland, Sewell & Associates, Inc. ("NSAI"), independent petroleum engineers located in Dallas, Texas, adjusted for imbalances. NSAI have prepared the reserve estimates presented herein and meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to independent reserve engineers for their reserves estimation process.

Net Proved Developed and Undeveloped Reserves

The following table is a summary of net proved developed and undeveloped oil and gas reserves to Kosmos' interest in the Jubilee Field in Ghana.

	Oil (MMBbl)	Gas (Bcf)	Total (MMBoe)
Net proved undeveloped reserves at December 31, 2009	52	—	52
Extensions and discoveries	—	22	4
Production	—	—	—
Purchases of minerals-in-place	—	—	—
Net proved developed and undeveloped reserves at December 31, 2010	52	22	56
Extensions and discoveries	—	—	—
Production	(6)	(2)	(6)
Revisions in estimates(1)	1	4	1
Purchases of minerals-in-place	—	—	—
Net proved developed and undeveloped reserves at December 31, 2011(2)	47	24	51
Extensions and discoveries	—	—	—
Production	(6)	(1)	(6)
Revisions in estimates(3)	1	(14)	(2)
Purchases of minerals-in-place	—	—	—
Net proved developed and undeveloped reserves at December 31, 2012	42	9	43
Proved developed reserves(2)			
December 31, 2010	35	18	38
December 31, 2011	23	16	26
December 31, 2012	32	9	33
Proved undeveloped reserves(2)			
December 31, 2010	17	4	18
December 31, 2011	25	8	26
December 31, 2012	10	1	10

(1) The increase in estimated oil reserves is due to an increase in our Jubilee Field unit interest (see Note 4—Jubilee Field Unitization). The estimated increase in gas reserves

represents our increased Jubilee Field unit interest and an increase in estimated gas reserves to be utilized as fuel gas for the FPSO.

(2) The sum of proved developed reserves and proved undeveloped reserves may not add to net proved developed and undeveloped reserves due to rounding.

(3) The estimated decrease in gas reserves represents a decrease in estimated gas reserves to be utilized as fuel gas for the FPSO.

Net proved reserves were calculated utilizing the twelve month unweighted arithmetic average of the first-day-of-the-month oil price for each month for Brent crude in the period January through December 2012. The average Brent crude price of $111.21 per barrel is adjusted for crude handling, transportation fees, quality, and a regional price differential. Based on the crude quality, these adjustments are estimated to be an additional $1.40 per barrel; therefore, the adjusted oil price is $112.61 per barrel. This oil price is held constant throughout the lives of the properties. There is no gas price used because gas reserves are consumed in operations as fuel.

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

Capitalized Costs Related to Oil and Gas Activities

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

	Ghana	Other(1)	Total
		(In thousands)	
As of December 31, 2012			
Unproved properties	$ 421,918	$32,473	$ 454,391
Proved properties	1,370,111	—	1,370,111
	1,792,029	32,473	1,824,502
Accumulated depletion, depreciation and amortization	(314,190)	—	(314,190)
Net capitalized costs	$1,477,839	$32,473	$1,510,312
As of December 31, 2011			
Unproved properties	$ 290,736	$ 3,966	$ 294,702
Proved properties	1,208,185	—	1,208,185
	1,498,921	3,966	1,502,887
Accumulated depletion, depreciation and amortization	(135,622)	—	(135,622)
Net capitalized costs	$1,363,299	$ 3,966	$1,367,265

(1) Includes Africa, excluding Ghana, and South America.

Costs Incurred in Oil and Gas Activities

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

	Ghana	Other(1)	Total
		(In thousands)	
Year ended December 31, 2012			
Property acquisition:			
Unproved	$ —	$ 5,000	$ 5,000
Proved	—	—	—
Exploration	173,463	78,939	252,402
Development	161,925	—	161,925
Total costs incurred	$335,388	$83,939	$419,327
Year ended December 31, 2011			
Property acquisition:			
Unproved	$ —	$ 1,932	$ 1,932
Proved	—	—	—
Exploration	187,272	33,758	221,030
Development	410,035	—	410,035
Total costs incurred	$597,307	$35,690	$632,997
Year ended December 31, 2010			
Property acquisition:			
Unproved	$ —	$ —	$ —
Proved	—	—	—
Exploration	109,624	32,304	141,928
Development	325,975	—	325,975
Total costs incurred	$435,599	$32,304	$467,903

(1) Includes Africa, excluding Ghana, and South America.

Standardized Measure for Discounted Future Net Cash Flows

The following table provides projected future net cash flows based on the twelve month unweighted arithmetic average of the first-day-of-the-month oil price for Brent crude in the period January through December 2012. The average Brent crude price of $111.21 per barrel is adjusted for crude handling, transportation fees, quality, and a regional price differential. Based on the crude quality, these adjustments are estimated to be an additional $1.40 per barrel; therefore, the adjusted oil price is $112.61 per barrel. Because prices used in the calculation are average prices for that year, the standardized measure could vary significantly from year to year based on market conditions that occur.

The projection should not be interpreted as representing the current value to Kosmos. Material revisions to estimates of proved reserves may occur in the future; development and production of the reserves may not occur in the periods assumed; actual prices realized are expected to vary significantly from those used; and actual costs may vary. Kosmos' investment and operating decisions are not based on the information presented, but on a wide range of reserve estimates that include probable as well as proved reserves and on a wide range of different price and cost assumptions.

The standardized measure is intended to provide a better means to compare the value of Kosmos' proved reserves at a given time with those of other oil producing companies than is provided by comparing raw proved reserve quantities.

	Ghana (In millions)
At December 31, 2012	
Future cash inflows	$ 4,708
Future production costs	(599)
Future development costs	(429)
Future Ghanaian tax expenses(1)	(1,068)
Future net cash flows	2,612
10% annual discount for estimated timing of cash flows	(540)
Standardized measure of discounted future net cash flows	$ 2,072
At December 31, 2011	
Future cash inflows	$ 5,230
Future production costs	(655)
Future development costs	(698)
Future Ghanaian tax expenses(1)	(1,027)
Future net cash flows	2,850
10% annual discount for estimated timing of cash flows	(834)
Standardized measure of discounted future net cash flows	$ 2,016
At December 31, 2010	
Future cash inflows	$ 4,141
Future production costs	(1,140)
Future development costs	(342)
Future Ghanaian tax expenses(1)	(618)
Future net cash flows	2,041
10% annual discount for estimated timing of cash flows	(511)
Standardized measure of discounted future net cash flows	$ 1,530

(1) Standardized Measure includes the effects of both future income tax expense related to the Company's proved oil and gas reserves levied at a corporate parent and intermediate subsidiary level on future net revenues and future tax expense levied at an asset level (in the Company's case, future Ghanaian tax expense levied under the WCTP and DT PAs). As the Company has been a tax exempted company incorporated pursuant to the laws of the Cayman Islands to date and is now a tax exempted company incorporated pursuant to the laws of Bermuda since the completion of the corporate reorganization, 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, the Company has not been and does not expect to be subject to future income tax expense related to its proved oil and gas reserves levied at a corporate parent or intermediate subsidiary level. Accordingly, the Company's Standardized Measure for the years ended December 31, 2012, 2011and 2010, respectively, only reflect the effects of future Ghanaian tax expense levied under the WCTP and DT PAs.

Changes in the Standardized Measure for Discounted Cash Flows

	Ghana
	(In millions)
Balance at December 31, 2009	$ 698
Net changes in prices	1,055
Net changes in production costs	(150)
Net changes in development costs	288
Extensions and discoveries	(12)
Net changes in Ghanaian tax expenses(1)	(267)
Accretion of discount	(82)
Balance at December 31, 2010	$1,530
Sales and Transfers 2011	(583)
Net changes in prices and costs	1,547
Previous estimated development costs incurred during the period	175
Net changes in development costs	(489)
Revisions of previous quantity estimates	2
Changes in production timing	(66)
Net changes in Ghanaian tax expenses(1)	(248)
Accretion of discount	199
Redetermination(2)	92
Changes in timing and other	(143)
Balance at December 31, 2011	$2,016
Sales and Transfers 2012	(573)
Net changes in prices and costs	32
Previously estimated development costs incurred during the period	158
Net changes in development costs	122
Revisions of previous quantity estimates	49
Net changes in Ghanaian tax expenses(1)	(105)
Accretion of discount	274
Changes in timing and other	99
Balance at December 31, 2012	$2,072

(1) Standardized Measure includes the effects of both future income tax expense related to the Company's proved oil and gas reserves levied at a corporate parent and intermediate subsidiary level on future net revenues and future tax expense levied at an asset level (in the Company's case, future Ghanaian tax expense levied under the WCTP and DT PAs). As the Company has been a tax exempted company incorporated pursuant to the laws of the Cayman Islands to date and is now a tax exempted company incorporated pursuant to the laws of Bermuda since the completion of the corporate reorganization, 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, the Company has not been and does not expect to be subject to future income tax expense related to its proved oil and gas reserves levied at a corporate parent or intermediate subsidiary level. Accordingly, the Company's Standardized Measure for the years ended December 31, 2012, 2011and 2010, respectively, only reflect the effects of future Ghanaian tax expense levied under the WCTP and DT PAs.

(2) Relates to an increase in our Jubilee Field unit interest (see Note 4—Jubilee Field Unitization).

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Supplemental Quarterly Financial Information (Unaudited)

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
	(In thousands, except per share data)			
2012				
Revenues	$116,547	$112,671	$223,237	$219,754
Expenses	137,802	114,993	233,564	151,694
Net income (loss)	(37,541)	(24,843)	(36,250)	31,606
Net income (loss) attributable to common shareholders	(37,541)	(24,843)	(36,250)	31,606
Net income (loss) attributable to common shareholders per share:				
Basic	(0.10)	(0.07)	(0.10)	0.08
Diluted	(0.10)	(0.07)	(0.10)	0.08
2011				
Revenues	$ 95,410	$126,853	$232,845	$221,672
Expenses	163,572	124,409	130,588	159,168
Net income (loss)	(54,651)	(9,091)	51,776	34,323
Net income (loss) attributable to common shareholders/unit holders	(71,498)	(16,686)	51,776	34,323
Net income (loss) attributable to common shareholders/unit holders per share:				
Basic (the quarter ended June 30, represents the period from May 16, 2011 to June 30, 2011)	N/A	(0.14)	0.13	0.09
Diluted (the quarter ended June 30, represents the period from May 16, 2011 to June 30, 2011)	N/A	(0.14)	0.13	0.09

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) was performed under the supervision and with the participation of the Company's management, including our Chief Executive Officer and Chief Financial Officer. This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the SEC reports we file or submit under the Exchange Act is accurate, complete and timely. However, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. The design of a control system must reflect the fact that there are resource constraints, and the benefit of controls must be considered relative to their costs. Consequently, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. Based upon this evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2012, in ensuring that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, including that such information is accumulated and communicated to the Company's management, including our Chief Executive Officer and our Chief Financial Officer, to allow timely decisions regarding required disclosure.

Evaluation of Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during our most recent fiscal quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control has been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external purposes in accordance with U.S. generally accepted accounting principles. All internal control systems have inherent limitations, including the possibility of human error and the possible circumvention of or overriding of controls. The design of an internal control system is also based in part upon assumptions and judgments made by management. As a result, even an effective system of internal controls can provide no more than reasonable assurance with respect to the fair presentation of financial statements and the processes under which they were prepared. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that internal control may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, we assessed the effectiveness of our internal control over financial reporting as of the end of the period covered by this report based on the framework in "Internal Control—Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, our Chief Executive Officer and our Chief

Financial Officer concluded that our internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of our financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

Ernst & Young LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this annual report on Form 10-K, has issued an attestation report on the effectiveness of internal control over financial reporting as of December 31, 2012 which is included in "Item 8. Financial Statements and Supplementary Data."

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information as to Item 10 will be set forth in the Proxy Statement for the Annual Meeting of Shareholders to be held during June 2013 and is incorporated herein by reference.

Item 11. Executive Compensation

Information as to Item 11 will be set forth in the Proxy Statement for the Annual Meeting of Shareholders to be held during June 2013 and is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information as to Item 12 will be set forth in the Proxy Statement for the Annual Meeting of Shareholders to be held during June 2013 and is incorporated herein by reference.

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

Information as to Item 13 will be set forth in the Proxy Statement for the Annual Meeting of Shareholders to be held during June 2013 and is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services

Information as to Item 14 will be set forth in the Proxy Statement for the Annual Meeting of Shareholders to be held during June 2013 and is incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) The following documents are filed as part of this report:

(1) Financial statements

The financial statements filed as part of the Annual Report on Form 10-K are listed in the accompanying index to consolidated financial statements in Item 8, Financial Statements and Supplementary Data.

(2) Financial statement schedules

Schedule I—Condensed Parent Company Financial Statements

Under the terms of agreements governing the indebtedness of subsidiaries of Kosmos Energy Ltd. for 2012, 2011 and 2010 (collectively "KEL," the "Parent Company"), such subsidiaries are restricted from making dividend payments, loans or advances to KEL. Schedule I of Article 5-04 of Regulation S-X requires the condensed financial information of the Parent Company to be filed when the restricted net assets of consolidated subsidiaries exceed 25 percent of consolidated net assets as of the end of the most recently completed fiscal year.

The following condensed parent-only financial statements of KEL have been prepared in accordance with Rule 12-04, Schedule I of Regulation S-X and included herein. The Parent Company's 100% investment in its subsidiaries has been recorded using the equity basis of accounting in the accompanying condensed parent-only financial statements. The condensed financial statements should be read in conjunction with the consolidated financial statements of Kosmos Energy Ltd. and subsidiaries and notes thereto.

The terms "Kosmos," the "Company," and similar terms when used in the present tense or prospectively or for historical periods since May 16, 2011 refer to Kosmos Energy Ltd. and its wholly owned subsidiaries and for historical periods prior to May 16, 2011 refer to Kosmos Energy Holdings and its wholly owned subsidiaries, unless the context indicates otherwise. Certain prior period amounts have been reclassified to conform with the current year presentation. Such reclassifications had no impact on our reported net income, current assets, total assets, current liabilities, total liabilities or shareholders equity.

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CONDENSED PARENT COMPANY BALANCE SHEETS

(In thousands, except share data)

	December 31, 2012	December 31, 2011
Assets		
Current assets:		
Cash and cash equivalents	$ 132,574	$ 352,872
Receivables from subsidiaries	373	—
Prepaid expenses and other	375	394
Total current assets	133,322	353,266
Investment in subsidiaries at equity	888,473	668,618
Deferred financing costs, net of accumulated amortization of $283 and zero, respectively	7,992	—
Total assets	$1,029,787	$1,021,884
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable to subsidiaries	$ —	$ 1,158
Accrued liabilities	881	—
Total current liabilities	881	1,158
Shareholders' equity:		
Preference shares, $0.01 par value; 200,000,000 authorized shares; zero issued at December 31, 2012 and 2011	—	—
Common shares, $0.01 par value; 2,000,000,000 authorized shares; 391,423,703 and 390,530,946 issued at December 31, 2012 and 2011, respectively	3,914	3,905
Additional paid-in capital	1,712,880	1,629,453
Accumulated deficit	(683,176)	(616,148)
Accumulated other comprehensive income	3,685	3,522
Treasury stock, at cost, 2,731,941 and 649,818 shares at December 31, 2012 and 2011, respectively	(8,397)	(6)
Total shareholders' equity	1,028,906	1,020,726
Total liabilities and shareholders' equity	$1,029,787	$1,021,884

KOSMOS ENERGY LTD.

CONDENSED PARENT COMPANY STATEMENTS OF OPERATIONS

(In thousands)

	December 31,		
	2012	2011	2010
Revenues and other income:			
Oil and gas revenue	$ —	$ —	$ —
Interest income	400	248	44
Total revenues and other income	400	248	44
Costs and expenses:			
General and administrative	93,472	54,442	21,187
General and administrative—related party	(82,370)	(49,378)	16,830
Amortization—deferred financing costs	283	—	—
Interest expense	659	—	—
Other expenses, net	6	10	2
Equity in (earnings) losses of subsidiaries	55,378	(27,183)	207,697
Total costs and expenses	67,428	(22,109)	245,716
Income (loss) before income taxes	(67,028)	22,357	(245,672)
Income tax expense	—	—	—
Net income (loss)	$(67,028)	$ 22,357	$(245,672)

KOSMOS ENERGY LTD.

CONDENSED PARENT COMPANY STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31,		
	2012	2011	2010
Operating activities			
Net income (loss)	$ (67,028)	$ 22,357	$(245,672)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Equity in (earnings) losses of subsidiaries	55,378	(27,183)	207,697
Equity-based compensation	83,423	50,966	13,791
Amortization	283	—	—
Changes in assets and liabilities:			
(Increase) decrease in prepaid expenses and other	19	(394)	15
(Increase) decrease due to/from related party	(1,531)	1,158	3,878
Increase (decrease) in accrued liabilities	136	—	(213)
Net cash provided by (used in) operating activities	70,680	46,904	(20,504)
Investing activities			
Investment in subsidiaries	(275,070)	(274,406)	(30,722)
Other property	—	—	2
Net cash used in investing activities	(275,070)	(274,406)	(30,720)
Financing activities			
Net proceeds from the initial public offering	—	580,374	—
Purchase of treasury stock	(8,378)	—	—
Deferred financing costs	(7,530)	—	—
Net cash provided by financing activities	(15,908)	580,374	—
Net increase (decrease) in cash and cash equivalents	(220,298)	352,872	(51,224)
Cash and cash equivalents at beginning of period	352,872	—	51,224
Cash and cash equivalents at end of period	$ 132,574	$ 352,872	$ —

Schedule II

Kosmos Energy Ltd.

Valuation and Qualifying Accounts

For the Years Ended December 31, 2012, 2011 and 2010

Description	Balance January 1,	Additions: Charged to Costs and Expenses	Additions: Charged To Other Accounts	Deductions From Reserves	Balance December 31,
2012					
Allowance for doubtful receivables	$ —	$ —	$ —	$ —	$ —
Allowance for deferred tax asset	$49,502	$ 14,103	$ —	$ —	$63,605
2011					
Allowance for doubtful receivables	$39,782	$(39,782)	$ —	$ —	$ —
Allowance for deferred tax asset	$30,140	$ 19,362	$ —	$ —	$49,502
2010					
Allowance for doubtful receivables	$ —	$ 39,782	$ —	$ —	$39,782
Allowance for deferred tax asset	$33,749	$ (3,609)	$ —	$ —	$30,140

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

(3) Exhibits

See "Index to Exhibits" on page 145 for a description of the exhibits filed as part of this report.

SIGNATURES

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

KOSMOS ENERGY LTD.

Date: February 25, 2013

By: /s/ W. GREG DUNLEVY

W. Greg Dunlevy
Chief Financial Officer and Executive Vice President

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

Signature	Title	Date
/s/ BRIAN F. MAXTED Brian F. Maxted	Director and Chief Executive Officer (Principal Executive Officer)	February 25, 2013
/s/ W. GREG DUNLEVY W. Greg Dunlevy	Chief Financial Officer and Executive Vice President (Principal Financial Officer)	February 25, 2013
/s/ PAUL M. NOBEL Paul M. Nobel	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 25, 2013
/s/ JOHN R. KEMP John R. Kemp	Chairman of the Board of Directors	February 25, 2013
/s/ SIR RICHARD B. DEARLOVE Sir Richard B. Dearlove	Director	February 25, 2013
/s/ DAVID I. FOLEY David I. Foley	Director	February 25, 2013
/s/ DAVID B. KRIEGER David B. Krieger	Director	February 25, 2013

Signature	Title	Date
/s/ JOSEPH P. LANDY Joseph P. Landy	Director	February 25, 2013
/s/ PRAKASH A. MELWANI Prakash A. Melwani	Director	February 25, 2013
/s/ ADEBAYO O. OGUNLESI Adebayo O. Ogunlesi	Director	February 25, 2013
/s/ LARS H. THUNELL Lars H. Thunell	Director	February 25, 2013
/s/ CHRIS TONG Chris Tong	Director	February 25, 2013
/s/ CHRISTOPHER A. WRIGHT Christopher A. Wright	Director	February 25, 2013

INDEX OF EXHIBITS

Exhibit Number	Description of Document
3.1	Certificate of Incorporation of the Company (filed as Exhibit 3.1 to the Company's Registration Statement on Form S-1/A filed March 23, 2011 (File No. 333-171700), and incorporated herein by reference).
3.2	Memorandum of Association of the Company (filed as Exhibit 3.2 to the Company's Registration Statement on Form S-1/A filed March 23, 2011 (File No. 333-171700), and incorporated herein by reference).
3.3	Bye-laws of the Company (filed as Exhibit 4 to the Company's Registration Statement on Form 8-A filed May 6, 2011 (File No. 001-35167), and incorporated herein by reference).
4.1	Specimen share certificate (filed as Exhibit 4.1 to the Company's Registration Statement on Form S-1/A filed April 25, 2011 (File No. 333-171700), and incorporated herein by reference).
9.1*	Shareholders Agreement, dated as of May 10, 2011, among Kosmos Energy Ltd. and the other parties signatory thereto.
10.1	Petroleum Agreement in respect of West Cape Three Points Block Offshore Ghana dated July 22, 2004 among the GNPC, Kosmos Ghana and the E.O. Group (filed as Exhibit 10.1 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.2	Operating Agreement in respect of West Cape Three Points Block Offshore Ghana dated July 27, 2004 between Kosmos Ghana and E.O. Group (filed as Exhibit 10.2 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.3	Petroleum Agreement in respect of the Deepwater Tano Contract Area dated March 10, 2006 among GNPC, Tullow Ghana, Sabre and Kosmos Ghana (filed as Exhibit 10.3 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.4	Joint Operating Agreement in respect of the Deepwater Tano Contract Area, Offshore Ghana dated August 14, 2006, among Tullow Ghana, Sabre Oil and Gas Limited, and Kosmos Ghana (filed as Exhibit 10.4 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.5	Assignment Agreement in respect of the Deepwater Tano Block dated September 1, 2006, among Anadarko WCTP and Kosmos Ghana (filed as Exhibit 10.5 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.6	Unitization and Unit Operating Agreement covering the Jubilee Field Unit located offshore the Republic of Ghana dated July 13, 2009, among GNPC, Tullow, Kosmos Ghana, Anadarko WCTP, Sabre and E.O. Group (filed as Exhibit 10.6 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).

Exhibit Number	Description of Document
10.7	Ndian River Production Sharing Contract dated November 20, 2006 between the Republic of Cameroon and Kosmos Cameroon (filed as Exhibit 10.8 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.8	Petroleum Agreement regarding the exploration for and exploitation of hydrocarbons in the area of interest named Boujdour Offshore dated May 3, 2006 between ONHYM and Kosmos Morocco (filed as Exhibit 10.14 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.9	Association Contract regarding the exploration for and exploitation of hydrocarbons in the Boujdour Offshore Block dated May 3, 2006 between ONHYM and Kosmos Morocco (filed as Exhibit 10.15 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.10	Memorandum of Understanding regarding a new petroleum agreement covering certain areas of the Boujdour Offshore Block dated September 27, 2010 between ONHYM and Kosmos Morocco (filed as Exhibit 10.16 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.11	Facility Agreement, dated March 28, 2011 among Kosmos Finance International, Kosmos Operating, Kosmos International, Kosmos Development and Kosmos Ghana and the various financial institutions and others party thereto (filed as Exhibit 10.17 to the Company's Registration Statement on Form S-1/A filed April 25, 2011 (File No. 333-171700), and incorporated herein by reference).
10.12	Intercreditor Agreement, dated March 28, 2011 among BNP Paribas, Kosmos Finance International, Kosmos Operating, Kosmos International, Kosmos Development, Kosmos Ghana and the various financial institutions and others party thereto (filed as Exhibit 10.20 to the Company's Registration Statement on Form S-1/A filed April 25, 2011 (File No. 333-171700), and incorporated herein by reference).
10.13†	Form of Long Term Incentive Plan (filed as Exhibit 10.21 to the Company's Registration Statement on Form S-1/A filed March 30, 2011 (File No. 333-171700), and incorporated herein by reference).
10.14†	Form of Annual Incentive Plan (filed as Exhibit 10.22 to the Company's Registration Statement on Form S-1/A filed March 30, 2011 (File No. 333-171700), and incorporated herein by reference).
10.15†	Form of Non-Qualified Stock Option Award Agreement (filed as Exhibit 10.23 to the Company's Registration Statement on Form S-1/A filed March 30, 2011 (File No. 333-171700), and incorporated herein by reference).
10.16†	Form of Restricted Stock Award Agreement (Exchange) (filed as Exhibit 10.24 to the Company's Registration Statement on Form S-1/A filed March 30, 2011 (File No. 333-171700), and incorporated herein by reference).
10.17†	Form of Restricted Stock Award Agreement (Service Vesting) (filed as Exhibit 10.25 to the Company's Registration Statement on Form S-1/A filed March 30, 2011 (File No. 333-171700), and incorporated herein by reference).

Exhibit Number	Description of Document
10.18†	Form of Restricted Stock Award Agreement (Performance Vesting) (filed as Exhibit 10.26 to the Company's Registration Statement on Form S-1/A filed March 30, 2011 (File No. 333-171700), and incorporated herein by reference).
10.19†	Form of RSU Award Agreement (Directors—Service Vesting) (field as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012, and incorporated herein by reference)
10.20†	Form of RSU Award Agreement (Employees—Service Vesting) (field as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012, and incorporated herein by reference)
10.21†	Form of RSU Award Agreement (Employees—Performance Vesting) (field as Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012, and incorporated herein by reference)
10.22	Form of Director Indemnification Agreement (filed as Exhibit 10.27 to the Company's Registration Statement on Form S-1/A filed April 14, 2011 (File No. 333-171700), and incorporated herein by reference).
10.23	Settlement Agreement, dated December 18, 2010 among Kosmos Ghana, Ghana National Petroleum Corporation and the Government of the Republic of Ghana (filed as Exhibit 10.32 to the Company's Registration Statement on Form S-1/A filed April 14, 2011 (File No. 333-171700), and incorporated herein by reference).
10.24†	Consulting Agreement dated October 31, 2011 between Kosmos Energy Ltd. and John R. Kemp (filed as Exhibit 10.33 to the Company's Annual Report on Form 10-K for the year ended December 31, 2011, and incorporated herein by reference).
10.25†	Amendment No. 1 to Consulting Agreement dated Feruary 23, 2012 between Kosmos Energy Ltd. and John R. Kemp (filed as Exhibit 10.33 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2012, and incorporated herein by reference).
10.26	Deed of Transfer and Amendment, dated February 17, 2012, among Kosmos Energy Finance International, Kosmos Energy Operating, Kosmos Energy International, Kosmos Energy Development, Kosmos Energy Ghana HC, BNP Paribas, Citibank N.A., Credit Suisse International, Société Générale London Branch and International Finance Corporation (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2012, and incorporated herein by reference).
10.27	Facility Agreement, dated February 17, 2012, among Kosmos Energy Finance International, Kosmos Energy Operating, Kosmos Energy International, Kosmos Energy Development, Kosmos Energy Ghana HC and International Finance Corporation (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2012, and incorporated herein by reference).
10.28*	Revolving Credit Facility Agreement, dated as of November 23, 2012, among Kosmos Energy Ltd., as Original Borrower, certain of its subsidiaries listed therein, as Original Guarantors, HSBC Bank plc, Société Générale, London Branch, Standard Chartered Bank, BNP Paribas, The Standard Bank of South Africa Limited and Banc of America Securities Limited, as Mandated Lead Arrangers, Standard Chartered Bank, as Facility Agent, BNP Paribas, as Security and Intercreditor Agent, and the financial institutions listed therein, as Original Lenders.

Exhibit Number	Description of Document
10.29*	Deed of Guarantee and Indemnity, dated as of November 23, 2012, among Kosmos Energy Ltd., and Kosmos Energy Operating, Kosmos Energy International, Kosmos Energy Development, Kosmos Energy Ghana HC and Kosmos Energy Finance International, as Original Guarantors, and BNP Paribas, as Security and Intercreditor Agent.
10.30*	Deed of Amendment and Restatement relating to the Facility Agreement and a Charge over Shares in Kosmos Energy Operating, dated November 23, 2012, among Kosmos Energy Finance International, as Original Borrower, Kosmos Energy Operating, Kosmos Energy International, Kosmos Energy Development and Kosmos Energy Ghana HC, as Original Guarantors, Kosmos Energy Holdings, as Chargor, and BNP Paribas, as Facility Agent and Security Agent.
10.31*	Intercreditor Agreement, dated as of November 23, 2012, among Kosmos Energy Ltd., as HY Note Issuer and RCF Borrower, Kosmos Energy Finance International, as Original Senior Borrower, BNP Paribas, as Security Agent, Security and Intercreditor Agent and Proceeds Agent, and Standard Chartered Bank, as RCF Agent.
10.32*	Registration Rights Agreement, dated as of October 7, 2009, among Kosmos Energy Holdings and the other parties signatory thereto.
10.33*	Joinder Agreement to the Registration Rights Agreement, dated as of May 10, 2011, among Kosmos Energy Ltd. and the other parties signatory thereto.
10.34*	Amendment No. 1 to the Registration Rights Agreement, dated as of February 8, 2013, among Kosmos Energy Ltd. and the other parties signatory thereto.
10.35	Underwriting Agreement dated February 14, 2013 among the Company, the Underwriters named therein and certain Selling Shareholders named therein (filed as Exhibit 1.1 to the Company's Current Report on Form 8-K filed February 21, 2013 (File No. 001-35167), and incorporated herein by reference).
14.1	Code of Business Conduct and Ethics (filed as Exhibit 14.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2011, and incorporated herein by reference).
21.1*	List of Subsidiaries.
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Report of Netherland, Sewell & Associates, Inc.
101.INS*	XBRL Instance Document.

Exhibit Number	Description of Document
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.

* Filed herewith.

** Furnished herewith.

† Management contract or compensatory plan or arrangement.

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