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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2013

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

For the transition period from to

Commission file number: 001-35167

Kosmos Energy Ltd.
(Exact name of registrant as specified in its charter)

Bermuda	**98-0686001**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

Clarendon House **2 Church Street** **Hamilton, Bermuda** (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 $951,286,205.

The number of the registrant's Common Shares outstanding as of February 18, 2014 was 387,595,931.

DOCUMENTS INCORPORATED BY REFERENCE

Part III, Items 10-14, is incorporated by reference from the Proxy Statement for the Annual Meeting of Shareholders which will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 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.

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.
"Farm-out"	An agreement whereby the owner of the participating interest agrees to assign a portion of its participating interest in a block to another party for cash or for the assignee taking on a portion of the drilling costs of one or more specific wells and/or other work as a condition of the assignment.
"Field life cover ratio"	The "field life cover ratio" is broadly defined, for each applicable forecast period, as the ratio of (x) 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.
"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 hydrocarbons gives an E&P company temporary and limited rights, including an exclusive option to explore for, develop, and produce hydrocarbons from the lease area.
"Petroleum system"	A petroleum system consists of organic material that has been buried at a sufficient depth to allow adequate temperature and pressure to expel hydrocarbons and cause the movement of oil and natural gas from the area in which it was formed to a reservoir rock where it can accumulate.
"Plan of development" or "PoD"	A written document outlining the steps to be undertaken to develop a field.
"Productive well"	An exploratory or development well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.
"Prospect(s)"	A potential trap that may contain hydrocarbons and is supported by the necessary amount and quality of geologic and geophysical data to indicate a probability of oil and/or natural gas accumulation ready to be drilled. The five required elements (generation, migration, reservoir, seal and trap) must be present for a prospect to work and if any of 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 hydrocarbons 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 hydrocarbons 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, Ireland, Mauritania, Morocco (including Western Sahara) 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 and production 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 along the Atlantic Margin. Our assets include existing production and other major development projects offshore Ghana, as well as exploration licenses with significant hydrocarbon potential offshore Ireland, Mauritania, Morocco (including Western Sahara) and Suriname. 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; developing the Tweneboa-Enyenra-Ntomme ("TEN") project which was approved by the Ministry of Energy in 2013; appraising our other discoveries in Ghana; and beginning a multi-year, exploration drilling program targeting several high impact opportunities.

Our Business Strategy

Grow proved reserves and production through exploration, appraisal and development

We plan to optimize production and further develop the Jubilee Field, bring the TEN development project to production and appraise the Mahogany, Teak, Akasa and Wawa discoveries. In May 2013, the government of Ghana approved the PoD over the TEN discoveries. The TEN project is expected to deliver first oil in 2016. In the event of a declaration of commerciality and approval of a plan of development over our Mahogany, Teak, Akasa and/or Wawa discoveries, we intend to develop these discoveries to grow proved reserves and production. We also plan to drill exploration prospects, with the intent to further grow proved reserves and production should discoveries be made.

Successfully open and develop our offshore exploration plays

We believe the prospects and leads potentially existing offshore Morocco, Mauritania, Suriname and Ireland provide a favorable opportunity to meaningfully create value. We anticipate drilling two to three play-opening exploratory wells per year in these basins beginning in 2014, depending on our analysis of seismic data covering the blocks, initial exploration drilling results and availability of drilling rigs and other required equipment and services. Depending on the results of these exploratory wells, additional wells may be drilled. Given the potential size of these prospects and leads, we believe that exploratory success in our operating areas could be significantly accretive to shareholder value.

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 development personnel are critical to the success of our business strategy. We have created an environment that enables them to focus their knowledge, skills and experience on finding and developing oil fields. Culturally, we have an open, team-oriented work environment that fosters both creative and contrarian thinking. This approach enables us to fully consider and understand both risk and reward, as well as deliberately and collectively pursue strategies that maximize value. 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 field developments designed to deliver early learnings and accelerate 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 use our systematic and proven geologically-focused approach to frontier and emerging petroleum systems where geological data suggests hydrocarbon accumulations are likely to exist, but where commercial discoveries have yet to be made. We believe this approach reduces the exploratory risk in poorly understood, under-explored or otherwise overlooked hydrocarbon basins that offer significant 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 Cretaceous petroleum systems across the Atlantic Margin, including play types that had previously been largely ignored. In addition, our exploration portfolio includes sub-salt plays, which has been the other recent successful play concept along the Atlantic Margin.

This approach and focus, coupled with a first mover advantage and our management and technical teams' reputation and relationships, provide a competitive advantage in identifying and accessing new strategic growth opportunities. We expect to continue seeking 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 our reach into other locations along the Atlantic Margin. 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 targets licenses over the particular basin or fairway to achieve an early mover or in many cases a first-mover advantage. In terms of license selection, Kosmos targets specific regions that have sufficient size to provide scale should the exploration concept prove successful. Kosmos also looks for long-term contract duration to enable the "right" exploration program to be executed, play type diversity to provide multiple exploration concept options, prospect dependency to enhance the chance of replicating success and sufficiently attractive fiscal terms to maximize the commercial viability of discovered hydrocarbons.

Operations by Geographic Area

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

Ghana

The West Cape Three Points Block ("WCTP Block") and Deepwater Tano Block ("DT Block") are located within the Tano Basin, offshore Ghana. This basin contains a proven world-class petroleum system as evidenced by our discoveries.

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

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

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

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(11)
Ghana						
Jubilee Field Phase 1 and Phase 1A(1)(2)	WCTP/DT(3)	24.0771%(5)	Tullow/Kosmos(7)	Production	Deepwater	2008/2011(2)
Jubilee Field subsequent phases(1)	WCTP/DT(3)	24.0771%(5)	Tullow/Kosmos(7)	Development	Deepwater	2014(8)
Mahogany	WCTP	30.8750%(4)	Kosmos	Appraisal	Deepwater	2015(9)
Teak	WCTP	30.8750%(4)	Kosmos	Appraisal	Deepwater	2015(9)
Akasa	WCTP	30.8750%(4)	Kosmos	Appraisal	Deepwater	2015(9)
TEN	DT	17.0000%(6)	Tullow	Development	Deepwater	2012(10)
Wawa	DT	18.0000%(4)	Tullow	Appraisal	Deepwater	2015

(1) For information concerning our estimated proved reserves in the Jubilee Field as of December 31, 2013, see "—Our Reserves."

(2) The Jubilee Phase 1 and Phase 1A PoDs were approved by Ghana's Ministry of Energy in 2009 and 2012, respectively. The Jubilee Phase 1 and Phase 1A PoDs detail the necessary wells and infrastructure to develop three 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.

(3) The Jubilee Field straddles the boundary between the WCTP Block and the DT Block offshore Ghana. Consistent with the Ghanaian Petroleum Law, the WCTP Petroleum Agreement ("WCTP PA") and DT Petroleum Agreement ("DT PA") and as required by Ghana's Ministry of Energy, in order to optimize resource recovery in this field, we entered into the Unitization and Unit Operating Agreement (the "UUOA") in July 2009 with Ghana National Petroleum Corporation ("GNPC") and the other block partners of each of these two blocks. The UUOA governs the interests in and development of the Jubilee Field and created the Jubilee Unit from portions of the WCTP 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) In February 2013, GNPC exercised its DT PA option, with respect to TEN, to acquire an additional paying interest of 5.0%. The TEN interest percentage gives effect to the exercise of such option. Our paying interest on development activities in TEN is 19%.

(7) 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."

(8) We submitted the Jubilee Full Field Development Plan ("JFFDP") to Ghana's Minister of Energy in December 2012 and subsequently withdrew based on discussions with the government of Ghana. A PoD providing for development of the next phase within the Jubilee Field is expected to be submitted during 2014, although we can give no assurance that such approvals will be forthcoming in a timely manner or at all.

(9) Effective January 14, 2014, the Ministry of Energy and GNPC entered into a Memorandum of Understanding with Kosmos Energy, on behalf of the WCTP PA Block partners, wherein all parties have settled all matters pertaining to the Notices of Dispute for the Mahogany East PoD and the Cedrela Notice of Force Majeure, and the Ministry of Energy has approved the Appraisal Programs for the Mahogany, Teak, and Akasa discoveries. As a result of the settlement, a portion of the WCTP PA area which contained the Cedrela prospect has been relinquished.

(10) The DT Block partners submitted a declaration of commerciality and a PoD to Ghana's Ministry of Energy in November 2012. In May 2013, the government of Ghana approved the PoD over the TEN discoveries. Development of TEN will include the drilling and completion of up to 24 development wells; half of the wells are designed as producers and the remainder as water or gas injectors to support ultimate field recoveries. The TEN project is expected to deliver first oil in 2016.

(11) 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 8Financial Statements and Supplementary Data—Note 4—Joint Interest Billings") to 24.07710%. See "Item 1A. Risk Factors—The unit partners' respective interests 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. 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 and asset value.

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 through stimulation treatments. We received approval for the Phase 1A PoD of the Jubilee Field and production from Phase 1A development commenced in late 2012. The Phase 1A development includes the drilling of up to eight additional wells consisting of up to five production wells and three water injection wells. Five wells (three producers and two water injection wells) are online. Program execution is expected to be completed in 2014.

The Government of Ghana is in the process of completing the construction and connection of a gas pipeline from the Jubilee Field to transport natural gas to the mainland for processing and sale; however, to date, the construction of the pipeline and the onshore plant has not been completed and the Company is presently unable to predict with certainty when completion will occur, as several previous completion dates have passed. In the absence of a pipeline to remove large quantities of natural gas from the Jubilee Field in order to maximize production levels it is anticipated that we will need to flare such natural gas. Currently, we have not been issued an amended permit from the Ghana Environmental Protection Agency ("Ghana EPA") to flare natural gas produced from the Jubilee Field in substantial quantities. If we are unable to resolve issues related to the continuous removal of associated natural gas in large quantities from the Jubilee Field, our oil production will be negatively impacted. See "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."

During 2013, we experienced mechanical issues in the Jubilee Field, including failures of our water injection facilities on the FPSO and water and gas injection wells. This equipment downtime negatively impacted oil production during the year.

Oil production from the Jubilee Field averaged approximately 97,500 barrels of oil per day during 2013. We submitted the JFFDP to Ghana's Minister of Energy in December 2012 and subsequently withdrew based on discussions with the government of Ghana. A PoD providing for development of the next phase within the Jubilee Field is expected to be submitted during 2014, although we can give no assurance that such approvals will be forthcoming in a timely manner or at all.

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.

Effective January 14, 2014, the Ministry of Energy and GNPC entered into a Memorandum of Understanding with Kosmos Energy, on behalf of the WCTP PA Block partners, wherein all parties have settled all matters pertaining to the Notices of Dispute for the Mahogany East PoD and the Cedrela Notice of Force Majeure, and the Ministry of Energy has approved the Appraisal Programs for the Mahogany, Teak, and Akasa discoveries. As a result of the settlement, a portion of the WCTP PA area which contained the Cedrela prospect has been relinquished.

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. We believe that the Akasa-2A appraisal well successfully identified the down dip water contact associated with the Akasa-1 discovery as intended. Should the Akasa discovery progress to a development, the Akasa-2A appraisal well is expected to be utilized in the development as a water injection well. However, since the Akasa-2A appraisal well did not encounter oil or gas reserves sufficient to be utilized as a producing well, accounting rules require that the costs associated with the Akasa-2A appraisal well be impaired. 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.

Kosmos is the operator of the WCTP Block and holds a 30.875% participating interest. The 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 relinquished ("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. Effective January 14, 2014, the Ministry of Energy and GNPC entered into a Memorandum of Understanding with Kosmos Energy, on behalf of the WCTP PA Block partners, wherein all parties have settled all matters pertaining to the Notices of Dispute for the Mahogany East PoD and the Cedrela Notice of Force Majeure, and the Ministry of Energy has approved the Appraisal Programs for the Mahogany, Teak, and Akasa discoveries. As a result of the settlement, a portion of the WCTP PA area which contained the Cedrela prospect has been relinquished.

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, Enyenra-4A and Enyenra-6A wells have intersected multiple oil and natural gas condensate bearing reservoirs in a Turonian turbidite sequence. Fluid samples recovered from the wells indicate an approximate oil gravity of 32 degrees API, and a natural gas condensate gravity of between 42 and 48 degrees API. We believe Enyenra is predominantly an oil accumulation.

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

In November 2012, we submitted a declaration of commerciality and PoD over the TEN discoveries (includes Tweneboa, Enyenra and Ntomme). In May 2013, the government of Ghana approved the PoD over the TEN discoveries. Development of TEN will include the drilling and completion of up to 24 development wells, half of the wells designed as producers and the remainder as water or gas injectors to support ultimate field recoveries. The TEN development is expected to deliver first oil in 2016. Future development of gas resources at TEN is anticipated following the commencement of oil startup.

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.

Kosmos holds a non-operated 18.0% participating interest in the DT Block. The DT PA, which governs our activities relating to the DT Block and for commercial development areas therein, 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 determined.

Ireland

We have identified the Porcupine Basin Offshore Ireland as an underexplored basin with the potential for large oil hydrocarbon accumulations in our core Cretaceous stratigraphic play concept.

The Porcupine Basin is a Jurassic aged rift basin located on the eastern Atlantic margin offshore Southwest Ireland. Previous exploration was focused on Jurassic and Tertiary aged sandstones located in the shallow water portions of the basin. These wells encountered Jurassic, Cretaceous and Tertiary reservoirs, Jurassic source rocks and oil and gas; however, no commercial developments have taken place in the basin. We have identified a number of geologic features of Cretaceous age on vintage 2D seismic data which have play potential similar to the features identified in our Atlantic Margin acreage.

In April 2013, we entered into a farm-in agreement with Antrim Energy Inc. ("Antrim"), whereby we acquired a 75% participating interest and operatorship, covering Licensing Option 11/5 offshore the west coast of Ireland. As part of the agreement, we reimbursed a portion of previously-incurred exploration costs and are paying the partner's share of 3D seismic costs.

In April 2013, we entered into a farm-in agreement with Europa Oil & Gas (Holdings) plc ("Europa"), whereby we acquired an 85% participating interest and operatorship, covering Licensing Option 11/7 and 11/8 offshore the west coast of Ireland. As part of the agreement, we reimbursed a portion of previously-incurred exploration costs and are paying the partner's share of 3D seismic costs. Contingent upon an election by us and our partner to enter into a subsequent exploration drilling phase on one or both of the blocks, we will also fund 100% of the costs of the first exploration well on each block, subject to an investment cap of $90.0 million and $110.0 million, respectively, on each block.

In July 2013, Ireland granted us Frontier Exploration Licenses 1-13, 2-13, and 3-13 pursuant to Licensing Options 11/5, 11/7 and 11/8. The term of each contract is 15 years unless surrendered or revoked, and is divided into an initial phase of three years, and three subsequent phases of four years each. Relinquishment of 25% of the existing area is required at the end of the first phase and 50% of the existing area at the end of the second phase. Three months before the end of each phase, we must propose a work program for the subsequent phase for the approval of the Minister of Communications, Energy and Natural Resources. The second phase work program must include an exploration well. The contract area must be surrendered if a second exploration well has not been commenced by the end of the third phase. Upon entering these Frontier Exploration Licenses, we and the other block partners relinquished approximately 25% of the acreage covered by the Licensing Options.

We completed a 3D seismic data acquisition program of approximately 5,000 square kilometers over these blocks and in the surrounding area in October 2013. The processing of this seismic data is expected to be completed in 2014.

We are currently assessing prospectivity on license areas in Ireland, and accordingly information concerning prospects, if any, on such recently acquired license areas is not yet available. We currently are, and plan to continue, processing seismic information to assess the prospectivity for these license areas.

Mauritania

In June 2012, we successfully acquired three new petroleum contracts offshore Mauritania. The new petroleum contracts are Offshore Blocks C8, C12 and C13. We are the operator and hold 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. We are 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 Mauritania Salt Basin. The blocks are adjacent to a proven petroleum system with the primary targets being Cretaceous sediments in structural and stratigraphic traps. Available geologic and geophysical data has led to the interpretation and mapping of possible Cretaceous basin floor fans in possible trapping geometries outboard of the Salt Basin. The Cretaceous source rocks penetrated by wells and typed to oils in the Mauritania Salt Basin are believed to be the same age as those which charge other oil and gas fields in the Late Cretaceous of West Africa.

Mauritania is located in Northwest Africa and its continental shelf is part of the Mauritania-Senegal-Guinea Bissau (MSGBC) Atlantic margin basin. This is a Triassic salt basin which formed at the onset of rifting and contains an overlying Jurassic, Cretaceous and Tertiary passive margin sequence of limestones, sandstone and shales.

A number of exploration wells have been drilled in shallow to moderate water depths in the basin and have resulted in oil and gas discoveries in both Tertiary and Cretaceous aged features. One of these, the Chinguetti Field is currently producing.

Our acreage is located outboard of the producing area in three licenses which vary in water depth from 1,500 to 3,000 meters. These blocks cover an aggregate area of approximately 6.6 million acres and are focused beyond the edge of the salt province on the basin floor where potentially reservoir bearing Mid to Late Cretaceous aged stratigraphy has been identified on vintage 2D seismic data in areas where there is evidence for trapping geometries. Our understanding of the blocks will be refined with additional seismic data acquisition over the areas where a number of leads with considerable petroleum potential have been identified.

In May 2013, we completed a 2D seismic data acquisition program on approximately 6,000 line-kilometers, covering Blocks C8, C12 and C13. In November 2013, we completed a 3D seismic program of approximately 10,300 square kilometers over portions of Blocks C8 and C12. Processing of this seismic data is expected to be completed in 2014.

We are currently assessing prospectivity on license areas in Mauritania, and accordingly information concerning prospects, if any, on such recently acquired license areas is not yet available. We currently are, and plan to continue, processing seismic information to assess the prospectivity for these license areas.

Morocco (including Western Sahara)

During 2011, we acquired two new petroleum contracts, renewed an existing petroleum contract and acquired a new reconnaissance contract (which was subsequently converted to a new petroleum contract) in Morocco. Our petroleum contracts include the Cap Boujdour Offshore block, which is within the Aaiun Basin, and the Essaouira Offshore block, the Foum Assaka Offshore block and the Tarhazoute Offshore block, which are within the Agadir Basin. We are the operator of these petroleum contracts and our initial participating interests were 75%, 37.5%, 37.5% and 75% for the Cap Boujdour Offshore block, the Essaouira Offshore block, the Foum Assaka Offshore block and the Tarhazoute Offshore block, respectively.

Aaiun Basin

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

We are the operator of the Cap Boujdour Offshore block. 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 and/or gas for a period of 25 years from the grant of an exploitation authorization from the government, which may be extended for an additional period of 10 years under certain circumstances.

In October 2013, we entered into a farm-out agreement with Capricorn Exploration & Development Company Limited, a wholly owned subsidiary of Cairn Energy PLC ("Cairn"), covering the Cap Boujdour Offshore block, offshore Western Sahara. Under the terms of the agreement, Cairn will acquire a 20% non-operated interest in the exploration permits comprising the Cap Boujdour Offshore block. Cairn will pay 150% of its share of costs of a 3D seismic survey capped at $25.0 million and one exploration well capped at $100.0 million. In the event the exploration well is successful, Cairn will pay 200% of its share of costs on two appraisal wells capped at $100.0 million per well. Additionally, Cairn will contribute $12.3 million towards our future costs and, upon close of the transaction, $0.6 million for their share of costs incurred from the effective date of the contract through December 31, 2013. Completion of the transaction is subject to customary closing conditions, including Moroccan Government approvals. After completing the transaction, our participating interest in the Cap Boujdour Offshore block will be 55.0% and we will remain the operator.

Agadir Basin

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

In January 2013, we closed on an agreement to acquire an additional 37.5% participating interest in the Essaouira Offshore block from Canamens Energy Morocco SARL, one of our block partners. Governmental approvals and processes for this acquisition were finalized in November 2013.

In August 2013, final government approvals and processes were completed for the acquisition of an additional 18.75% participating interest in the Foum Assaka block in the Agadir Basin offshore Morocco from Pathfinder Hydrocarbon Ventures Limited ("Pathfinder"), a wholly owned subsidiary of Fastnet Oil and Gas plc ("Fastnet"), one of our block partners.

In October 2013, we entered into three farm-out agreements with BP plc ("BP") covering our three blocks in the Agadir Basin, offshore Morocco. Under the terms of the agreements, BP will acquire a non-operating interest in each of the Essaouira Offshore, Foum Assaka Offshore and Tarhazoute Offshore blocks. BP will fund Kosmos' share of the cost of one exploration well in each of the three blocks, subject to a maximum spend of $120.0 million per well, and pay its proportionate share of any well costs above the maximum spend. In the event a second exploration well is drilled in any block, BP will pay 150% of its share of costs subject to a maximum spend of $120.0 million per well. Upon close of the transaction, BP shall also pay $36.3 million for their share of past costs and $8.9 million for their portion of shared costs incurred from the effective date of the contract through December 31, 2013. Completion of the transactions is subject to customary closing conditions, including Moroccan Government approvals. After completing the transaction, our participating interests will be 30.0%, 29.925% and 30.0% in the Essaouira Offshore, Foum Assaka Offshore and Tarhazoute Offshore blocks, respectively, and we will remain the operator.

We have recently completed interpretation of approximately 7,800 square kilometers of new and reprocessed 3D seismic data in our Foum Assaka Offshore and Essaouira Offshore blocks. During 2014, we plan to begin a seismic data acquisition program over the Tarhazoute Offshore and Essaouira Offshore blocks. We have identified numerous prospects in the Foum Assaka Offshore and Essaouira Offshore blocks. We plan to drill the FA-1 exploration well on the Eagle prospect during 2014.

The Foum Assaka Offshore block is currently in the first extension period of the exploration permit, which is for two and one-half years from its effective date (January 1, 2014) ending in June 2016. 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 and/or gas for a period of 25 years from the grant of an exploitation authorization from the government, which may be extended for an additional period of 10 years under certain circumstances.

The Essaouira Offshore block is 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. Theexploration 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 and/or gas for a period of 25 years from the grant of an exploitation authorization from the government, which may be extended for an additional period of 10 years under certain circumstances.

In October 2013, Kosmos executed a petroleum agreement with the Office National des Hydrocarbures et des Mines ("ONHYM"), the national oil company of the Kingdom of Morocco, covering the Tarhazoute Offshore block, to which the Company previously held certain exploration rights under a 2011 reconnaissance contract. Under the terms of the petroleum contract, the Company is the operator of the Tarhazoute Offshore block. ONHYM holds a 25% carried interest in the block through the exploration period. The Tarhazoute Offshore block is currently in the first exploration period, which is for two and one-half years from its effective date (December 9, 2013) ending in June 2016. The exploration phase may be extended for a total duration of eight years at our election and subject to our fulfilling specific work obligations, which include acquisition of 3D seismic data during the first period and drilling an exploration well in each of the subsequent periods. In the event of commercial success, the Company has the right to develop and produce oil and/or gas for a period of 25 years from the grant of an exploitation concession from the Government of Morocco, which may be extended for an additional period of 10 years under certain circumstances.

We are currently assessing prospectivity on the Tarhazoute Offshore block 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, processing seismic information to assess the prospectivity for these license areas.

Suriname

Our blocks in Suriname are located within the Guyana-Suriname Basin, along the Atlantic transform 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. 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.

We believe the play types offshore Suriname are relatively similar to those offshore West Africa and may contain subtle stratigraphic traps similar to those discovered offshore Ghana in the 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 demonstrate 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 in the offshore basin. The source rocks are believed to be similar in age to those which charged some of the fields offshore West Africa. Suriname lies on the Atlantic transform margin of South America located between Guyana and French Guyana. The deep water basin is subdivided by the Demerara high, a platform area which separates the Suriname deep water basin from the French Guyana Basin where the recent Zaedyus oil discovery was made in Late Cretaceous sandstones in a stratigraphic trap. Block 42 and Block 45 sit in the deep water area west of the Demerara Platform in the center of a thick Cretaceous and Tertiary succession associated with the post rift subsidence of the Atlantic continental margin.

A number of onshore and shelf wells have encountered oil and, as previously noted, the Tamberedjo and Calcutta fields are currently producing. These fields are believed to be sourced from deep water Cretaceous source rocks. Seismic evidence suggests thick Late Cretaceous and Tertiary reservoir systems have been deposited in the deep water area and this stratigraphy may contain stratigraphic and structural trapping geometries analogous to both the Zaedyus and Jubilee discoveries.

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. In August 2013, we completed a 2D seismic program of approximately 1,400 line kilometers over a portion of Block 42, outside of the existing 3D seismic survey. The processing of these seismic data programs is expected to be completed by mid-2014.

The initial period for Block 42 offshore Suriname is for four years from its effective date (December 13, 2011). The Block 42 exploration phase may be extended to December 2020 at our election. We are currently in the first exploration period ending on December 12, 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 13, 2011). The Block 45 exploration phase may be extended to December 2018 at our election. We are currently in the first exploration period ending on December 12, 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.w

We have petroleum contracts covering Block 42 and Block 45 offshore Suriname. In November 2012, we finalized the assignment of a 50% participating interest in Block 42 and Block 45 to Chevron Global Energy Inc. ("Chevron") reducing our original interest from 100%. We retain a 50% participating interest in the blocks and remain the operator for the exploration phase of the petroleum contracts.

We are currently assessing prospectivity on 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, processing 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, 2013. 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, 2013, 2012 and 2011 were associated with our Jubilee Field in Ghana.

Summary of Oil and Gas Reserves

	2013 Net Proved Reserves(1)			2012 Net Proved Reserves(1)			2011 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	36	10	38	32	9	33	23	16	26
Proved undeveloped	9	1	9	10	1	10	25	8	26
Total	45	11	47	42	9	43	47	24	51

(1) Our unitized net interest is based on the 54.36660%/45.63340% 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 withi 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 ended December 31, 2013, include an increase of 11 MMBbl of proved reserves as a result of drilling and reservoir performance, which is partially offset by 8 MMBbl of production during 2013. During 2013, approximately 1 MMBbl of proved undeveloped reserves from December 31, 2012 converted to proved developed reserves as of December 31, 2013During the year ended December 31, 2013, we incurred $116.6 million of capital expenditures related to the Jubilee Field Phase 1A development.

Changes for the year ended 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 through the Phase 1A development of the Jubilee Field. These successful remediation efforts reduced the number of future drilling locations for the Jubilee Field (which included drilling locations related to our proved undeveloped reserves) and, as a result, approximately 5 MMBbl of proved undeveloped reserves from December 31, 2011 converted to proved developed reserves as of December 31, 2012. 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. As a result of progress on the Phase 1A development, approximately 10 MMBbl of proved undeveloped reserves from December 31, 2011 converted to proved developed reserves as of December 31, 2012. During the year ended December 31, 2012, we incurred $163.7 million of capital expenditures related to Phase 1A.

Changes for the year ended 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 3—Jubilee Field Unitization") and an increase in the estimated gas reserves to be used 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, 2013. All estimated future net revenues are attributable to projected production from the Jubilee Field in Ghana. If we are unable to resolve issues related to continuous removal of associated natural gas in large quantities from the Jubilee Field, and the production restraints caused thereby, then the field's future net revenues discussed herein will be adversely affected. 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."

	Projected Net Revenues (in millions except $/Bbl)
Future net revenues	$ 2,836
Present value of future net revenues:	
PV-10(1)	$ 2,237
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)	$ 2,237
Benchmark and differential oil price($/Bbl)(3)	$ 108.76

(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 2013 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 2013 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 $108.02/Bbl for Dated Brent at December 31, 2013. The price was adjusted for crude handling, transportation fees, quality, and a regional price differential. Based on the high quality of the crude, these adjustments are estimated to add a $0.74/Bbl premium relative to Dated Brent. This differential is utilized in our reserve estimates. The adjusted price utilized to derive the PV-10 is $108.76/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. 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, 2013 are based on costs in effect at December 31, 2013 and the 12-month unweighted arithmetic average of the first-day-of-the-month price for the fiscal year ended December 31, 2013, 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, 2013, 2012 and 2011, we engaged NSAI to prepare independent estimates of the extent and value of the proved reserves of certain of our oil and gas properties. These reports were prepared at our request to estimate our reserves and related future net revenues and PV-10 for the periods indicated therein. Our estimated reserves at December 31, 2013 and related future net revenues and PV-10 at December 31, 2013 are taken from reports prepared by NSAI, in accordance with petroleum engineering and evaluation principles which NSAI believes are commonly used in the industry and definitions and current regulations established by the SEC. The December 31, 2013 reserve report was completed on January 15, 2014, and a copy is included as an exhibit to this report.

In connection with the preparation of the December 31, 2013, 2012 and 2011 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, 2013, based upon its evaluation. NSAI's primary economic assumptions in estimates included an ability to sell oil at a price of $108.76/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 internal reserve and resource estimates. 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 provides oversight on the processes utilized in the development of our internal reserve and resource 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, 2013 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	6.5	—	—	27.1	6.5
West Cape Three Points(2)	—	—	113.1	35.0	113.1	35.0
Deepwater Tano	—	—	137.8	24.8	137.8	24.8
Ireland						
FEL 1/13	—	—	259.9	194.9	259.9	194.9
FEL 2/13	—	—	189.8	161.3	189.8	161.3
FEL 3/13	—	—	193.2	164.2	193.2	164.2
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	2,174.1	2,898.7	2,174.1
Foum Assaka	—	—	1,199.7	674.8	1,199.7	674.8
Tarhazoute(4)	—	—	1,915.9	1,436.9	1,915.9	1,436.9
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	6.5	23,666.3	17,728.8	23,693.4	17,735.1

(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 acreage within three discovery areas (Teak, Akasa and Mahogany) that were not subject to relinquishment on the expiry of the exploration phase.

(3) We have entered into farm-out agreements covering our four license areas in Morocco. The net acres shown do not reflect these farm-outs, as the agreements were not closed as of December 31, 2013. Once these farm-out agreements become effective, our estimated net acres in the Cap Boujdour, Essaouira, Foum Assaka and Tarhazoute license areas is 4,042.0 thousand acres, 869.6 thousand acres, 359.0 thousand acres and 574.8 thousand acres, respectively.

(4) In October 2013, Kosmos executed a petroleum agreement with the ONHYM, the national oil company of the Kingdom of Morocco, covering the Tarhazoute Offshore block, to which the Company previously held certain exploration rights under a 2011 reconnaissance contract. Under

the terms of the petroleum contract, the Company is the operator of the Tarhazoute Offshore block. ONHYM holds a 25% carried interest in the block through the exploration period. We are currently in the first exploration period, which is for two and one-half years from its effective date (December 9, 2013) ending in June 2016. The exploration phase may be extended for a total duration of eight years at our election and subject to our fulfilling specific work obligations, which include acquisition of 3D seismic data during the first period and drilling an exploration well in each of the subsequent periods. In the event of commercial success, the Company has the right to develop and produce oil and/or gas for a period of 25 years from the grant of an exploitation concession from the Government of Morocco, which may be extended for an additional period of 10 years under certain circumstances. The petroleum contract is subject to customary government approvals.

Drilling activity

The results of oil and natural gas wells drilled and completed for each of the last three years were as follows:

	Exploratory and Appraisal Wells(1)						Development Wells(1)							
	Productive(2)		Dry(3)		Total		Productive(2)		Dry(3)		Total		Total	Total
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Year Ended December 31, 2013														
Ghana														
Jubilee Unit	—	—	—	—	—	—	2	0.48	—	—	2	0.48	2	0.48
Deepwater Tano	—	—	1	0.18	1	0.18	—	—	—	—	—	—	1	0.18
Cameroon														
N'dian River	—	—	1	1.00	1	1.00	—	—	—	—	—	—	1	1.00
Total	—	—	2	1.18	2	1.18	2	0.48	—	—	2	0.48	4	1.66
Year Ended December 31, 2012														
Ghana														
Jubilee Unit	—	—	—	—	—	—	5	1.20	—	—	5	1.20	5	1.20
West Cape Three Points	—	—	1	0.31	1	0.31	—	—	—	—	—	—	1	0.31
Deepwater Tano	—	—	1	0.18	1	0.18	—	—	—	—	—	—	1	0.18
Total	—	—	2	0.49	2	0.49	5	1.20	—	—	5	1.20	7	1.69
Year Ended December 31, 2011														
Ghana														
Jubilee Unit	—	—	—	—	—	—	1	0.24	—	—	1	0.24	1	0.24
West Cape Three Points	—	—	4	1.24	4	1.24	—	—	—	—	—	—	4	1.24
Cameroon														
Kombe-N'sepe	—	—	1	0.35	1	0.35	—	—	—	—	—	—	1	0.35
Total	—	—	5	1.59	5	1.59	1	0.24	—	—	1	0.24	6	1.83

(1) As of December 31, 2013, 10 exploratory and appraisal wells have been excluded from the table until a determination is made if the wells have found proved reserves. Thirteen development wells awaiting completion have also been excluded. 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, 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	—	—	—	—	—	—	—	—
West Cape Three Points	—	—	—	—	9	2.78	—	—
TEN	—	—	1	0.17	—	—	13	2.21
Deepwater Tano	—	—	—	—	1	0.18	—	—
Total	—	—	1	0.17	10	2.96	13	2.21

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 theseven-year exploration phase, the WCTP Relinquishment Area was relinquished. 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. Effective January 14, 2014, the Ministry of Energy and GNPC entered into a Memorandum of Understanding with Kosmos Energy, on behalf of the the WCTP PA Block partners, wherein all parties have settled all matters pertaining to the Notices of Dispute for the Mahogany East PoD and the Cedrela Notice of Force Majeure, and the Ministry of Energy has approved the Appraisal Programs for the Mahogany, Teak, and Akasa discoveries. As a result of the settlement, a portion of the WCTP PA area which contained the Cedrela prospect has been relinquished. We and our WCTP Block partners have certain rights to negotiate a new petroleum contract with respect to the WCTP Relinquishment Area. We and our WCTP Block partners, the Ghana Ministry of 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.

The exploration phase of the DT PA expired in January 2013. Our existing Wawa discovery within the DT Block was 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. Evaluation and appraisal activities continue on the Wawa discovery. Additionally, the TEN development project was not subject to relinquishment. We and our DT Block partners exercised 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.

During 2013, we took all actions required to voluntarily relinquish all of the area under the Ndian River Block and Fako Block in Cameroon.

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.

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 relinquished. 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. Effective January 14, 2014, the Ministry of Energy and GNPC entered into a Memorandum of Understanding with Kosmos Energy, on behalf of the the WCTP PA Block partners, wherein all parties have settled all matters pertaining to the Notices of Dispute for the Mahogany East PoD and the Cedrela Notice of Force Majeure, and the Ministry of Energy has approved the Appraisal Programs for the Mahogany, Teak, and Akasa discoveries. As a result of the settlement, a portion of the WCTP PA area which contained the Cedrela prospect has been relinquished. We and our WCTP Block partners have certain rights to negotiate a new petroleum contract with respect to the WCTP Relinquishment Area. We and our WCTP Block partners, the Ghana Ministry of Energy and GNPC have agreed such WCTP PA rights to negotiate 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.

The exploration phase of the DT PA expired in January 2013 and all work and financial obligations for the exploration periods under the DT PA have been met. Our existing Wawa discovery within the DT Block was 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. Evaluation and appraisal activities continue on the Wawa discovery. Additionally, the TEN development project was not subject to relinquishment. We and our DT Block partners exercised 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.

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 4—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. We 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. Our 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. We submitted the JFFDP to Ghana's Minister of Energy in December 2012 and subsequently withdrew based on discussions with the government of Ghana. A PoD providing for the next development of reservoirs within the Jubilee Field is expected to be submitted during 2014, although we can give no assurance that such approvals will be forthcoming in a timely manner or at all.

Morocco Exploration Agreements

Effective September 1, 2011, we entered into the Cap Boujdour Offshore Petroleum Agreement as the operator. In October 2013, we entered into a farm-out agreement with Cairn, covering the Cap Boujdour Offshore block, offshore Western Sahara. Under the terms of the agreement, Cairn will acquire a 20% non-operated interest in the exploration permits comprising the Cap Boujdour Offshore block. Cairn will pay 150% of its share of costs of a 3D seismic survey capped at $25.0 million and one exploration well capped at $100.0 million. In the event the exploration well is successful, Cairn will pay 200% of its share of costs on two appraisal wells capped at $100.0 million per well. Additionally, Cairn will contribute $12.3 million towards our future costs and, upon completion of the transaction, $0.6 million for their share of costs incurred from the effective date of the contract through December 31, 2013. Completion of the transaction is subject to customary closing conditions, including Moroccan Government approvals. After completing the transaction, our participating interest in the Cap Boujdour Offshore block will be 55.0% and we will remain the operator. The Moroccan national oil company, ONHYM, has a carried 25% participating interest. We are required to pay a 10% royalty on oil produced in water depths of 200 meters or less (the first 300,000 tons produced are exempt from royalty) and 7% royalty on oil produced in water depths deeper than 200 meters (the first 500,000 tons produced are exempt from royalty). These royalties are to be paid in-kind or, at the election of the government of Morocco, in cash. A corporate tax rate of 30% is applied to profits at the license level following a 10-year tax holiday post first production, if any. The Cap Boujdour Offshore block comprises approximately 7.35 million acres (29,741 square kilometers) (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.") The exploration term of the Cap Boujdour Offshore Permits, beginning on September 5, 2011, is eight years and includes an initial exploration period of one year and six months, which was extended for one year to March 5, 2014, followed by the first extension period of two years and the second extension period of four years and six months. We recently gave notice to enter the first extension period to be effective March 5, 2014. By entering the first extension period we are obligated to drill one exploration well. In the event of commercial success, we have the right to develop and produce oil and/or gas for a period of 25 years from the grant of an exploitation authorization from the government, which may be extended for an additional period of 10 years under certain circumstances.

Effective July 1, 2011, we entered into the Foum Assaka Offshore Petroleum Agreement as operator. In August 2013, final government approvals and processes were completed for the acquisition of an additional 18.75% participating interest in the Foum Assaka block in the Agadir Basin offshore Morocco from Pathfinder, a wholly owned subsidiary of Fastnet, one of our block partners. Pathfinder has retained an 18.75% participating interest. The Moroccan national oil company, ONHYM, has a 25% carried participating interest and is carried by us and Pathfinder proportionately during the exploration phase. We are required to pay a 10% royalty on oil produced in water depths of 200 meters or less (the first 300,000 tons produced are exempt from royalty) and 7% royalty on oil produced in water depths deeper than 200 meters (the first 500,000 tons produced are exempt from royalty). These royalties are to be paid in-kind or, at the election of the government of Morocco, in cash. A corporate tax rate of 30% is applied to profits at the license level following a 10-year tax holiday post first production. The term of the Foum Assaka Offshore Permits, beginning on July 1, 2011, is eight years and includes an initial exploration period of two years and six months followed by the first extension period of two years and six months and the second extension period of three years. We recently entered the first extension period effective January 1, 2014. By entering the first extension period we are obligated to drill one exploration well. After the required relinquishment of acreage to enter the first extension period, the Foum Assaka Offshore block comprises approximately 1.2 million acres (4,855 square kilometers). In the event of commercial success, we have the right to develop and produce oil and/or gas for a period of 25 years from the grant of an exploitation authorization from the government, which may be extended for an additional period of 10 years under certain circumstances.

Effective April 2, 2012, we entered into the Essaouria Offshore Petroleum Agreement as operator. In January 2013, we closed on an agreement to acquire an additional 37.5% participating interest in the Essaouira Offshore block from Canamens Energy Morocco SARL, one of our block partners. Governmental approvals and processes for this acquisition were finalized in November 2013 and our participating interest in the Essaouira Offshore block is 75%. The Moroccan national oil company, ONHYM, has a 25% carried participating interest and is carried by the block partners proportionately during the exploration phase. We are required to pay a 10% royalty on oil produced in water depths of 200 meters or less (the first 300,000 tons produced are exempt from royalty) and 7% royalty on oil produced in water depths deeper than 200 meters (the first 500,000 tons produced are exempt from royalty). These royalties are to be paid in-kind or, at the election of the government of Morocco, in cash. A corporate tax rate of 30% is applied to profits at the license level following a 10-year tax holiday post first production. The Essaouria Offshore Block comprises approximately 2.9 million acres (11,731 square kilometers). The term of the Essaouria Offshore Permits, beginning November 8, 2011, is eight years and includes an initial exploration period of two years and six months followed by the first extension period of three years and the second extension period of two years and six months. In the event of commercial success, we have the right to develop and produce oil and/or gas for a period of 25 years from the grant of an exploitation authorization from the government, which may be extended for an additional period of 10 years under certain circumstances. In late 2011 and early 2012, we acquired approximately 2,363 square kilometers of 3D seismic data in Essaouira Offshore block and processing is ongoing.

Effective December 6, 2013, we entered into the Tarhazoute Offshore Petroleum Agreement as operator with a 75% participating interest. The Moroccan national oil company, ONHYM, has a 25% carried participating interest and is carried by Kosmos. We are required to pay a 10% royalty on oil produced in water depths of 200 meters or less (the first 300,000 tons produced are exempt from royalty) and 7% royalty on oil produced in water depths deeper than 200 meters (the first 500,000 tons produced are exempt from royalty). These royalties are to be paid in-kind or, at the election of the government of Morocco, in cash. A corporate tax rate of 30% is applied to profits at the license level following a 10-year tax holiday post first production. The Tarhazoute Offshore block comprises approximately 1.9 million acres (7,753 square kilometers). The exploration term of the Tarhazoute Offshore Permits, beginning December 9, 2013, is eight years and includes an initial exploration period of two years and six months followed by the first extension period of two years and six months and the second extension period of three years. In the event of commercial success, we have the right to develop and produce oil and/or gas for a period of 25 years from the grant of an exploitation authorization from the government, which may be extended for an additional period of 10 years under certain circumstances.

In October 2013, we entered into three farm-out agreements with BP covering our three blocks in the Agadir Basin, offshore Morocco. Under the terms of the agreements, BP will acquire a non-operating interest in each of the Essaouira Offshore, Foum Assaka Offshore and Tarhazoute Offshore blocks. BP will fund Kosmos' share of the cost of one exploration well in each of the three blocks, subject to a maximum spend of $120.0 million per well, and pay its proportionate share of any well costs above the maximum spend. In the event a second exploration well is drilled in any block, BP will pay 150% of its share of costs subject to a maximum spend of $120.0 million per well. Upon close of the transaction, BP shall also pay $36.3 million for their share of past costs and $8.9 million for their portion of shared costs incurred from the effective date of the contract through December 31, 2013. Completion of the transactions is subject to customary closing conditions, including Moroccan Government approvals. After completing the transaction, our participating interests will be 30.0%, 29.925% and 30.0% in the Essaouira Offshore, Foum Assaka Offshore and Tarhazoute Offshore blocks, respectively, and we will remain the operator.

Suriname Exploration Agreements

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

On December 13, 2011, we signed a petroleum contract covering Offshore Block 45 located offshore Suriname. We have a 50% participating interest in the block and are the operator. Staatsolie, Suriname's national oil company, will be carried through the exploration and appraisal phases and has the option to back into the contract with an interest of not more than 15% upon approval of a development plan. The Block 45 petroleum contract provides for us to recover our share of expenses incurred ("cost recovery oil") and our share of remaining oil ("profit oil"). Cost recovery oil is apportioned to Kosmos from up to 80% of gross production prior to profit oil being split between the government of Suriname and the contractor. Profit oil is then apportioned based upon "R-factor" tranches, where the R-factor is cumulative net revenues divided by cumulative net investment. A corporate tax rate of 36% is applied to profits. The initial period of the exploration phase is three years and there are two renewal periods consisting of two years each. Each renewal period carries a one well drilling obligation. In the event of commercial success, the duration of the contract will be 30 years from the effective date or 25 years from governmental approval of a plan of development, whichever is longer. Block 45 comprises approximately 1.3 million acres (approximately 5,126 square kilometers). In November 2012, Kosmos closed an agreement with Chevron under which Kosmos assigned half of its interest in Block 45, offshore Suriname, to Chevron. Each party now has a 50% participating interest in Block 45.

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.

Mauritania Exploration Agreements

Effective June 15, 2012, we entered into three petroleum contracts covering offshore Mauritania blocks C8, C12 and C13 with the Islamic Republic of Mauritania. We have a 90% participating interest and are the operator. The Mauritanian national oil company, Société Mauritanienne des Hydrocarbures ("SMH") now called Société Mauritanienne des Hydrocarbures et de Patrimoine Minier ("SMHPM"), currently has a 10% carried participating interest during the exploration period only. Should a commercial discovery be made, SMHPM's 10% carried interest is extinguished and SMHPM will have an option to acquire a participating interest of 10% to 14%. SMHPM's interest in a commercial development will not be carried as to appraisal and development costs. Cost recovery oil is apportioned to Kosmos from up to 55% of total production prior to profit oil being split between the government of Mauritania and the contractor. Profit oil is then apportioned based upon "R-factor" tranches, where the R-factor is cumulative net revenues divided by the cumulative investment. We are required to pay a royalty of 7%. These royalties are to be paid in-kind or, at the election of the government of Mauritania, in cash. A corporate tax rate of 27% is applied to profits at the license level. The Blocks C8, C12 and C13 currently comprise approximately 2.9 million acres (11,900 square kilometers), 1.7 million acres (7,075 square kilometers) and 1.9 million acres (7,800 square kilometers) respectively. The terms of exploration periods of these Offshore Blocks are all ten years and include an initial exploration period of four years followed by the first extension period of three years and the second extension period of three years. Kosmos is currently in the first exploration period of the blocks, expiring in June 2016. 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.

Ireland Exploration Agreements

Effective April 17, 2013, we entered into three farm-in agreements, whereby we have an 85% participating interest in Frontier Exploration License 2/13 and 3/13, and a 75% participating interest in Frontier Exploration License 1/13, all part of the Porcupine Basin, offshore Ireland. We are the operator of the three blocks. We completed 3D seismic acquisition over the blocks and processing of the data is underway.

In Frontier Exploration License 2/13 and 3/13, Europa has a 15% participating interest in the areas. Each License comprises approximately 0.2 million acres (700 square kilometers). In addition to the fully funded 3D seismic acquisition, we will also fund 100% of the costs of the first exploration well on each block, subject to an investment cap. The per-well investment cap for the first well is

$90.0 million on Frontier Exploration License 2/13 and $110.0 million on Frontier Exploration License 3/13.

In Frontier Exploration License 1/13, Antrim has a 25% participating interest in the area. The License comprises approximately 0.3 million acres (1,000 square kilometers). We have fully funded the 3D seismic program on the block.

We are required to pay a corporate income tax rate of 25% and potentially a petroleum resource rent tax of between 0% and 15% as determined by a profitability-based sliding scale.

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 staff that are substantially larger than ours. As a result, our competitors may be able to pay more for desirable oil and natural gas assets, or to evaluate, bid for and purchase a greater number of licenses than our financial or personnel resources will permit. Furthermore, these companies may also be better able to withstand the financial pressures of 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 in 2010 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.

Capping and Containment

We entered into an agreement with a third party service provider to supply subsea capping and containment equipment on a global basis. The equipment includes capping stacks, debris removal, subsea dispersant and auxillary equipment. The equipment meets industry accepted standards and can be deployed by air cargo and other conventional means to suit multiple application scenarios. We also developed an emergency response plan and response organization to prepare and demonstrate the Company's readiness to respond to a subsea well control incident.

Oil Spill Response

To complement our agreement discussed above for subsea capping and containment equipment, we became a charter member of the Global Dispersant Stockpile. The new dispersant stockpile, which is managed by Oil Spill Response Limited ("OSRL") of Southampton, United Kingdom ("UK"), an oil spill response contractor, consists of 5,000 cubic meters of dispersant strategically located at OSRL bases around the world. The total volume of the stockpile located at OSRL bases around the world is approximate to the amount used in the Macondo response.

Ghana

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. More than 200 personnel (composed primarily of Tullow and Kosmos employees, Ghanaian Navy, Ghana EPA,Maritime Authority, Petroleum Commission, Ports and Harbor personnel, local contractors and community representatives) 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 OSRL.

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 respond in a timely manner as intended, perform as designed or be able to fully contain or cap any oil spill, blow-out or uncontrolled flow of hydrocarbons.

Morocco

We recently developed an Oil Spill Contingency Plan to support our drilling operations. The plan calls for the addition of Tier 1 spill equipment to our shorebase in Agadir, Morocco to respond to a harbor or shoreline incident in the area. We will have access to additional Tier 2 and Tier 3 equipment from the Southampton, UK location.

Per common industry practice, under the agreements currently in place, or agreements we may enter into during the future, governing the terms of use of the drilling rigs 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, or expect to maintain, upon commencement of drilling operations, insurance coverage typical of the industry in the areas we operate in; these include property damage insurance, loss of production insurance, wreck removal insurance, control of well insurance, general liability including pollution liability to cover pollution from wells and other operations. We also participate in an insurance coverage program for the Jubilee FPSO. Our insurance is, or will be, carried in amounts typical for the industry and relative to our size and operations and in accordance with our contractual and regulatory obligations.

Other Regulation of the Oil and Gas Industry

Ghana

The Ghanaian Petroleum Law currently governs the upstream Ghanaian oil and natural gas regulatory regime and sets out the policy and framework for industry participants. All petroleum found in its natural state within Ghana is deemed to be national property and is to be developed on behalf of the people of Ghana. GNPC is empowered to carry out exploration and development work either on its own or in association with local or foreign contractors. Companies who wish to gain rights to explore and produce in Ghana can only do so by entering into a petroleum agreement with 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." The Petroleum (Local Content and Local Participation in Petroleum Activities) Regulations comes into effect in February 2014. The Regulations mandate certain levels of local participation in service companies, in-country manufacturing of goods and the provision of services, and certain reporting requirements.

Ireland

The primary legislative acts relevant to our operations in the Republic of Ireland are: (1) The Petroleum and Other Minerals Development Act, 1960 (the "Irish Petroleum Act") and (2) the Gas Act, 1960. The Ministry of Communications, Energy and Natural Resources is the regulatory authority tasked with maximizing the benefits to the Irish State from exploration for and production of indigenous oil and gas resources. The Irish Petroleum Act vests all State petroleum in the Minister. Only the Minister, licensees under an exploration license, a petroleum prospecting license, or a reserved area license, and lessees under a valid petroleum lease may search for petroleum. The Ministry enters into petroleum agreements (licenses for exploration and leases for development and production) on behalf of the State. Assignments of interests in licenses also require the consent of The Ministry. The relevant tax law is the Taxes Consolidation Act, 1997, as amended by the Finance Act, 1999. The current license and lease terms are found in the Licensing Terms for Offshore Oil and Gas Exploration, Development & Production, 2007.

Mauritania

The main legislative acts in the Islamic Republic of Mauritania relevant to petroleum exploration and production are Law No. 2010-033 dated July 20, 2010 and its amendment (the "Hydrocarbon Laws"). The regulatory authority in Mauritania is the Ministry of Petroleum, Energy and Mines and the national oil company acting on its behalf is SMHPM. SMHPM was instituted by Decree No. 2005-106 of November 7, 2005 and modified by Decree No. 2009-168 of May 3, 2009 and Decree No. 2014-01. Pursuant to the Hydrocarbon Laws, Mauritania or SMHPM may undertake petroleum operations and may authorize other legal entities to undertake petroleum operations under exploration-production contracts. The Ministry shall sign petroleum contracts on behalf of Mauritania. Assignments of interests in petroleum contracts also require the consent of The Ministry. The exploration period shall not be more than ten years, subject to certain permitted extensions and the exploitation period shall not be more than 25 years. Petroleum contracts may provide that Mauritania has a carried interest of up to 10% during the exploration period. Petroleum contracts shall grant Mauritania the option to participate for a percentage not less than 10% 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 contract with the Moroccan State. Therefore, companies who wish to gain rights to explore and produce in Morocco can only do so by entering into a petroleum contract with ONHYM acting on behalf of the State. It is further provided that the State of Morocco (via ONHYM) shall retain a participation in exploration permits or exploitation concessions which shall not be in excess of 25%. More generally, ONHYM is representing the State of Morocco for licensing, exploration and exploitation matters within the limit of its prerogatives set out pursuant to the Law 33-01. Assignments of interests in exploration permits also require the consent of the administration pursuant to the Law 21-90.

The 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 block 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 was founded in 1980 as a state enterprise and holds mining rights onshore and offshore in

Suriname. The Suriname Petroleum Law granted state enterprises with petroleum concession rights the authority, upon the approval of the Minister of Natural Resources, to enter into petroleum contracts with 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. Assignments of interests in petroleum contracts also require the consent of Staatsolie and/or The Minister of Natural Resources.

Certain Bermuda Law Considerations

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

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

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

Employees

As of December 31, 2013, 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. A portion of our oil and natural gas assets consists of discoveries without approved PoDs and with limited well penetrations, as well as identified yet unproven prospects based on available seismic and geological information that indicates the potential presence of hydrocarbons. However, the areas we decide to drill may not yield oil or natural gas in commercial quantities or quality, or at all. Many of our current discoveries and all of our prospects are in various stages of evaluation that will require substantial additional analysis and interpretation. Even when properly used and interpreted, 2D and 3D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. Accordingly, we do not know if any of our discoveries or prospects will contain oil or natural gas in sufficient quantities or quality to recover drilling and completion costs or to be economically viable. Even if oil or natural gas is found on our discoveries or prospects in commercial quantities, construction costs of gathering lines, subsea infrastructure and floating production systems and transportation costs (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 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 deepwater offshore Morocco, Suriname, Mauritania and Ireland 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 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 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 addition, a successful discovery would require significant capital expenditure in order to develop and produce oil, even if we deemed such discovery to be commercially viable. See "—Our business plan requires substantial additional capital, which we may be unable to raise on acceptable terms or at all in the future, which may in turn limit our ability to develop our exploration, appraisal, development and production activities." In the areas in which we operate, we face higher above-ground risks necessitating higher expected returns, the requirement for increased capital expenditures due to a general lack of infrastructure and underdeveloped oil and gas industries, and increased transportation expenses due to geographic remoteness, which either require a single well to be exceptionally productive, or the existence of multiple successful wells, to allow for the development of a commercially viable field. See "—Our operations may be adversely affected by political and economic circumstances in the countries in which we operate." Furthermore, if our actual drilling and development costs are significantly more than our estimated costs, we may not be able to continue our business operations as proposed and could be forced to modify our plan of operation.

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.

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 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 contract in Cap Boujdour Offshore block, Western Sahara, and have provided notice to enter the first extension period commencing March 5, 2014 and expiring March 5, 2016. Also in Morocco, we are currently in the initial exploration phase of the Essaouira Offshore block (expiring May 8, 2014) and the Tarhazoute Offshore block (the Tarhazoute Petroleum Agreement effective on December 6, 2013, however, permits have not yet been issued to establish term of the initial exploration phase). Additionally, we are currently in the first extension period for the Foum Assaka Offshore block in Morocco expiring on July 1, 2016. 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.

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.

We are currently in the initial exploration phases under our Frontier Exploration Licenses 1-13, 2-13, and 3-13 offshore Ireland. 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.

The exploration phase of the WCTP and DT PAs have expired. Pursuant to the terms of such PAs, while we and our respective block partners have certain rights to negotiate new petroleum agreements with respect to the WCTP Relinquishment Area and the DT Relinquishment Area, we cannot assure you that we will determine to enter any such new petroleum agreements. 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%. An additional redetermination could occur sometime 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, or the scope, of exploration or development activities or the amount of capital expenditures and, therefore, may not be able to carry out one of our key business strategies of minimizing the cycle time between discovery and initial production. The success and timing of exploration and development activities operated by our block partners will depend on a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the operator's expertise and financial resources;
- approval of other block partners in drilling wells;
- the scheduling, pre-design, planning, design and approvals of activities and processes;
- selection of technology; and
- the rate of production of reserves, if any.

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

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

The process of estimating oil and natural gas reserves is technically complex. It requires interpretations of available technical data and many assumptions, including those relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this report. See "Item 1. Business—Our Reserves" for information about our estimated oil and natural gas reserves and the present value of our net revenues at a 10% discount rate ("PV-10") and Standardized Measure of discounted future net revenues (as defined herein) as of December 31, 2013.

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 PV-10 and the Standardized Measure as of December 31, 2013 would each decrease by approximately $21.5 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, or the timing of, are not sufficient to cover such costs.

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

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

We do not currently have any commitments for future external funding beyond the capacity of our commercial debt facility and revolving credit facility. Additional financing may not be available on favorable terms, or at all. Even if we succeed in selling additional equity securities to raise funds, at such time the ownership percentage of our existing shareholders would be diluted, and new investors may demand rights, preferences or privileges senior to those of 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."

All of our proved reserves, oil production and cash flows from operations are currently associated with our licenses offshore Ghana. Should any event occur which adversely affects such proved reserves, oil production and cash flows from these licenses, including, without limitation, any event resulting from the risks and uncertainties outlined in this "Risk Factors" section, our business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures may be materially and adversely affected.

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 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.

In Ghana, we currently produce associated gas from the Jubilee Field. While the Government of Ghana is in the process of constructing a gas pipeline from the Jubilee Field to transport such natural gas for processing and sale, to date the pipeline has not been completed. Further, even if the pipeline was completed, we granted the first 200 BCF of natural gas from the Jubilee Phase 1 to Ghana at no cost. Thus, in Ghana, even if the infrastructure was in place for natural gas processing and sales, it would still be quite some time before we would be able to commercialize our Ghana natural gas.

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 is in the process of completing the construction and connection of a gas pipeline from the Jubilee Field to transport such natural gas to the mainland for processing and sale; however, to date, the construction of the pipeline and the onshore plant has not been completed and the Company is presently unable to predict with certainty when completion will occur, as several previous completion dates have passed. 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 remove excess natural gas from the reservoirs' production system via such pipeline or by flaring it. We expect that we will need to flare large quantities of natural gas prior to the completion of the pipeline. However, we have not been issued a permit from the Ghana EPA to flare natural gas produced from the Jubilee Field in substantial quantities. Our petroleum agreements allow the operator to flare gas in certain circumstances to include, without limitation, in circumstances where reinjection is not possible. Ghanaian regulators may claim regulatory uncertainty exists as to whether Ghana EPA or other permits are also needed to conduct such flaring. In the absence of completion of a natural gas pipeline or if we are unable 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. Alternatively, if we flare without an amended Ghana EPA permit, we may be subject to regulatory action.

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

In the event that our currently undeveloped discoveries and prospects are developed and become operational, they may not produce oil and natural gas in commercial quantities or at the costs anticipated, and our projects may cease production, in part or entirely, in certain circumstances. Discoveries may become uneconomic as a result of an increase in operating costs to produce oil and natural gas. Our actual operating costs and rates of production may differ materially from our current estimates. Moreover, it is possible that other developments, such as increasingly strict environmental, climate change, health and safety laws and regulations and enforcement policies thereunder and claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities, delays, an inability to complete the development of our discoveries or the abandonment of such discoveries, which could cause a material adverse effect on our financial condition and results of operations.

We are subject to drilling and other operational 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, lower production rates, adverse publicity, substantial losses and civil or criminal liability. In accordance with customary industry practice, we expect to maintain insurance against some, but not all, of these risks and losses. The occurrence of any of these events, whether or not covered by insurance, could have a material adverse effect on our financial position and results of operations.

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

Historically, some oil and natural gas development projects have experienced delays and capital cost increases and overruns due to, among other factors, the unavailability or high cost of drilling rigs and other essential equipment, supplies, personnel and oilfield services, as well as mechanical and technical issues. The cost to develop our projects has not been fixed and remains dependent upon a number of factors, including the completion of detailed cost estimates and final engineering, contracting and procurement costs. Our construction and operation schedules may not proceed as planned and may experience delays or cost overruns. Any delays may increase the costs of the projects, requiring additional capital, and such capital may not be available in a timely and cost-effective fashion.

Our offshore and deepwater operations will involve special risks that could adversely affect our results of operations.

Offshore operations are subject to a variety of operating risks specific to the marine environment, such as capsizing, sinking, collisions and damage or loss to pipeline, subsea or other facilities or from weather conditions. We could incur substantial expenses that could reduce or eliminate the funds available for exploration, development or license acquisitions, or result in loss of equipment and license interests.

Deepwater exploration generally involves greater operational and financial risks than exploration in shallower waters. Deepwater drilling generally requires more time and more advanced drilling technologies, involving a higher risk of equipment failure and usually higher drilling costs. In addition, there may be production risks of which we are currently unaware. If we participate in the development of new subsea infrastructure and use floating production systems to transport oil from producing wells, these operations may require substantial time for installation or encounter mechanical difficulties and equipment failures that could result in loss of production, significant liabilities, cost overruns or delays.

For example, during 2013, we experienced mechanical issues in the Jubilee Field, including failures of our water injection facilities on the FPSO and water and gas injection wells. This equipment downtime negatively impacted oil production during the year. Furthermore, deepwater operations generally, and operations in Africa and South America, in particular, lack the physical and oilfield service infrastructure present in other regions. As a result, a significant amount of time may elapse between a deepwater discovery and the marketing of the associated oil and natural gas, increasing both the financial and operational risks involved with these operations. Because of the lack of and the high cost of this infrastructure, further discoveries we may make in Africa, South America and Europe may never be economically producible.

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 Jubilee 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, assertions that could be read to give rise to taxes payable under the Ghanaian Tax Law in connection with our IPO, failure to approve PoDs relating to certain discoveries offshore Ghana and the relinquishment of certain exploration areas on our licensed blocks offshore Ghana. These past disagreements have been resolved. The resolution of certain of these disagreements required us to pay agreed settlement costs to GNPC and/or the government of Ghana.

There can be no assurance that future disagreements will not arise with any host government and/or national oil companies that may have a material adverse effect on our exploration or development activities, our ability to operate, our rights under our licenses and local laws or our rights to monetize our interests.

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

Our current exploration licenses are located in Africa, South America and Europe. Some or all of these licenses could be affected should 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 in Africa and South America may be subject to higher political and security risks than those operations under the sovereignty of the United States. We plan to maintain insurance coverage for only a portion of the risks we face from doing business in these regions. There also may be certain risks covered by insurance where the policy does not reimburse us for all of the costs related to a loss.

Further, as many of our licenses are concentrated in the same geographic area, a number of our licenses could experience the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of licenses.

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

Oil and natural gas exploration, development and production activities are subject to political and economic uncertainties (including but not limited to changes in energy policies or the personnel administering them), changes in laws and policies governing operations of foreign-based companies, expropriation of property, cancellation or modification of contract rights, revocation of consents or approvals, obtaining various approvals from regulators, foreign exchange restrictions, currency fluctuations, royalty increases and other risks arising out of foreign governmental sovereignty, as well as risks of loss due to civil strife, acts of war, guerrilla activities, terrorism, acts of sabotage, territorial disputes and insurrection. In addition, we are subject both to uncertainties in the application of the tax laws in the countries in which we operate and to possible changes in such tax laws (or the application thereof), each of which could result in an increase in our tax liabilities. These risks may be higher in the developing countries in which we conduct a majority of our activities, as it is the case in Ghana, where the Ghanaian Revenue Authority (the "GRA") has disputed certain tax deductions we have claimed in our Ghanaian tax returns covering the past seven fiscal years as non-allowable under the terms of the Ghanaian Petroleum Income Tax Law, as well as non-payment of certain transactional taxes.

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

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

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

Furthermore, various activist groups have mounted public relations campaigns to force companies to cease and divest operations in Western Sahara, and we could come under similar public pressure. Some investors have refused to invest in companies with operations in Western Sahara, and we could be subject to similar pressure. Any of these factors could have a 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, is intensely competitive and many of our competitors possess and employ substantially greater resources than us.

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

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

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

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

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

For example, Ghana's Parliament has enacted the Petroleum Revenue Management Act and is considering the enactment of a new Petroleum Exploration and Production Act. There can be no assurance that these laws will not seek to retroactively, either on their face or as interpreted, modify the terms of the agreements governing our license interests in Ghana, including the WCTP and DT PAs and the UUOA, require governmental approval for transactions that effect a direct or indirect change of control of our license interests or otherwise affect our current and future operations in Ghana. Any such changes may have a material adverse effect on our business. We also cannot assure you that government approval will not be needed for direct or indirect transfers of our petroleum agreements or interests thereunder based on existing legislation. See "Item 1. Business—Other Regulation of the Oil and Gas Industry—Ghana."

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

We 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 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, including Ghana, Ireland, Mauritania, Morocco and Suriname, have agreed to reduce emissions of greenhouse gases ("GHGs"), including methane (a primary component of natural gas) and carbon dioxide (a byproduct of oil and natural gas combustion) under the Kyoto Protocol. While the Kyoto Protocol was set to expire in 2012, it has been extended by amendment until 2020 with the understanding among the parties that a new climate change regime will be negotiated by 2015 and succeed the Kyoto Protocol in 2020. Ireland is also a party to the European Union Emissions Trading Scheme that seeks, among other things, to meet the European Union's commitments under the Kyoto Protocol through a "cap and trade" GHG emissions framework. The increased regulation of GHGs 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 our assets are located or in which we otherwise operate, including through increased severity and frequency of storms, floods and other weather events, could adversely impact our operations or disrupt transportation or other process-related services provided by our third-party contractors.

Environmental, health and safety laws are complex, change frequently and have tended to become increasingly stringent over time. Our costs of complying with current and future climate change, environmental, health and safety laws, the actions or omissions of our block partners and third party contractors and our liabilities arising from releases of, 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, 2013, we had $900.0 million outstanding and $600.0 million of committed undrawn capacity under our commercial debt facility, of which $309.5 million was available. As of December 31, 2013, there were no borrowings outstanding under the Corporate Revolver and the undrawn availability was $300.0 million As of December 31, 2013, there were six outstanding letters of credit totaling $42.0 million under the letter of credit facility agreement. 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 the past, legislation has been introduced in the Congress of the United States that would reform the U.S. tax laws as they apply to certain non-U.S. entities and operations, including legislation that would treat a foreign corporation as a U.S. corporation for U.S. federal income tax purposes if substantially all of its senior management is located in the United States. If this or similar legislation is passed that changes our U.S. tax position, it could have a material adverse effect on our net income, our cash flow and our financial condition.

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

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

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

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

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

We use derivative instruments to manage our commodity price and interest rate risk. The United States Congress adopted comprehensive financial reform legislation in 2010 that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as ours, that participate in that market. The Dodd-Frank Act was signed into law by the President on July 21, 2010. 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. We are vigorously defending 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 63% 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. Some of our directors are not residents of the United States, and a substantial portion of our assets are located outside the United States. As a result, it may be difficult for investors to effect service of process on that person in the United States or to enforce in the United States judgments obtained in U.S. courts against us or that person based on the civil liability provisions of the U.S. securities laws. It is doubtful whether courts in Bermuda will enforce judgments obtained in other jurisdictions, including the United States, against us or our directors or officers under the securities laws of those jurisdictions or entertain actions in Bermuda against us or our directors or officers under the securities laws of other jurisdictions.

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

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

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

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

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

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

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

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

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

See "Item 1. Business." We also have various operating leases for rental of office space, office and field equipment, and vehicles. See Note 15 of Notes to the Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for the future minimum rental payments. Such information is incorporated herein by reference.

Item 3. Legal Proceedings

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. Additionally, Warburg Pincus LLC and Blackstone Capital Partners were subsequently dismissed as defendants from these lawsuits. 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.

	2013		2012	
	High	Low	High	Low
First Quarter	$ 13.05	$ 10.15	$ 15.13	$ 12.30
Second Quarter	12.17	10.09	13.70	10.03
Third Quarter	11.15	9.71	11.75	8.19
Fourth Quarter	11.42	10.03	12.65	9.55

As of February 18, 2014, 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 212. On February 18, 2014, the last reported sale price of Kosmos' common shares, as reported on the NYSE, was $10.66 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. Currently we do not anticipate paying any dividends in the foreseeable future.

Unregistered Sales of Equity Securities and Use of Proceeds

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

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

During 2013, 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 consist of highly rated investment funds.

Issuer Purchases of Equity Securities

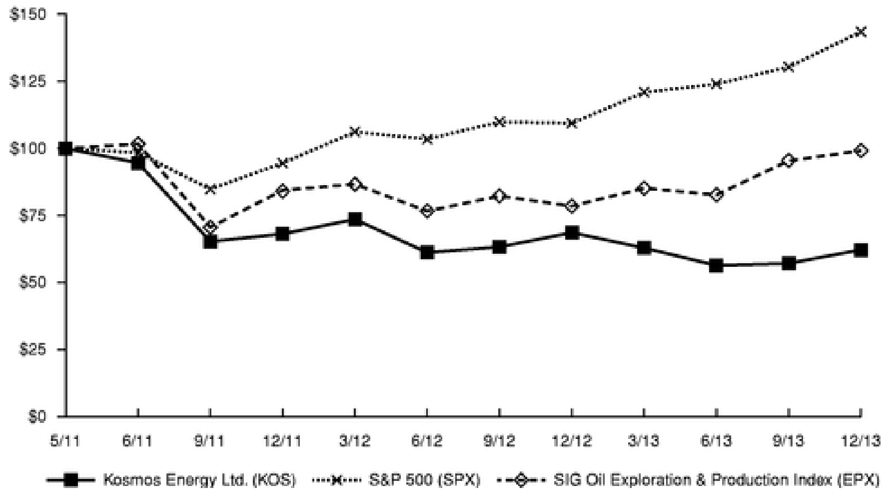
Under the terms of our Long Term Incentive Plan ("LTIP"), we have issued shares of restricted shares and restricted share units to our employees. On the date that these restricted shares and restricted share units vest, we provide such employees the option to withhold, via a net exercise provision pursuant to our applicable restricted share award agreements and the LTIP, the number of vested shares (based on the closing price of our common shares on such vesting date) equal to tax liability owed by such grantee. The shares withheld from the grantees to settle their tax liability are reallocated to the number of shares available for issuance under the LTIP. The following table outlines the total number of shares withheld during fiscal year 2013 and the average price paid per share.

	Total Number of Share Withheld/Purchased (In thousands)	Average Price Paid per Share
January 1, 2013—January 31, 2013	—	$ —
February 1, 2013—February 28, 2013	—	—
March 1, 2013—March 31, 2013	6	12.51
April 1, 2013—April 30, 2013	189	10.91
May 1, 2013—May 31, 2013	899	11.52
June 1, 2013—June 30, 2013	12	10.32
July 1, 2013—July 31, 2013	—	—
August 1, 2013—August 31, 2013	—	—
September 1, 2013—September 30, 2013	—	—
October 1, 2013—October 31, 2013	3	10.42
November 1, 2013—November 30, 2013	—	—
December 1, 2013—December 31, 2013	—	—
Total	1,109	11.41

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, 2013, in cumulative total stockholder return on our common shares as measured against the cumulative total return of the S&P 500 Index and the SIG Oil Exploration & Production Index. The graph tracks the performance of a $100 investment in our common shares and in each index (with the reinvestment of all dividends).



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

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Item 6. Selected Financial Data

The following selected consolidated financial information set forth below as of and for the five years ended, December 31, 2013, 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,				
	2013	2012	2011(1)	2010	2009
	(In thousands, except per share data)				
Revenues and other income:					
Oil and gas revenue	$ 851,212	$ 667,951	$ 666,912	$ —	$ —
Interest income	275	1,108	9,093	4,231	985
Other income	941	3,150	775	5,109	9,210
Total revenues and other income	852,428	672,209	676,780	9,340	10,195
Costs and expenses:					
Oil and gas production	96,791	95,109	83,551	—	—
Exploration expenses	230,314	100,652	128,753	73,126	22,127
General and administrative	158,421	157,087	111,235	98,967	55,619
Depletion and depreciation	222,544	185,707	140,469	2,423	1,911
Amortization—deferred financing costs	11,054	8,984	16,193	28,827	2,492
Interest expense	36,811	52,207	65,749	59,582	6,774
Derivatives, net	17,027	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	3,512	1,475	149	1,094	46
Total costs and expenses	776,474	638,053	577,737	332,120	88,969
Income (loss) before income taxes	75,954	34,156	99,043	(322,780)	(78,774)
Income tax expense (benefit)	166,998	101,184	76,686	(77,108)	973
Net income (loss)	$ (91,044)	$ (67,028)	$ 22,357	$ (245,672)	$ (79,747)
Accretion to redemption value of convertible preferred units	—	—	(24,442)	(77,313)	(51,528)
Net loss attributable to common shareholders/unit holders	$ (91,044)	$ (67,028)	$ (2,085)	$ (322,985)	$ (131,275)
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	$ (0.24)	$ (0.18)	$ 0.09		
Diluted	$ (0.24)	$ (0.18)	$ 0.09		
Weighted average number of shares used to compute net income (loss) per share (the year ended December 31, 2011 represents the period from May 16, 2011 to December 31, 2011)(2):					
Basic	376,819	371,847	368,474		
Diluted	376,819	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,				
	2013	2012	2011	2010	2009
	(In thousands)				
Cash and cash equivalents	$ 598,108	$ 515,164	$ 673,092	$ 100,415	$ 139,505
Total current assets	734,961	750,118	1,112,481	559,920	256,728
Total property and equipment, net	1,522,962	1,525,762	1,377,041	998,000	604,007
Total other assets	87,903	90,243	62,412	133,615	161,322
Total assets	2,345,826	2,366,123	2,551,934	1,691,535	1,022,057
Total current liabilities	219,324	190,253	339,607	482,057	139,647
Total long-term liabilities	1,134,167	1,146,964	1,191,601	845,383	287,022
Total convertible preferred units	—	—	—	978,506	813,244
Total shareholders' equity/unit holdings equity	992,335	1,028,906	1,020,726	(614,411)	(217,856)
Total liabilities, convertible preferred units and shareholders' equity/unit holdings equity	2,345,826	2,366,123	2,551,934	1,691,535	1,022,057

Consolidated Statements of Cash Flows Information:

	Years Ended December 31,				
	2013	2012	2011	2010	2009
	(In thousands)				
Net cash provided by (used in):					
Operating activities	$ 522,404	$ 371,530	$ 364,909	$ (191,800)	$ (27,591)
Investing activities	(324,133)	(402,662)	(385,140)	(589,975)	(500,393)
Financing activities	(115,327)	(126,796)	592,908	742,685	519,695

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 along the Atlantic Margin. Our assets include existing production and other major development projects offshore Ghana, as well as exploration licenses with significant hydrocarbon potential offshore Ireland, Mauritania, Morocco (including Western Sahara) and Suriname.

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

Debt

Our commercial debt facility ("Facility") provides a revolving-credit and letter of credit facility with a total commitment of $1.5 billion. The availability period for the revolving-credit facility, as amended in April 2013, expires on December 15, 2014 and the letter of credit sublimit expires on the final maturity date. The available facility amount is subject to borrowing base constraints and, beginning on December 15, 2014, outstanding borrowings will also be constrained by an amortization schedule. The first required payment could be as early as March 31, 2015, subject to the level of outstanding borrowings and the borrowing base constraints.

In September 2013, as part of the normal borrowing base determination process, the availability under the Facility was reduced to $1.2 billion. As of December 31, 2013, borrowings under the Facility totaled $900.0 million, the undrawn availability under the Facility was $309.5 million and there were no letters of credit drawn under the facility.

In April 2013, the availability under the Corporate Revolver was increased from $260.0 million to $300.0 million by additional commitments from existing and new financial institutions.

In July 2013, we entered into a revolving letter of credit facility agreement ("LC Facility"). The size of the LC Facility is $100.0 million, with additional commitments up to $50.0 million being available if the existing lender increases its commitments or if commitments from new financial institutions are added. The LC Facility provides that we shall maintain cash collateral in an amount equal to at least 75% of all outstanding letters of credit under the LC Facility, provided that during the period of any breach of certain financial covenants, the required cash collateral amount shall increase to 100%. The fees associated with outstanding letters of credit issued will be 0.5% per annum. The LC Facility has an availability period which expires on June 1, 2016. We may voluntarily cancel any commitments available under the LC Facility at any time. As of December 31, 2013, there were six outstanding letters of credit totaling $42.0 million under the LC Facility.

Rig Agreement

In June 2013, we signed a long-term rig agreement with a subsidiary of Atwood Oceanics, Inc. for the new build drillship "Atwood Achiever." Currently under construction, the rig is expected to commence drilling operations in the second half of 2014. The rig's capabilities include drilling to total depths of up to 40,000 feet (12,200 meters), and in water depths of up to 12,000 feet (3,660 meters). The rig agreement covers an initial period of three years at a day rate of approximately $0.6 million, with an option to extend the agreement for an additional three-year term.

Ghana

During 2013, we had eight liftings of oil totaling 7,778 MBbl from the Jubilee Field production resulting in revenues of $851.2 million. Our average realized price was $109.44 per barrel.

We previously received an approval for the Phase 1A PoD of the Jubilee Field, and production from Phase 1A commenced in late 2012. The Phase 1A program includes the drilling of up to eight additional wells consisting of up to five production wells and three water injection wells. Five wells (three producers and two injectors) are online. Program execution is expected to be completed in 2014.

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 did not have a material impact on our consolidated financial statements for the year ended December 31, 2013 or 2012, as we previously recorded the unsuccessful well costs associated with the Banda-1 exploration well as exploration expenses in 2011.

The Sapele-1 exploration well on the DT Block was completed in February 2013. The well was not considered a productive well and accordingly was plugged and abandoned.

In May 2013, the government of Ghana approved the PoD over the Tweneboa, Enyenra and Ntomme ("TEN") discoveries. Development of TEN will include the drilling and completion of up to 24 development wells, half of the wells designed as producers and the remainder as water or gas injectors to support ultimate field recoveries. The TEN development is expected to deliver first oil in 2016. Future development of gas resources at TEN is anticipated following the commencement of oil startup.

Drilling of the Akasa-2A appraisal well on the WCTP Block was completed in October 2013. We believe that the well successfully identified the down dip water contact associated with the Akasa-1 discovery as intended. Should the Akasa discovery progress to a development, the Akasa-2A appraisal well is expected to be utilized in the development as a water injection well. However, since the Akasa-2A appraisal well did not encounter oil or gas reserves sufficient to be utilized as a producing well, accounting rules require that the costs associated with the Akasa-2A appraisal well be impaired. As such, $20.0 million is included in exploration expenses in the accompanying consolidated statement of operations for the year ended December 31, 2013.

Morocco

In January 2013, we closed on an agreement to acquire an additional 37.5% participating interest in the Essaouira Offshore block from Canamens Energy Morocco SARL, one of our block partners. Governmental approvals and processes for this acquisition were finalized in November 2013.

In August 2013, final government approvals and processes were completed for the acquisition of the additional 18.75% participating interest in the Foum Assaka block in the Agadir Basin offshore Morocco from Pathfinder, a wholly owned subsidiary of Fastnet, one of our block partners.

In October 2013, Kosmos executed a petroleum agreement with the Office National des Hydrocarbures et des Mines ("ONHYM"), the national oil company of the Kingdom of Morocco, covering the Tarhazoute Offshore block, to which the Company previously held certain exploration rights under a 2011 reconnaissance contract. Under the terms of the petroleum contract, the Company is the operator of the Tarhazoute Offshore block. ONHYM holds a 25% carried interest in the block through the exploration period. The initial exploration period will last for two years and six months and will commence from the date specified in the exploration permits, which have yet to be finalized with the Government of Morocco and ONHYM. The exploration period may be extended for additional exploration extension periods of two years and six months and three years respectively. The petroleum contract is subject to customary government approvals.

In October 2013, we entered into three farm-out agreements with BP plc ("BP") covering three blocks in the Agadir Basin, offshore Morocco. Under the terms of the agreements, BP will acquire a non-operating interest in each of the Essaouira Offshore, Foum Assaka Offshore and Tarhazoute Offshore blocks. BP will fund Kosmos' share of the cost of one exploration well in each of the three blocks, subject to a maximum spend of $120.0 million per well, and pay its proportionate share of any well costs above the maximum spend. In the event a second exploration well is drilled in any block, BP will pay 150% of its share of costs subject to a maximum spend of $120.0 million per well. Upon close of the transaction, BP shall also pay $36.3 million for their share of past costs and $8.9 million for their portion of shared costs incurred from the effective date of the contract through December 31, 2013. Completion of the transactions is subject to customary closing conditions, including Moroccan Government approvals. After completing the transaction, our participating interests will be 30.0%, 29.925% and 30.0% in the Essaouira Offshore, Foum Assaka Offshore and Tarhazoute Offshore blocks, respectively, and we will remain the operator.

In October 2013, we entered into a farm-out agreement with Capricorn Exploration & Development Company Limited, a wholly owned subsidiary of Cairn Energy PLC ("Cairn"), covering the Cap Boujdour Offshore block, offshore Western Sahara. Under the terms of the agreement, Cairn will acquire a 20% non-operated interest in the exploration permits comprising the Cap Boujdour Offshore block. Cairn will pay 150% of its share of costs of a 3D seismic survey capped at $25.0 million and one exploration well capped at $100.0 million. In the event the exploration well is successful, Cairn will pay 200% of its share of costs on two appraisal wells capped at $100.0 million per well. Additionally, Cairn will contribute $12.3 million towards our future costs and, upon completion of the transaction, $0.6 million for their share of costs incurred from the effective date of the contract through December 31, 2013. Completion of the transaction is subject to customary closing conditions, including Moroccan Government approvals. After completing the transaction, our participating interest in the Cap Boujdour Offshore block will be 55.0% and we will remain the operator.

Ireland

In April 2013, the Company entered into a farm-in agreement with Antrim Energy Inc., whereby Kosmos acquired a 75% participating interest and operatorship, covering Licensing Option 11/5 offshore the west coast of Ireland. As part of the agreement, Kosmos will reimburse a portion of previously-incurred exploration costs, as well as carry the partner on future 3D seismic costs.

In April 2013, the Company entered into a farm-in agreement with Europa Oil & Gas (Holdings) plc, whereby Kosmos acquired an 85% participating interest and operatorship, covering Licensing Option 11/7 and 11/8 offshore the west coast of Ireland. As part of the agreement, Kosmos will reimburse a portion of previously incurred exploration costs, as well as carry the partner on future

3D seismic costs. Contingent upon an election by Kosmos and our partner to enter into a subsequent exploration drilling phase on one or both of the blocks, Kosmos will also fund 100% of the costs of the first exploration well on each block, subject to an investment cap of $90.0 million and $110.0 million, respectively, on each block.

In July 2013, Ireland granted us Frontier Exploration Licenses 1-13, 2-13, and 3-13 pursuant to Licensing Options 11/5, 11/7 and 11/8. The term of each contract is 15 years unless surrendered or revoked, and is divided into an initial phase of three years, and three subsequent phases of four years each. Relinquishment of 25% of the existing area is required at the end of the first phase and 50% of the existing area at the end of the second phase. Three months before the end of each phase, we must propose a work program for the subsequent phase for the approval of the Minister of Communications, Energy and Natural Resources. The second phase work program must include an exploration well. The contract area must be surrendered if a second exploration well has not been commenced by the end of the third phase. Upon entering these Frontier Exploration Licenses, we and the other block partners relinquished approximately 25% of the acreage covered by the Licensing Options.

We completed a 3D seismic data acquisition program of approximately 5,000 square kilometers over these blocks in October 2013. The processing of this seismic data is expected to be completed in 2014.

Mauritania

In May 2013, we completed a 2D seismic data acquisition program on approximately 6,000 line-kilometers, covering Blocks C8, C12 and C13 offshore Mauritania. In November 2013, we completed a 3D seismic program of approximately 10,300 square kilometers over portions of Blocks C8 and C12. The processing of this seismic data is expected to be completed in 2014.

Suriname

In August 2013, we completed a 2D seismic program of approximately 1,400 line kilometers over a portion of Block 42, outside of the existing 3D seismic survey. Processing and interpretation of the data continues.

Cameroon

Drilling of the Sipo-1 exploration well on the Ndian River Block was completed in May 2013. Oil and gas shows evidenced during drilling indicated a working petroleum system; however, the well failed to encounter commercial reservoirs and accordingly was plugged and abandoned. Total well and other related costs of $75.6 million are included in exploration expenses in the accompanying consolidated statement of operations for the year ended December 31, 2013.

During 2013, we took all actions required to voluntarily relinquish all of the area under the Ndian River Block and Fako Block in Cameroon.

Results of Operations

All of our results, as presented in the table below, represent operations from the Jubilee Field in Ghana. Certain operating results and statistics for the years ended December 31, 2013, 2012 and 2011 are included in the following table:

	Years Ended December 31,		
	2013	2012	2011
	(In thousands, except per barrel data)		
Sales volumes:			
MBbl	7,778	5,905	5,971
Revenues:			
Oil sales	$ 851,212	$ 667,951	$ 666,912
Average sales price per Bbl	109.44	113.12	111.70
Costs:			
Oil production, excluding workovers	$ 57,608	$ 50,640	$ 83,551
Oil production, workovers	39,183	44,469	—
Total oil production costs	$ 96,791	$ 95,109	$ 83,551
Depletion	$ 213,732	$ 178,568	$ 135,532
Average cost per Bbl:			
Oil production, excluding workovers	$ 7.41	$ 8.58	$ 13.99
Oil production, workovers	5.04	7.53	—
Total oil production costs	12.45	16.11	13.99
Depletion	27.48	30.24	22.70
Oil production cost and depletion costs	$ 39.93	$ 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, 2013 vs. 2012

	Years Ended December 31, 2013	Years Ended December 31, 2012	Increase (Decrease)
	(In thousands)		
Revenues and other income:			
Oil and gas revenue	$ 851,212	$ 667,951	$ 183,261
Interest income	275	1,108	(833)
Other income	941	3,150	(2,209)
Total revenues and other income	852,428	672,209	180,219
Costs and expenses:			
Oil and gas production	96,791	95,109	1,682
Exploration expenses	230,314	97,712	132,602
General and administrative	158,421	160,027	(1,606)
Depletion and depreciation	222,544	185,707	36,837
Amortization—deferred financing costs	11,054	8,984	2,070
Interest expense	36,811	52,207	(15,396)
Derivatives, net	17,027	31,490	(14,463)
Loss on extinguishment of debt	—	5,342	(5,342)
Other expenses, net	3,512	1,475	2,037
Total costs and expenses	776,474	638,053	138,421
Income (loss) before income taxes	75,954	34,156	41,798
Income tax expense	166,998	101,184	65,814
Net income (loss)	$ (91,044)	$ (67,028)	$ (24,016)

Oil and gas revenue. Oil and gas revenue increased by $183.3 million during the year ended December 31, 2013 as compared to the year ended December 31, 2012, primarily due to an increase in sales volumes. We lifted and sold approximately 7,778 MBbl at an average realized price per barrel of $109.44 in 2013 and approximately 5,905 MBbl at an average realized price per barrel of $113.12 in 2012.

Oil and gas production. Oil and gas production costs increased by $1.7 million during the year ended December 31, 2013 as compared to the year ended December 31, 2012. The change is due to an increase in routine operating expenses offset by a reduction in workover and rig equipment costs. During the year ended December 31, 2013, we incurred workover costs for two water injection wells. During the year ended December 31, 2012 we incurred workover costs related to acid jobs for six producing wells.

Exploration expenses. Exploration expenses increased by $132.6 million during the year ended December 31, 2013, as compared to the year ended December 31, 2012. During the year ended December 31, 2013, we incurred $105.8 million of unsuccessful well and other related costs primarily related to the Cameroon Sipo-1 exploration well; the Ghana Sapele-1 exploration well; and the Ghana Akasa-2A appraisal well and $110.4 million for seismic costs primarily for Mauritania, Ireland, Morocco and new business activities. 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.

General and administrative. General and administrative costs decreased by $1.6 million during the year ended December 31, 2013, as compared to the year ended December 31, 2012. Cash General and administrative costs increased $16.0 million during the year due to an increase in professional fees and compensation and benefits; however, this was partially offset by a $14.4 million decrease in non-cash general and administrative costs associated with our long-term incentive plan.

Depletion and depreciation. Depletion and depreciation increased $36.8 million during the year ended December 31, 2013, as compared with the year ended December 31, 2012, primarily due to depletion related to an increase in production volumes during the year.

Interest expense. Interest expense decreased by $15.4 million during the year ended December 31, 2013, as compared to the year ended December 31, 2012, primarily due to reduced transaction taxes, decreases in our outstanding debt balance and the mark-to-market changes on our interest rate swaps during the year ended December 31, 2013.

Derivatives, net. The decrease in Derivatives, net is due to the change in fair value of the commodity derivative instruments. The change in fair value includes the impact of increases and decreases in the Dated Brent forward curve compared to our executed hedging arrangements and derivatives entered into or settled during each period.

Income tax expense. The Company recognized an income tax provision attributable to earnings of $167.0 million and $101.2 million during 2013 and 2012, respectively. The Company's effective tax rates for 2013 and 2012 were 219.9% and 296.2%, respectively. The large effective tax rates for the periods presented are due to losses incurred in jurisdictions in which we are not subject to taxes and, therefore, do not generate any income tax benefits as well as losses incurred in jurisdictions in which we have valuation allowances against our deferred tax assets and therefore we do not realize any tax benefit on such losses. Income tax expense increased $65.8 million during the year ended December 31, 2013, as compared with December 31, 2012, primarily due to an increase in pre-tax income from our Ghanaian subsidiary.

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	100,652	128,753	(28,101)
General and administrative	157,087	111,235	45,852
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 andapproximately 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 $28.1 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 $45.9 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.

Liquidity and Capital Resources

We are actively engaged in an ongoing process of anticipating and meeting our funding requirements related to exploring for and developing oil and natural gas resources along the Atlantic Margin. We have historically met our funding requirements through cash flows generated from our operating activities and secured funding from issuances of equity and commercial debt facilities to meet our ongoing liquidity requirements. In relation to cash flow generated from our operating activities, if we are unable to resolve issues related to the continuous removal of associated natural gas in large quantities from the Jubilee Field, and the production restraints caused thereby, then the Company's cash flows from operations will be adversely affected. 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 Sources of Capital

Facility

The Company maintains a commercial debt facility, as amended, (the "Facility") with a number of financial institutions, including the International Finance Corporation with a total commitment of $1.5 billion.

As of December 31, 2013, borrowings under the Facility totaled $900.0 million and the undrawn availability under the Facility was $309.5 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 determine 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. The availability period for the revolving-credit facility, as amended in April 2013 expires on December 15, 2014 and the letter of credit sublimit expires on the final maturity date. The available facility amount is subject to borrowing base constraints and, beginning on December 15, 2014, outstanding borrowings will be constrained by an amortization schedule as well. The first required payment could be as early as March 31, 2015, 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. The Facility contains cross default provisions related to the Corporate Revolver and Revolving Credit Facility.

We were in compliance with the financial covenants contained in the Facility as of the September 30, 2013 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 Facility, as amended, 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 $500 million of commitments and 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 Morocco and Cameroon subsidiaries from (i) certain restrictions related to granting of security in those subsidiaries' 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. In April 2013, the availability under the Corporate Revolver was increased from $260.0 million to $300.0 million by additional commitments from existing and new financial institutions. 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, 2013, there were no borrowings outstanding under the Corporate Revolver and the undrawn availability under the Corporate Revolver was $300.0 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 September 30, 2013 (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. The Corporate Revolver contains cross default provisions related to the Facility and the Revolving Credit Facility.

Letter of Credit Facility

In July 2013, we entered into a revolving letter of credit facility agreement ("LC Facility"). The size of the LC Facility is $100.0 million, with additional commitments up to $50.0 million being available if the existing lender increases its commitments or if commitments from new financial institutions are added. The LC Facility provides that we shall maintain cash collateral in an amount equal to at least 75% of all outstanding letters of credit under the LC Facility, provided that during the period of any breach of certain financial covenants, the required cash collateral amount shall increase to 100%. The fees associated with outstanding letters of credit issued will be 0.5% per annum. The LC Facility has an availability period which expires on June 1, 2016. We may voluntarily cancel any commitments available under the LC Facility at any time. As of December 31, 2013, therewere six outstanding letters of credit totaling $42.0 million under the LC Facility. The LC Facility contains cross default provisions related to the Facility and the Corporate Revolver.

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 2014 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.

2014 Capital Program

We estimate we will incur approximately $575.0 million of capital expenditures for the year ending December 31, 2014.This capital expenditure budget consists of:

- approximately $400 million for developmental related expenditures offshore Ghana; and

- approximately $175 million 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, 2013:

	December 31, 2013 (In thousands)
Cash and cash equivalents	$ 598,108
Drawings under the Facility	900,000
Net debt	301,892
Availability under the Facility	$ 309,504
Availability under the Corporate Revolver	300,000
Available borrowings plus cash and cash equivalents	1,207,612

Cash Flows

	Years Ended December 31,		
	2013	2012	2011
	(In thousands)		
Net cash provided by (used in):			
Operating activities	$ 522,404	$ 371,530	$ 364,909
Investing activities	(324,133)	(402,662)	(385,140)
Financing activities	(115,327)	(126,796)	592,908

Operating activities. Net cash provided by operating activities in 2013 was $522.4 million compared with net cash provided by operating activities of $371.5 million in 2012 and $364.9 million in 2011, respectively. The increase in cash provided by operating activities in 2013 when compared to 2012 was primarily due to an increase in oil and gas revenues and a positive change in working capital items. 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.

Investing activities. Net cash used in investing activities in 2013 was $324.1 million compared with $402.7 million and $385.1 million in 2012 and 2011, respectively. The decrease in cash used in investing activities in 2013 when compared to 2012 was primarily attributable to a decrease in expenditures for oil and gas assets. 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. 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 2013 was $115.3 million compared with net cash used in financing activities of $126.8 million in 2012 and net cash provided by financing activities of $592.9 million in 2011. The decrease in cash used in financing activities for 2013 when compared to 2012 was primarily due to a decrease in deferred financing costs. 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.

Contractual Obligations

The following table summarizes by period the payments due for our estimated contractual obligations as of December 31, 2013:

	Payments Due By Year(4)						
	Total	2014	2015	2016	2017	2018	Thereafter
	(In thousands)						
Facility(1)	$900,000	$ —	$346,693	$149,428	$292,768	$111,111	$ —
Interest payments on long-term debt(2)	134,746	47,417	38,001	25,562	22,005	1,761	—
Operating leases	20,718	4,365	3,518	3,158	3,223	3,323	3,131
Atwood Achiever drilling rig contract(3)	652,120	91,035	217,175	217,770	126,140	—	—

(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, 2013. 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, 2013, there were no borrowings under the Corporate Revolver.

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(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) Commitments calculated using a day rate of $595,000 and an estimated rig delivery date of August 1, 2014.

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

In December 2013, we signed a short-term rig share agreement for the drillship "Maersk Discoverer." The Maersk Discoverer is expected to commence drilling operations in the first half of 2014. The rig share agreement covers a period to drill one exploration well in Morocco at a day rate of approximately $0.6 million. The well is expected to take approximately 90 days.

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, 2013
	2014	2015	2016	2017	2018	Thereafter	
	(In thousands, except percentages)						
Variable rate debt:							
Facility(1)	$ —	$346,693	$149,428	$292,768	$111,111	$ —	$ (900,000)
Weighted average interest rate(2)	3.90%	4.35%	5.79%	7.07%	7.71%	—	
Interest rate swaps:							
Notional debt amount(3)	$47,033	$ 16,875	$ 6,250	$ —	$ —	$ —	$ (1,116)
Fixed rate payable	2.22%	2.22%	2.22%	—	—	—	
Variable rate receivable(4)	0.40%	0.74%	1.41%	—	—	—	
Notional debt amount(3)	$47,033	$ 16,872	$ 6,250	$ —	$ —	$ —	$ (1,175)
Fixed rate payable	2.31%	2.31%	2.31%	—	—	—	
Variable rate receivable(4)	0.40%	0.74%	1.41%	—	—	—	
Notional debt amount(3)	$ 1,868	$ —	$ —	$ —	$ —	$ —	$ (6)
Fixed rate payable	0.98%	—	—	—	—	—	
Variable rate receivable(4)	0.35%	—	—	—	—	—	
Notional debt amount(3)	$38,434	$ 23,137	$ —	$ —	$ —	$ —	$ (437)
Fixed rate payable	1.34%	1.34%	—	—	—	—	
Variable rate receivable(4)	0.40%	0.59%	—	—	—	—	

(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, 2013. 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, 2013, there were no borrowings under the Corporate Revolver.

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

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

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

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2013, our material off-balance sheet arrangements and transactions include operating leases and undrawn letters of credit. There are no other transactions, arrangements, or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect Kosmos' liquidity or availability of or requirements for capital resources.

Critical Accounting Policies

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

Revenue Recognition. We use the sales method of accounting for oil and gas revenues. Under this method, we recognize revenues on the volumes sold based on the provisional sales prices. The volumes sold may be more or less than the volumes to which we are entitled based on our ownership interest in the property. These differences result in a condition known in the industry as a production imbalance. A receivable or liability is recognized only to the extent that we have an imbalance on a specific property greater than the expected remaining proved reserves on such property. As of December 31, 2013 and 2012, we had no oil and gas imbalances recorded in our consolidated financial statements.

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

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

Receivables. Our receivables consist of joint interest billings, oil sales and other receivables. For our oil sales receivable, we require a letter of credit to be posted to secure the outstanding receivable. Receivables from joint interest owners are stated at amounts due, net of any allowances for doubtful accounts. We determine our allowance by considering the length of time past due, future net revenues of the debtor's ownership interest in oil and natural gas properties we operate, and the owner's ability to pay its obligation, among other things.

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, 2013 and 2012, we have a valuation allowance to reduce certain deferred tax assets to amounts that are more likely than not to be realized. If our estimates and judgments regarding our ability to realize our deferred tax assets change, the benefits associated with those deferred tax assets may increase or decrease in the period our estimates and judgments change. On a quarterly basis, management evaluates the need for and adequacy of valuation allowances based on the expected realizability of the deferred tax assets and adjusts the amount of such allowances, if necessary.

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

- the status of our operations in the particular taxing jurisdiction including whether we have commenced production from a commercial discovery;
- whether a commercial discovery has resulted in significant proved reserves that have been independently verified;
- the amounts and history of taxable income or losses in a particular jurisdiction;
- projections of future 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 jurisdiction; 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, swaps with calls and purchased puts. 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 transactions settle.

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

We do not expect the adoption of recently issued accounting pronouncements to 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 our policies. In accordance with these policies and guidelines, our management determines the appropriate timing and extent of derivative transactions. See "Item 8. Financial Statements and Supplementary Data —Note 2— Accounting Policies, Note 9—Derivative Financial Information and Note 10—Fair Value Measurements" for a description of the accounting procedures we follow relative to our derivative financial instruments.

The following table reconciles the changes that occurred in fair values of our open derivative contracts during the year ended December 31, 2013:

	Derivative Contracts Assets (Liabilities)		
	Commodities	Interest Rates	Total
		(In thousands)	
Fair value of contracts outstanding as of December 31, 2012	$ (16,603)	$ (5,939)	$ (22,542)
Changes in contract fair value	(24,183)	(437)	(24,620)
Contract maturities	29,769	3,642	33,411
Fair value of contracts outstanding as of December 31, 2013	$ (11,017)	$ (2,734)	$ (13,751)

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, purchased puts and swaps with calls. In regards to our obligations under our various commodity derivative instruments, if our production does not exceed our existing hedged positions, our exposure to our commodity derivative instruments would increase.

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Commodity Price Sensitivity

The following table provides information about our oil derivative financial instruments that were sensitive to changes in oil prices as of December 31, 2013:

Term(1)	Type of Contract	MBbl	Weighted Average Dated Brent Price per Bbl Deferred Premium Receivable/ (Payable)	Swap	Floor	Ceiling	Call	Liability Fair Value at December 31, 2013(2)
2014:								
January—December	Three-way collars	1,500	$ (1.22)	$ —	$85.00	$115.00	$140.00	$ 3,721
January—December	Three-way collars	1,000	—	—	85.00	115.01	140.00	1,294
January—December	Three-way collars	1,000	—	—	88.10	110.00	125.00	2,548
January—December	Three-way collars	1,500	1.15	—	90.00	113.00	135.00	619
January—December	Three-way collars	1,000	—	—	95.00	115.47	130.00	166
2015:								
January—December	Purchased puts	1,730	$ (3.78)	$ —	$85.00	$ —	$ —	$ 1,943
January—December	Swaps with calls	2,000	—	99.00	—	—	115.00	726

(1) In January 2014, we entered into call spread contracts for 1.7 MMBbl from January 2015 through December 2015 in which we sold a call with a strike price of $110.00 per Bbl and we purchased a call with a strike price of $135.00 per Bbl, effectively creating three-way collars using the previously purchased puts that mature during 2015. The call contracts are indexed to Dated Brent prices and have a weighted average deferred premium receivable of $3.35 per Bbl. We also entered into three-way collar contracts for 1.5 MMBbl from January 2015—December 2015 with a floor price of $90.00 per Bbl, a ceiling price of $110.00 per Bbl and a call price of $135.00 per Bbl. The three-way collar contracts are indexed to Dated Brent prices and have a weighted average deferred premium payable of $0.80 per Bbl.

(2) Fair values are based on the average forward Dated Brent oil prices on December 31, 2013 which by year are: 2014—$108.45 and 2015—$102.33. These fair values are subject to changes in the underlying commodity price. The average forward Dated Brent oil prices based on February 18, 2014 market quotes by year are: 2014—$108.27 and 2015—$102.82.

At December 31, 2013, our open commodity derivative instruments were in a net liability position of $11.0 million. As of December 31, 2013, a hypothetical 10% price increase in the commodity futures price curves would decrease future pre-tax earnings by approximately $48.1 million. Similarly, a hypothetical 10% price decrease would increase future pre-tax earnings by approximately $36.1 million.

Interest Rate Derivative Instruments

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

Interest Rate Sensitivity

At December 31, 2013, we had indebtedness outstanding under the Facility of $900.0 million, of which $743.7 million bore interest at floating rates. The interest rate on this indebtedness as of December 31, 2013 was approximately 3.4%. If LIBOR increased 10% at this level of floating rate debt, we would pay an additional $0.1 million in interest expense per year on the Facility. We pay commitment fees on the $309.5 million of undrawn availability and $290.5 million of unavailable commitments under the Facility and on the $300.0 million of undrawn availability under the Corporate Revolver, which are not subject to changes in interest rates.

As of December 31, 2013, the fair market value of our interest rate swaps was a net liability of approximately $2.7 million. If LIBOR increased by 10%, we estimate the liability would decrease to approximately $2.6 million, and if LIBOR decreased by 10%, we estimate the liability would increase to approximately $2.8 million.

Item 8. Financial Statements and Supplementary Data

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2013 and 2012, 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, 2013. 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, 2013 and 2012, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, 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, 2013, based on criteria established in Internal Control—Integrated Framewor issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated February 24, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Dallas, Texas
February 24, 2014

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, 2013, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) (the COSO criteria). Kosmos Energy Ltd.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting appearing in Item 9A. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Kosmos Energy Ltd. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, 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 2012, 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, 2013 of Kosmos Energy Ltd. and our report dated February 24, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Dallas, Texas
February 24, 2014

KOSMOS ENERGY LTD.

CONSOLIDATED BALANCE SHEETS

(In thousands, except share data)

	December 31, 2013	December 31, 2012
Assets		
Current assets:		
Cash and cash equivalents	$ 598.108	$ 515,164
Restricted cash	21,475	21,341
Receivables:		
Joint interest billings	19,930	21,539
Oil sales	281	108,995
Other	1,115	3,682
Inventories	47,424	33,281
Prepaid expenses and other	27,010	10,470
Current deferred tax assets	19,618	34,585
Derivatives	—	1,061
Total current assets	734,961	750,118
Property and equipment:		
Oil and gas properties, net	1,508,062	1,510,312
Other property, net	14,900	15,450
Total property and equipment, net	1,522,962	1,525,762
Other assets:		
Restricted cash	31,500	29,884
Deferred financing costs, net of accumulated amortization of $24,976 and $13,922 at December 31, 2013 and 2012, respectively	40,111	50,214
Long-term deferred tax assets	16,292	10,145
Total assets	$2,345,826	$2,366,123
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable	$ 94,172	$ 128,855
Accrued liabilities	115,212	41,021
Derivatives	9,940	20,377
Total current liabilities	219,324	190,253
Long-term liabilities:		
Long-term debt	900,000	1,000,000
Derivatives	3,811	3,226
Asset retirement obligations	39,596	27,484
Deferred tax liability	170,226	104,137
Other long-term liabilities	20,534	12,117
Total long-term liabilities	1,134,167	1,146,964
Shareholders' equity:		
Preference shares, $0.01 par value; 200,000,000 authorized shares; zero issued at December 31, 2013 and 2012	—	—
Common shares, $0.01 par value; 2,000,000,000 authorized shares; 391,974,287 and 391,423,703 issued at December 31, 2013 and 2012,respectively	3,920	3,914
Additional paid-in capital	1,781,535	1,712,880

Accumulated deficit	(774,220)	(683,176)
Accumulated other comprehensive income	2,158	3,685
Treasury stock, at cost, 4,400,135 and 2,731,941 shares at December 31, 2013 and 2012, respectively	(21,058)	(8,397)
Total shareholders' equity	992,335	1,028,906
Total liabilities and shareholders' equity	$2,345,826	$2,366,123

See accompanying notes.

KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)

	December 31,		
	2013	2012	2011
Revenues and other income:			
Oil and gas revenue	$ 851,212	$ 667,951	$ 666,912
Interest income	275	1,108	9,093
Other income	941	3,150	775
Total revenues and other income	852,428	672,209	676,780
Costs and expenses:			
Oil and gas production	96,791	95,109	83,551
Exploration expenses	230,314	100,652	128,753
General and administrative	158,421	157,087	111,235
Depletion and depreciation	222,544	185,707	140,469
Amortization—deferred financing costs	11,054	8,984	16,193
Interest expense	36,811	52,207	65,749
Derivatives, net	17,027	31,490	11,777
Loss on extinguishment of debt	—	5,342	59,643
Doubtful accounts expense	—	—	(39,782)
Other expenses, net	3,512	1,475	149
Total costs and expenses	776,474	638,053	577,737
Income before income taxes	75,954	34,156	99,043
Income tax expense	166,998	101,184	76,686
Net income (loss)	(91,044)	(67,028)	22,357
Accretion to redemption value of convertible preferred units	—	—	(24,442)
Net loss attributable to common shareholders/unit holders	$ (91,044)	$ (67,028)	$ (2,085)
Net income (loss) per share attributable to common shareholders (the year ended December 31, 2011 represents the period from May 16, 2011 to December 31, 2011) (Note 14):			
Basic	$ (0.24)	$ (0.18)	$ 0.09
Diluted	$ (0.24)	$ (0.18)	$ 0.09
Weighted average number of shares used to compute net income (loss) per share (the year ended December 31, 2011 represents the period from May 16, 2011 to December 31, 2011) (Note 14):			
Basic	376,819	371,847	368,474
Diluted	376,819	371,847	368,607

See accompanying notes.

KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(In thousands)

	Years Ended December 31,		
	2013	**2012**	**2011**
Net income (loss)	$ (91,044)	$ (67,028)	$ 22,357
Other comprehensive income :			
Reclassification adjustments for derivative (gains) losses included in net income (loss)	(1,527)	163	2,934
Income tax benefit	—	1,027	(1,027)
Other comprehensive income (loss)	(1,527)	1,190	1,907
Comprehensive income (loss)	$ (92,571)	$ (65,838)	$ 24,264

See accompanying notes.

KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY/UNIT HOLDINGS EQUITY

(In thousands)

	Common Units		Common Shares		Additional		Accumulated		
							Other		
					Paid-in	Accumulated	Comprehensive	Treasury	
	Units	Amount	Shares	Amount	Capital	Deficit	Income	Stock	Total
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
Equity-based compensation	—	—	—	—	69,101	—	—	—	69,101
Derivatives, net	—	—	—	—	—	—	(1,527)	—	(1,527)
Restricted stock awards and units	—	—	550	6	(6)	—	—	—	—
Restricted stock forfeitures	—	—	—	—	6	—	—	(6)	—
Purchase of treasury stock	—	—	—	—	(446)	—	—	(12,655)	(13,101)
Net loss	—	—	—	—	—	(91,044)	—	—	(91,044)
Balance as of December 31, 2013	—	$ —	391,974	$ 3,920	$1,781,535	$ (774,220)	$ 2,158	$ (21,058)	$ 992,335

See accompanying notes.

KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31, 2013	2012	2011
Operating activities			
Net income (loss)	$ (91,044)	$ (67,028)	$ 22,357
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization	233,598	194,691	156,662
Deferred income taxes	82,380	80,036	56,457
Unsuccessful well costs	107,565	32,229	91,254
Change in fair value of derivatives	23,093	18,465	21,014
Cash settlements on derivatives	(33,411)	(28,594)	(19,203)
Equity-based compensation	69,026	83,423	50,966
Doubtful accounts expense	—	—	(39,782)
Loss on extinguishment of debt	—	5,342	59,643
Other	4,916	7,890	2,953
Changes in assets and liabilities:			
(Increase) decrease in receivables	111,677	176,905	(122,859)
(Increase) decrease in inventories	(16,763)	(7,385)	4,176
(Increase) decrease in prepaid expenses and other	(16,540)	3,443	(635)
Increase (decrease) in accounts payable	(34,683)	(126,401)	89,214
Increase (decrease) in accrued liabilities	82,590	(1,486)	(7,308)
Net cash provided by operating activities	522,404	371,530	364,909
Investing activities			
Oil and gas assets	(317,413)	(368,990)	(478,943)
Other property	(4,970)	(9,994)	(4,303)
Notes receivable	—	—	13,653
Restricted cash	(1,750)	(23,678)	84,453
Net cash used in investing activities	(324,133)	(402,662)	(385,140)
Financing activities			
Borrowings under long-term debt	—	—	1,503,000
Payments on long-term debt	(100,000)	(110,000)	(1,438,000)
Net proceeds from the initial public offering	—	—	580,374
Purchase of treasury stock	(13,101)	(8,378)	—
Deferred financing costs	(2,226)	(8,418)	(52,466)
Net cash provided by (used in) financing activities	(115,327)	(126,796)	592,908
Net increase (decrease) in cash and cash equivalents	82,944	(157,928)	572,677
Cash and cash equivalents at beginning of period	515,164	673,092	100,415
Cash and cash equivalents at end of period	$ 598,108	$ 515,164	$ 673,092
Supplemental cash flow information			
Cash paid for:			
Interest	$ 36,313	$ 41,234	$ 56,845
Income taxes	$ 68,437	$ 22,020	$ 15,550

Non-cash activities:			
Notes receivable applied to FPSO purchase	$ —	$ —	$ (102,783)

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 along the Atlantic Margin. Our assets include existing production and other major development projects offshore Ghana, as well as exploration licenses with significant hydrocarbon potential offshore Ireland, Mauritania, Morocco (including Western Sahara) and Suriname. Kosmos is listed on the New York Stock Exchange and is traded under the ticker symbol KOS.

In May 2011, contemporaneous with Kosmos Energy Ltd.'s initial public offering ("IPO"), the then outstanding 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 recorded accretion on the Convertible Preferred Units of $24.4 million for the year ended December 31, 2011.

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.

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements (Continued)

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, 2013 and 2012, we had $18.6 million and $21.3 million, respectively, in current restricted cash to meet this requirement. In addition, in accordance with certain of our petroleum contracts, we have posted letters of credit related to performance guarantees for our minimum work obligations. These letters of credit are cash collateralized in accounts held by us and as such are classified as restricted cash. Upon completion of the minimum work obligations and/or entering into the next phase of the petroleum contract, the requirement to post letters of credit will be satisfied and the cash collateral will be released. As of December 31, 2013 and 2012, we had $2.9 million and zero, respectively, of current restricted cash and $31.5 million and $29.9 million, respectively, of long-term restricted cash used to cash collateralize performance guarantees related to our petroleum contracts.

Receivables

Our receivables consist of joint interest billings, oil sales and other receivables. For our oil sales receivable, we require a letter of credit to be posted to secure the outstanding receivable. Receivables from joint interest owners are stated at amounts due, net of any allowances for doubtful accounts. We determine our allowance by considering the length of time past due, future net revenues of the debtor's ownership interest in oil and natural gas properties we operate, and the owner's ability to pay its obligation, among other things. We did not have any allowances for doubtful accounts as of December 31, 2013 and 2012.

Inventories

Inventories consisted of $45.8 million and $33.1 million of materials and supplies and $1.6 million and $0.2 million of hydrocarbons as of December 31, 2013 and 2012, 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.

2. Accounting Policies (Continued)

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 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.

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 developed oil and natural gas reserves for the related field.

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

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

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

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements (Continued)

2. Accounting Policies (Continued)

Capitalized Interest

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

Asset Retirement Obligations

The Company accounts for asset retirement obligations as required by ASC 410—Asset Retirement and Environmental Obligations. Under these standards, the fair value of a liability for an asset retirement obligation is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. If a reasonable estimate of fair value cannot be made in the period the asset retirement obligation is incurred, the liability is recognized when a reasonable estimate of fair value can be made. If a tangible long-lived asset with an existing asset retirement obligation is acquired, a liability for that obligation is recognized at the asset's acquisition 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.

Kosmos Energy Finance International's following assets and liabilities are shown on the face of the consolidated balance sheet as of December 31, 2013 and 2012: long-term debt and current and long-term derivatives liabilities. At December 31, 2013, Kosmos Energy Finance International had $38.1 million in cash and cash equivalents, $18.6 million in current restricted cash, $0.2 million in prepaid expenses and other, $34.2 million in deferred financing costs, net; $1.4 million in accrued liabilities and $8.2 million in other long-term liabilities, which are included in the amounts shown on the face of the consolidated balance sheet. At December 31, 2012, Kosmos Energy Finance International had $118.8 million in cash and cash equivalents, $21.3 million in current restricted cash, $0.2 million in prepaid expenses and other, $42.2 million in deferred financing costs, net; $0.5 million in accrued liabilities and $6.6 million in other long-term liabilities, which are included in the amounts shown on the face of the consolidated balance sheet.

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements (Continued)

2. Accounting Policies (Continued)

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

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, swaps with calls and purchased puts. 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 transactions settle. See Note 9—Derivative Financial Instruments.

Estimates of Proved Oil and Natural Gas Reserves

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

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

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements (Continued)

2. Accounting Policies (Continued)

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, 2013 and 2012, 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, 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.

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements (Continued)

2. Accounting Policies (Continued)

Foreign Currency Translation

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

Concentration of Credit Risk

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.

Recent Accounting Standards

We do not expect the adoption of recently issued accounting pronouncements to have a material effect on our consolidated financial statements.

3. 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 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 4—Joint Interest Billings) to 24.07710%. These consolidated financial statements are based on these re-determined tract participations. 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.

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements (Continued)

4. 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.

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).

5. Property and Equipment

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

	December 31, 2013	December 31, 2012
	(In thousands)	
Oil and gas properties:		
Proved properties	$ 801,348	$ 682,276
Unproved properties	524,257	454,391
Support equipment and facilities	710,289	687,835
Total oil and gas properties	2,035,894	1,824,502
Less: accumulated depletion	(527,832)	(314,190)
Oil and gas properties, net	1,508,062	1,510,312
Other property	31,658	27,316
Less: accumulated depreciation	(16,758)	(11,866)
Other property, net	14,900	15,450
Total property and equipment, net	$ 1,522,962	$ 1,525,762

We recorded depletion expense of $213.7 million, $178.6 million and $135.5 million for the years ended December 31, 2013, 2012 and 2011, respectively.

In November 2012, we finalized the assignment of a 50% participating interest in our blocks offshore Suriname, Block 42 and Block 45, to Chevron Global Energy Inc. ("Chevron"). We retain a 50% participating interest in the blocks and remain 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.

5. Property and Equipment (Continued)

In January 2013, we closed on an agreement to acquire an additional 37.5% participating interest in the Essaouira Offshore block from Canamens Energy Morocco SARL, one of our block partners. Government approvals for this acquisition were finalized in November 2013.

In April 2013, we entered into a farm-in agreement with Antrim Energy Inc., whereby we acquired a 75% participating interest and operatorship, covering Licensing Option 11/5 offshore the west coast of Ireland. As part of the agreement, we reimbursed a portion of previously-incurred exploration costs, as well as carry the partner on future 3D seismic costs.

In April 2013, we entered into a farm-in agreement with Europa Oil & Gas (Holdings) plc, whereby we acquired an 85% participating interest and operatorship, covering Licensing Option 11/7 and 11/8 offshore the west coast of Ireland. As part of the agreement, we reimbursed a portion of previously incurred exploration costs, as well as carry the partner on future 3D seismic costs. Contingent upon an election by us and our partner to enter into a subsequent exploration drilling phase on one or both of the blocks, we will also fund 100% of the costs of the first exploration well on each block, subject to an investment cap of $90.0 million and $110.0 million, respectively, on each block.

In August 2013, final government approvals and processes were completed for the acquisition of the additional 18.75% participating interest in the Foum Assaka block in the Agadir Basin offshore Morocco from Pathfinder Hydrocarbon Ventures Limited ("Pathfinder"), a wholly owned subsidiary of Fastnet Oil and Gas Plc ("Fastnet"), one of our block partners.

In October 2013, we entered into three farm-out agreements with BP plc ("BP") covering our three blocks in the Agadir Basin, offshore Morocco. Under the terms of the agreements, BP will acquire a non-operating interest in each of the Essaouira Offshore, Foum Assaka Offshore and Tarhazoute Offshore blocks. BP will fund Kosmos' share of the cost of one exploration well in each of the three blocks, subject to a maximum spend of $120.0 million per well, and pay its proportionate share of any well costs above the maximum spend. In the event a second exploration well is drilled in any block, BP will pay 150% of its share of costs subject to a maximum spend of $120.0 million per well. Upon close of the transaction, BP shall also pay $36.3 million for their share of past costs and $8.9 million for their portion of shared costs incurred from the effective date of the contract through December 31, 2013. Completion of the transactions is subject to customary closing conditions, including Moroccan Government approvals. After completing the transaction, our participating interests will be 30.0%, 29.925% and 30.0% in the Essaouira Offshore, Foum Assaka Offshore and Tarhazoute Offshore blocks, respectively, and we will remain the operator.

In October 2013, we entered into a farm-out agreement with Capricorn Exploration & Development Company Limited, a wholly owned subsidiary of Cairn Energy PLC ("Cairn"), covering the Cap Boujdour Offshore block, offshore Western Sahara. Under the terms of the agreement, Cairn will acquire a 20% non-operated interest in the exploration permits comprising the Cap Boujdour Offshore block. Cairn will pay 150% of its share of costs of a 3D seismic survey capped at $25.0 million and one exploration well capped at $100.0 million. In the event the exploration well is successful, Cairn will pay 200% of its share of costs on two appraisal wells capped at $100.0 million per well. Additionally, Cairn will contribute $12.3 million towards our future costs and, upon close of the transaction, $0.6 million for their share of costs incurred from the effective date of the contract through December 31, 2013. Completion of the transaction is subject to customary closing conditions, including

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements (Continued)

5. Property and Equipment (Continued)

Moroccan Government approvals. After completing the transaction, our participating interest in the Cap Boujdour Offshore block will be 55.0% and we will remain the operator.

6. 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, 2013, 2012 and 2011. The table excludes$78.5 million, $29.6 million and $51.4 million in costs that were capitalized and subsequently expensed during the same year for the years ended December 31, 2013, 2012 and2011, respectively.

	Years Ended December 31,		
	2013	2012	2011
	(In thousands)		
Beginning balance	$ 372,492	$ 267,592	$ 167,511
Additions to capitalized exploratory well costs pending the determination of proved reserves	32,804	107,527	139,949
Reclassification due to determination of proved reserves	—	—	—
Capitalized exploratory well costs charged to expense	(29,130)	(2,627)	(39,868)
Ending balance	$ 376,166	$ 372,492	$ 267,592

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,		
	2013	2012	2011
	(In thousands, except well counts)		
Exploratory well costs capitalized for a period of one year or less	$ 11,426	$ 106,635	$ 132,838
Exploratory well costs capitalized for a period one to two years	229,140	179,933	134,754
Exploratory well costs capitalized for a period three to four years	135,600	85,924	—
Ending balance	$ 376,166	$ 372,492	$ 267,592
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	8	7	3

As of December 31, 2013, 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 andAkasa discoveries in the WCTP Block and the Tweneboa, Enyenra, Ntomme and Wawa discoveries in the DT Block, which are all in Ghana.

6. Suspended Well Costs (Continued)

Effective January 14, 2014, the Ministry of Energy and GNPC entered into a Memorandum of Understanding with Kosmos Energy, on behalf of the WCTP PA Block partners, wherein all parties have settled all matters pertaining to the Notices of Dispute for the Mahogany East PoD, and the Ministry of Energy has approved the Appraisal Programs for the Mahogany, Teak, and Akasa discoveries.

Mahogany—Three appraisal wells have been drilled. Following additional appraisal and evaluation, a decision regarding commerciality of the Mahogany discovery is expected to be made by the WCTP Block partners in 2015. 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-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 2015. 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 2015. 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 performed a drill stem test and gauge installation on the discovery well and drilled one appraisal well, the Akasa-2A. We believe the Akasa-2A appraisal well successfully identified the down dip water contact associated with the Akasa-1 discovery as intended. Should the Akasa discovery progress to a development, the Akasa-2A appraisal well is expected to be utilized in the development as a water injection well. However, since the Akasa-2A appraisal well did not encounter oil or gas reserves sufficient to be utilized as a producing well, accounting rules require that the costs associated with the Akasa-2A appraisal well be impaired. As such, $20.0 million is included in exploration expenses in the accompanying consolidated statement of operations for the year ended December 31, 2013. Following additional appraisal and evaluation, a decision regarding commerciality of the Akasa discovery is expected to be made by the WCTP Block partners in 2015. 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.

Tweneboa, Enyenra and Ntomme ("TEN") Discoveries—In May 2013, the government of Ghana approved the PoD over the TEN discoveries. Development of TEN will include the drilling and completion of up to 24 development wells, half of the wells are designed as producers and the remainder are for water or gas injection to support ultimate field recoveries. The TEN project is expected to deliver first oil in the second half of 2016. The costs associated with the TEN development will remain as unproved property pending the determination of whether the discoveries are associated with proved reserves.

Wawa Discovery—We are currently reprocessing seismic data and plan to acquire a high resolution seismic survey over the discovery area in 2014. Following additional evaluation and potential appraisal activities, a decision regarding commerciality of the Wawa discovery is expected to be made by the DT Block partners in 2015. Within six months of such declaration, a PoD would be prepared and submitted to Ghana's Ministry of Energy, as required under the DT PA.

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements (Continued)

7. Accounts Payable and Accrued Liabilities

Accrued liabilities consisted of the following:

	December 31, 2013	December 31, 2012
	(In thousands)	
Accrued liabilities:		
Accrued exploration, development and production	$ 73,976	$ 20,616
Income taxes	20,379	4,192
Accrued taxes other than income	15,188	11,124
Accrued general and administrative expenses	4,255	5,089
Accrued other	1,414	—
	$ 115,212	$ 41,021

8. Debt

Facility

In March 2011, the Company secured a commercial debt facility (the "Facility") with a total commitment of $2.0 billion 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.

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 to allow the International Finance Corporation to enter the Facility. The terms and conditions of the Facility remained consistent with the original terms and conditions. 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, 2013, we have $34.2 million of net deferred financing costs related to the Facility, which will be amortized over the remaining term of the Facility.

As of December 31, 2013, borrowings under the Facility totaled $900.0 million and the undrawn availability under the Facility was $309.5 million. Interest expense was $21.4 million, $31.6 million and $45.2 million (net of capitalized interest of $13.1 million, $10.3 million and $4.2 million) and commitment fees were $6.0 million, $6.7 million and $8.0 million for the years ended December 31, 2013, 2012 and 2011, respectively.

8. Debt (Continued)

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 $1.7 million, $3.6 million and $3.0 million of additional interest expense, which is included in the Facility interest expense amounts disclosed above, during the years ended December 31, 2013, 2012 and 2011,respectively.

The Facility provides a revolving-credit and letter of credit facility. The availability period for the revolving-credit facility, as amended in April 2013 expires on December 15, 2014 and the letter of credit sublimit expires on the final maturity date. The available facility amount is subject to borrowing base constraints and, beginning on December 15, 2014, outstanding borrowings will be constrained by an amortization schedule. The first required payment could be as early as March 31, 2015, subject to the level of outstanding borrowings and the borrowing base constraints. The Facility has a final maturity date of March 29, 2018. As of December 31, 2013, we had no letters of credit issued under the Facility.

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. The Facility contains cross default provisions related to the Corporate Revolver and Revolving Credit Facility.

We were in compliance with the financial covenants contained in the Facility as of the September 30, 2013 (the most recent assessment date).

Corporate Revolver

In November 2012, we secured a Corporate Revolver from a number of financial institutions. In April 2013, the availability under the Corporate Revolver was increased from $260.0 million to $300.0 million due to additional commitments received from existing and new financial institutions. 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, 2013, we have $5.9 million of net deferred financing costs related to the Corporate Revolver, which will be amortized over the remaining term, or November 20, 2015.

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements (Continued)

8. Debt (Continued)

As of December 31, 2013, there were no borrowings outstanding under the Corporate Revolver and the undrawn availability under the Corporate Revolver was $300.0 million. Commitment fees were $7.0 million and $0.7 million for the years ended December 31, 2013 and 2012, respectively.

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

We were in compliance with the financial covenants contained in the Corporate Revolver as of September 30, 2013 (the most recent assessment date). The Corporate Revolver contains cross default provisions related to the Facility and the Revolving Credit Facility.

Revolving Letter of Credit Facility

In July 2013, we entered into a revolving letter of credit facility agreement ("LC Facility"). The size of the LC Facility is $100.0 million, with additional commitments up to $50.0 million being available if the existing lender increases its commitment or if commitments from new financial institutions are added. The LC Facility provides that we maintain cash collateral in an amount equal to at least 75% of all outstanding letters of credit under the LC Facility, provided that during the period of any breach of certain financial covenants, the required cash collateral amount shall increase to 100%. The fees associated with outstanding letters of credit issued will be 0.5% per annum. The LC Facility has an availability period which expires on June 1, 2016. We may voluntarily cancel any commitments available under the LC Facility at any time. As of December 31, 2013, there were six outstanding letters of credit totaling $42.0 million under the LC Facility. The LC Facility contains cross default provisions related to the Facility and the Corporate Revolver.

At December 31, 2013, the scheduled maturities of debt during the five year period and thereafter are as follows:

	Payments Due by Year					
	2014	2015	2016	2017	2018	Thereafter
	(In thousands)					
Facility(1)	$ —	$ 346,693	$ 149,428	$ 292,768	$ 111,111	$ —

(1) The scheduled maturities of debt are based on the level of borrowings and the estimated future available borrowing base as of December 31, 2013. 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.

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements (Continued)

9. Derivative Financial Instruments

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

We manage market and counterparty credit risk in accordance with our policies. 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 derivative contracts as required by ASC 820—Fair Value Measurements and Disclosures.

Oil Derivative Contracts

The following table sets forth the volumes in barrels underlying the Company's outstanding oil derivative contracts and the weighted average Dated Brent prices per Bbl for those contracts as of December 31, 2013.

			Weighted Average Dated Brent Price per Bbl				
Term(1)	Type of Contract	MBbl	Deferred Premium Receivable/ (Payable)	Swap	Floor	Ceiling	Call
2014:							
January —December	Three-way collars	1,500	$ (1.22)	$ —	$85.00	$115.00	$140.00
January —December	Three-way collars	1,000	—	—	85.00	115.01	140.00
January —December	Three-way collars	1,000	—	—	88.10	110.00	125.00
January —December	Three-way collars	1,500	1.15	—	90.00	113.00	135.00
January —December	Three-way collars	1,000	—	—	95.00	115.47	130.00
2015:							
January —December	Purchased puts	1,730	$ (3.78)	$ —	$85.00	$ —	$ —
January —December	Swaps with calls	2,000	—	99.00	—	—	115.00

(1) In January 2014, we entered into call spread contracts for 1.7 MMBbl from January 2015 through December 2015 in which we sold a call with a strike price of $110.00 per Bbl and we purchased a call with a strike price of $135.00 per Bbl, effectively creating three-way collars using the previously purchased puts that mature during 2015. The call contracts are indexed to Dated Brent prices and have a weighted average deferred premium receivable of $3.35 per Bbl. We also entered into three-way collar contracts for 1.5 MMBbl from January 2015—December 2015 with a floor price of $90.00 per Bbl, a ceiling price of $110.00 per Bbl and a call price of $135.00 per Bbl. The three-way collar contracts are indexed to Dated Brent prices and have a weighted average deferred premium payable of $0.80 per Bbl.

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9. Derivative Financial Instruments (Continued)

Interest Rate Swaps Derivative Contracts

The following table summarizes our open interest rate swaps as of December 31, 2013, whereby we pay a fixed rate of interest and the counterparty pays a variable LIBOR-based rate:

Term	Weighted Average Notional Amount	Weighted Average Fixed Rate	Floating Rate
	(In thousands)		
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, 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. The Company expects to reclassify $1.4 million of gains from AOCI to interest expense within the next 12 months. See Note 10—Fair Value Measurements for additional information regarding the Company's derivative instruments.

The following tables disclose the Company's derivative instruments as of December 31, 2013 and 2012 and gain/(loss) from derivatives during the years ended December 31, 2013, 2012 and 2011:

Type of Contract	Balance Sheet Location	Estimated Fair Value Asset (Liability) December 31, 2013	2012
		(In thousands)	
Derivatives not designated as hedging instruments:			
Derivative assets:			
Commodity(1)	Derivatives assets—current	$ —	$ 1,061
Derivative liabilities:			
Commodity(2)	Derivatives liabilities—current	(7,873)	(17,005)
Interest rate	Derivatives liabilities—current	(2,067)	(3,372)
Commodity(3)	Derivatives liabilities—long-term	(3,144)	(659)
Interest rate	Derivatives liabilities—long-term	(667)	(2,567)
Total derivatives not designated as hedging instruments		$ (13,751)	$ (22,542)

(1) The commodity derivative asset represents our provisional oil sales contract as of December 31, 2012.

(2) Includes zero and $3.4 million, as of December 31, 2013 and 2012, respectively of cash settlements made on our commodity derivative contracts which were settled in the month subsequent to period end. Also, includes net deferred premiums payable of $0.1 million and $7.6 million related to commodity derivative contracts as of December 31, 2013 and 2012, respectively.

KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements (Continued)

9. Derivative Financial Instruments (Continued)

(3) Includes net deferred premiums payable of $6.5 million and $2.4 million related to commodity derivative contracts as of December 31, 2013 and 2012, respectively.

Type of Contract	Location of Gain/ (Loss)	Amount of Gain/(Loss) Years Ended December 31, 2013	2012	2011
		(In thousands)		
Derivatives in cash flow hedging relationships:				
Interest rate(1)	Interest expense	$ 1,527	$ (163)	$ (2,934)
Total derivatives in cash flow hedging relationships		$ 1,527	$ (163)	$ (2,934)
Derivatives not designated as hedging instruments:				
Commodity(2)	Oil and gas revenue	$ (7,156)	$ 15,652	$ 3,246
Commodity	Derivatives, net	(17,027)	(31,490)	(11,777)
Interest rate	Interest expense	(437)	(2,464)	(9,548)
Total derivatives not designated as hedging instruments		$ (24,620)	$ (18,302)	$ (18,079)

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

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

Offsetting of Derivative Assets and Derivative Liabilities

Our derivative instruments subject to master netting arrangements with our counterparties only have the right of offset when there is an event of default. As of December 31, 2013 and 2012, there was not an event of default and, therefore, the associated gross asset or gross liability amounts related to these arrangements are presented on the consolidated balance sheets. Additionally, there were no material rights of offset available, if an event of default occurred, as of December 31, 2013 and 2012.

10. Fair Value Measurements

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

- Level 1—quoted prices for identical assets or liabilities in active markets.

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Notes to Consolidated Financial Statements (Continued)

10. Fair Value Measurements (Continued)

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

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

The following tables present the Company's assets and liabilities that are measured at fair value on a recurring basis as of December 31, 2013 and 2012, 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, 2013				
Liabilities:				
Commodity derivatives	$ —	$ (11,017)	$ —	$ (11,017)
Interest rate derivatives	—	(2,734)	—	(2,734)
Total	$ —	$ (13,751)	$ —	$ (13,751)
December 31, 2012				
Assets:				
Commodity derivatives	$ —	$ 1,061	$ —	$ 1,061
Liabilities:				
Commodity derivatives	—	(17,664)	—	(17,664)
Interest rate derivatives	—	(5,939)	—	(5,939)
Total	$ —	$ (22,542)	$ —	$ (22,542)

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 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, purchased puts and swaps with calls for notional barrels of oil at fixed Dated Brent oil prices. The values attributable to 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

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Notes to Consolidated Financial Statements (Continued)

10. Fair Value Measurements (Continued)

options and was corroborated by market-quoted volatility factors. The deferred premium is included in the fair market value of the commodity derivatives. See Note 9—Derivative Financial Instruments for additional information regarding the Company's derivative instruments.

Provisional Oil Sales

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

Interest Rate Derivatives

We have interest rate swaps, 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.

11. Asset Retirement Obligations

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

	December 31,	
	2013	2012
	(In thousands)	
Asset retirement obligations:		
Beginning asset retirement obligations	$ 27,484	$ 20,670
Liabilities incurred during period	8,558	1,775
Revisions in estimated retirement obligations	—	2,345
Accretion expense	3,554	2,694
Ending asset retirement obligations	$ 39,596	$ 27,484

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

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Notes to Consolidated Financial Statements (Continued)

12. 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 (vested and unvested) 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

Total profit unit compensation expense recognized in income was $1.2 million for the year ended December 31, 2011. 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, 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 rates ranging from 7.0% to 27.0% for employees and none for management.

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Notes to Consolidated Financial Statements (Continued)

12. Equity-based Compensation (Continued)

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. As of December 31, 2013, the Company had approximately 5.3 million shares that remain available for issuance under the LTIP.

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 $69.0 million, $83.4 million and $49.8 million during the years ended December 31, 2013, 2012 and 2011, respectively. The total tax benefit for the years ended December 31, 2013, 2012 and 2011 was $23.5 million, $28.8 million and $17.3 million, respectively. Additionally, we expensed a tax shortfall related to equity-based compensation of $7.0 million, $8.1 million and zero for the years ended December 31, 2013, 2012 and 2011, respectively. 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.

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Notes to Consolidated Financial Statements (Continued)

12. Equity-based Compensation (Continued)

The following table reflects the outstanding restricted stock awards as of December 31, 2013:

	Service Vesting Restricted Stock Awards	Weighted-Average Grant-Date Fair Value	Market / Service Vesting Restricted Stock Awards	Weighted-Average Grant-Date Fair Value
	(In thousands)		(In thousands)	
Outstanding at 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	13.30
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
Granted	351	10.73	—	—
Forfeited	(462)	16.51	(96)	12.35
Vested	(3,403)	17.18	—	—
Outstanding at December 31, 2013	6,384	16.48	3,438	12.95

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Notes to Consolidated Financial Statements (Continued)

12. Equity-based Compensation (Continued)

The following table reflects the outstanding restricted stock units as of December 31, 2013:

	Service Vesting Restricted Stock Units	Weighted-Average Grant-Date Fair Value	Market / Service Vesting Restricted Stock Units	Weighted-Average Grant-Date Fair Value
	(In thousands)		(In thousands)	
Outstanding at 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
Granted	1,591	10.79	1,105	15.44
Forfeited	(133)	10.51	(72)	15.74
Vested	(243)	10.59	—	—
Outstanding at December 31, 2013	2,238	10.74	1,858	15.59

As of December 31, 2013, total equity-based compensation to be recognized on unvested restricted stock awards and restricted stock units is $124.2 million over a weighted average period of 1.65 years.

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 ranged from $15.44 to $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

12. Equity-based Compensation (Continued)

our historical volatility and the historical volatilities of our peer companies and ranged from 53.0% to 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 ranged from 0.5% to 0.7%.

13. 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.

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

	Years Ended December 31,		
	2013	2012	2011
	(In thousands)		
Bermuda	$ (26,492)	$ (11,651)	$ (4,826)
United States	11,872	14,342	8,808
Foreign—other	90,574	31,465	95,061
Income before income taxes	$ 75,954	$ 34,156	$ 99,043

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

	Years Ended December 31,		
	2013	2012	2011
	(In thousands)		
Current:			
Bermuda	$ —	$ —	$ —
United States	14,182	21,148	20,229
Foreign—other	70,436	—	—
Total current	84,618	21,148	20,229
Deferred:			
Bermuda	—	—	—
United States	(2,665)	(7,908)	(16,857)
Foreign—other	85,045	87,944	73,314
Total deferred	82,380	80,036	56,457
Income tax expense	$ 166,998	$ 101,184	$ 76,686

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Notes to Consolidated Financial Statements (Continued)

13. Income Taxes (Continued)

Our reconciliation of income tax expense, as computed by applying our Bermuda statutory rate and the reported effective tax rate, is as follows:

	Years Ended December 31, 2013	2012	2011
	(In thousands)		
Tax at Bermuda statutory rate	$ —	$ —	$ —
Foreign income taxed at different rates	127,301	73,277	52,922
Change in valuation allowance(1)	(4,065)	14,103	19,362
Non-deductible and other items(1)	36,664	5,669	4,402
Tax shortfall on equity-based compensation	7,098	8,135	—
Total tax expense	$ 166,998	$ 101,184	$ 76,686
Effective tax rate(2)	219.9%	296.2%	77.4%

(1) We took all actions required to voluntarily relinquish the Ndian River Block and Fako Block in Cameroon; therefore, the deferred tax asset and its corresponding valuation allowance were written off in 2013. As of December 31, 2012, we had a $40.1 million deferred tax asset and related valuation allowance, which were written off during 2013. The write off of the deferred tax asset and the related valuation allowance does not have an impact on the income tax expense.

(2) The effective tax rate during the years ended December 31, 2013, 2012 and 2011 was also impacted by losses of $178.8 million, $168.5 million and $86.2 million, respectively, incurred in jurisdictions in which we are not subject to taxes and, therefore, do not generate any income tax benefits.

The effective tax rate for the United States is approximately 97% and 92% for the years ended December 31, 2013 and 2012, respectively. The high effective tax rates in the United States are due to the effect of tax shortfalls related to equity-based compensation. The effective tax rate for Ghana is approximately 36% for the years ended December 31, 2013 and 2012. Ourother foreign jurisdictions have a 0% effective tax rate because they reside in countries with a 0% statutory rate, or we have experienced losses in those countries and have a full valuation allowance reserved against the corresponding net deferred tax assets.

Deferred tax assets and liabilities, which are computed on the estimated income tax effect of temporary differences between financial and tax bases in assets and liabilities, are determined using the tax 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

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Notes to Consolidated Financial Statements (Continued)

13. 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, 2013	December 31, 2012
	(In thousands)	
Deferred tax assets:		
Foreign capitalized operating expenses(1)(2)	$ 46,087	$ 38,453
Foreign net operating losses(2)	17,579	41,569
Equity compensation	28,112	26,033
Unrealized derivative losses	10,197	5,714
Other	9,582	11,047
Total deferred tax assets	111,557	122,816
Valuation allowance(2)	(59,540)	(63,605)
Total deferred tax assets, net	52,017	59,211
Deferred tax liabilities:		
Depletion, depreciation and amortization related to property and equipment(1)	(186,333)	(118,618)
Total deferred tax liabilities	(186,333)	(118,618)
Net deferred tax asset (liability)	$ (134,316)	$ (59,407)

(1) As reported in our annual report on Form 10-K for the year ended 2012, a $34.2 million deferred tax asset was netted against the deferred tax liability. We reclassed this amount from the deferred tax liability on depletion, depreciation and amortization related to property and equipment to the deferred tax asset capitalized operating expenses.

(2) We took all actions required to voluntarily relinquish the Ndian River Block and Fako Block in Cameroon; therefore, the deferred tax asset and its corresponding valuation allowance were written off in 2013. As of December 31, 2012, we had a $40.1 million deferred tax asset and related valuation allowance, which were written off during 2013. The write off of the deferred tax asset and the related valuation allowance does not have an impact on the income tax expense.

As of December 31, 2013, our Ghana operations are in a net deferred tax liability position. The Ghana net operating loss carryforward existing as of December 31, 2012 was utilized during 2013.

The Company has recorded a full valuation allowance against the net deferred tax assets in Morocco, Suriname, Ireland and Mauritania. During 2013, we took all actions required to voluntarily relinquish the Ndian River Block and Fako Block in Cameroon and therefore, wrote off the $32.1 million deferred tax asset (and the related valuation allowance) related to the blocks. The net change in the valuation allowance of $(4.1) million includes the $32.1 million write off of the Cameroon valuation allowance, with the remaining change due to additional losses generated in Morocco, Suriname, Ireland and Mauritania.

13. Income Taxes (Continued)

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, if any. The Company currently has recorded deferred tax assets of $27.4 million, recorded at the Moroccan statutory rate of 30%, with an offsetting valuation allowance of $27.4 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.

The Company has foreign net operating loss carryforwards of $52.0 million, which begin to expire in 2014, and $5.8 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 2012 through 2013 and to Texas margin tax examinations for the tax years 2009 through 2013. In addition, the Company is open to income tax examinations for years 2004 through 2013 in its significant other foreign jurisdictions (Ghana, Cameroon and Morocco).

As of December 31, 2013, 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.

14. 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 12—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.

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Notes to Consolidated Financial Statements (Continued)

14. 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, 2013	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	$ (91,044)	$ (67,028)	$ 36,106
Less: Basic income allocable to participating securities(1)	—	—	1,643
Basic net income (loss) allocable to common shareholders	(91,044)	(67,028)	34,463
Diluted adjustments to income allocable to participating securities(1)	—	—	9
Diluted net income (loss) allocable to common shareholders	$ (91,044)	$ (67,028)	$ 34,472
Denominator:			
Weighted average number of shares used to compute net income (loss) per share:			
Basic	376,819	371,847	368,474
Restricted stock awards(1)(2)	—	—	133
Diluted	376,819	371,847	368,607
Net income (loss) per share attributable to common shareholders:			
Basic	$ (0.24)	$ (0.18)	$ 0.09
Diluted	$ (0.24)	$ (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, 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.

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

(2) For the years ended December 31, 2013 and 2012 and for the period from May 16, 2011 through December 31, 2011, we excluded 13.9 million, 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.

15. 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 position; however, an unfavorable outcome could have a material adverse effect on our results from operations for a specific interim period or year.

The Company leases facilities under various operating leases that expire through 2019, including our office space. Rent expense under these agreements, was $4.1 million, $4.3 million and $2.3 million for the years ended December 31, 2013, 2012 and 2011, respectively.

In June 2013, we signed a long-term rig agreement with a subsidiary of Atwood Oceanics, Inc. for the new build drillship "Atwood Achiever." Currently under construction, the rig is expected to commence drilling operations in the second half of 2014. The rig's capabilities include drilling to total depths of up to 40,000 feet (12,200 meters), and in water depths of up to 12,000 feet (3,660 meters). The rig agreement covers an initial period of three years at a day rate of approximately $0.6 million, with an option to extend the agreement for an additional three-year term. The estimated rig delivery date is August 2014.

In December 2013, we signed a short-term rig share agreement for the drillship "Maersk Discoverer." The Maersk Discoverer is expected to commence drilling operations in the first half of 2014. The rig share agreement covers a period to drill one exploration well offshore Morocco at a day rate of approximately $0.6 million. The well is expected to take approximately 90 days.

Future minimum rental commitments under these leases at December 31, 2013, are as follows:

	Payments Due By Year(1)						
	Total	2014	2015	2016	2017	2018	Thereafter
	(In thousands)						
Operating leases	$ 20,718	$ 4,365	$ 3,518	$ 3,158	$ 3,223	$ 3,323	$ 3,131
Atwood Achiever drilling rig contract (2)	$ 652,120	$ 91,035	$ 217,175	$ 217,770	$ 126,140	$ —	$ —

(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.

(2) Commitments calculated using a day rate of $595,000 and an estimated rig delivery date of August 1, 2014.

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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. 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 developed and undeveloped reserves at December 31, 2010	52	22	56
Extensions and discoveries	—	—	—
Production	(6)	(2)	(6)
Revision in estimate(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)
Revision in estimate(3)	1	(14)	(2)
Purchases of minerals-in-place	—	—	—
Net proved developed and undeveloped reserves at December 31, 2012	42	9	43
Extensions and discoveries	—	—	—
Production	(8)	(1)	(8)
Revision in estimate(4)	11	3	12
Purchases of minerals-in-place	—	—	—
Net proved developed and undeveloped reserves at December 31, 2013(2)	45	11	47
Proved developed reserves(2)			
December 31, 2011	23	16	26
December 31, 2012	32	9	33
December 31, 2013	36	10	38
Proved undeveloped reserves(2)			
December 31, 2011	25	8	26
December 31, 2012	10	1	10
December 31, 2013	9	1	9

(1) The increase in estimated oil reserves is due to an increase in our Jubilee Field unit interest (see Note 3—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.

(4) The increase in proved reserves is a result of drilling and reservoir performance.

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 2013. The average 2013 Brent crude price of $108.02 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 $0.74 per barrel; therefore, the adjusted oil price is $108.76 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, 2013			
Unproved properties	$ 492,065	$ 32,192	$ 524,257
Proved properties	1,511,637	—	1,511,637
	2,003,702	32,192	2,035,894
Accumulated depletion, depreciation and amortization	(527,832)	—	(527,832)
Net capitalized costs	$ 1,475,870	$ 32,192	$ 1,508,062
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

(1) Includes Africa, excluding Ghana, Europe 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, 2013			
Property acquisition:			
Unproved	$ —	$ 13,787	$ 13,787
Proved	—	—	—
Exploration	183,635	183,213	366,848
Development	61,071	—	61,071
Total costs incurred	$ 244,706	$ 197,000	$ 441,706
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

(1) Includes Africa, excluding Ghana, Europe 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 2013. The average 2013 Brent crude price of $108.02 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 $0.74 per barrel; therefore, the adjusted oil price is $108.76 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.

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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, 2013	
Future cash inflows	$ 4,921
Future production costs	(617)
Future development costs	(300)
Future Ghanaian tax expenses(1)	(1,168)
Future net cash flows	2,836
10% annual discount for estimated timing of cash flows	(599)
Standardized measure of discounted future net cash flows	$ 2,237
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

(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, 2013, 2012 and 2011, respectively, only reflect the effects of future Ghanaian tax expenselevied under the WCTP and DT PAs.

Changes in the Standardized Measure for Discounted Cash Flows

	Ghana
	(In millions)
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
Sales and Transfers 2013	(754)
Net changes in prices and costs	(95)
Previously estimated development costs incurred during the period	123
Net changes in development costs	53
Revisions of previous quantity estimates	804
Changes in production timing	(41)
Net changes in Ghanaian tax expenses(1)	(32)
Accretion of discount	289
Changes in timing and other	(182)
Balance at December 31, 2013	$ 2,237

(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, 2013, 2012and 2011, respectively, only reflect the effects of future Ghanaian tax expenselevied under the WCTP and DT PAs.

(2) Relates to an increase in our Jubilee Field unit interest (see Note 3—Jubilee Field Unitization).

KOSMOS ENERGY LTD.

Supplemental Quarterly Financial Information (Unaudited)

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
	(In thousands, except per share data)			
2013				
Revenues	$ 228,390	$ 193,778	$ 215,379	$ 214,881
Expenses	164,205	218,341	225,643	168,285
Net income (loss)	20,094	(70,816)	(44,488)	4,166
Net income (loss) attributable to common shareholders	20,094	(70,816)	(44,488)	4,166
Net income (loss) attributable to common shareholders per share:				
Basic(1)	0.05	(0.19)	(0.12)	0.01
Diluted(1)	0.05	(0.19)	(0.12)	0.01
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(1)	(0.10)	(0.07)	(0.10)	0.08
Diluted(1)	(0.10)	(0.07)	(0.10)	0.08

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

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) was performed under the supervision and with the participation of the Company's management, including our Chief Executive Officer and Chief Financial Officer. This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the SEC reports we file or submit under the Exchange Act is accurate, complete and timely. However, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. The design of a control system must reflect the fact that there are resource constraints, and the benefit of controls must be considered relative to their costs. Consequently, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. Based upon this evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2013, 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 (1992)" 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, 2013 which is included in "Item 8. Financial Statements and Supplementary Data."

Item 9B. Other Information

While the Kyoto Protocol was set to expire in 2012, it has been extended by amendment until 2020 with the understanding among the parties that a new climate change regime will be negotiated by 2015 and succeed the Kyoto Protocol in 2020. Ireland is also a party to the European Union Emissions Trading Scheme that seeks, among other things, to meet the European Union's commitments under the Kyoto Protocol through a "cap and trade" GHG emissions framework.

Disclosures Required Pursuant to Section 13(r) of the Securities Exchange Act of 1934

Under the Iran Threat Reduction and Syria Human Rights Act of 2012, which added Section 13(r) of the Exchange Act, we are required to include certain disclosures in our periodic reports if we or any of our "affiliates" (as defined in Rule 12b-2 under the Exchange Act) knowingly engaged in certain specified activities during the period covered by the report. Because the Securities and Exchange Commission ("SEC") defines the term "affiliate" broadly, it includes any entity controlled by us as well as any person or entity that controls us or is under common control with us ("control" is also construed broadly by the SEC).

We are not presently aware that we and our consolidated subsidiaries have knowingly engaged in any transaction or dealing reportable under Section 13(r) of the Exchange Act during the fiscal quarter ended December 31, 2013. In addition, except as described below, at the time of filing this annual report on Form 10-K, we are not aware of any such reportable transactions or dealings by companies that may be considered our affiliates as to whether they have knowingly engaged in any such reportable transactions or dealings during such period. Upon the filing of periodic reports by such other companies for the fiscal quarter or fiscal year ended December 31, 2013, as the case may be, additional reportable transactions may be disclosed by such companies.

As of December 31, 2013, funds affiliated with The Blackstone Group ("Blackstone") held approximately 29% of our outstanding common shares, and funds affiliated with Warburg Pincus ("Warburg Pincus") held approximately 36% of our outstanding common shares. We are also a party to a shareholders agreement with Blackstone and Warburg Pincus pursuant to which, among other things, Blackstone and Warburg Pincus each currently have the right to designate three members of our board of directors. Accordingly, each of Blackstone and Warburg Pincus may be deemed an "affiliate" of us, both currently and during the fiscal quarter ended December 31, 2013.

Disclosure relating to Blackstone and its affiliates

Blackstone informed us of the information reproduced below (the "Travelport Disclosure") regarding Travelport Limited ("Travelport"), a company that may be considered one of Blackstone's affiliates. Because both we and Travelport may be deemed to be controlled by Blackstone, we may be considered an "affiliate" of Travelport for the purposes of Section 13(r) of the Exchange Act.

Travelport Disclosure:

Quarter ended September 30, 2013

"As part of our global business in the travel industry, we provide certain passenger travel related GDS and Airline IT Solutions services to Iran Air. We also provide certain Airline IT Solutions services to Iran Air Tours. All of these services are either exempt from applicable sanctions prohibitions pursuant to a statutory exemption in the International Emergency Economic Powers Act permitting transactions ordinarily incident to travel or, to the extent not otherwise exempt, specifically licensed by the U.S. Office of Foreign Assets Control ("OFAC"). Subject to any changes in the exempt/licensed status of such activities, we intend to continue these business activities, which are directly related to and promote the arrangement of travel for individuals.

The gross revenue and net profit attributable to these activities in the quarter ended September 30, 2013 were approximately $164,000 and $122,000, respectively."

Quarter ended December 31, 2013

"As part of our global business in the travel industry, we provide certain passenger travel-related GDS and airline IT services to Iran Air. We also provide certain airline IT services to Iran Air Tours. All of these services are either exempt from applicable sanctions prohibitions pursuant to a statutory exemption permitting transactions ordinarily incident to travel or, to the extent not otherwise exempt, specifically licensed by the U.S. Office of Foreign Assets Control. Subject to any changes in the exempt/licensed status of such activities, we intend to continue these business activities, which are directly related to and promote the arrangement of travel for individuals."

The Travelport Disclosure relates solely to activities conducted by Travelport and do not relate to any activities conducted by us. We have no involvement in or control over the activities of Travelport, any of its predecessor companies or any of its subsidiaries. Other than as described above, we have no knowledge of the activities of Travelport with respect to transactions with Iran, and we have not participated in the preparation of the Travelport Disclosure. We have not independently verified the Travelport Disclosure, are not representing to the accuracy or completeness of the Travelport Disclosure and undertake no obligation to correct or update the Travelport Disclosure.

Disclosure relating to Warburg Pincus and its affiliates

Warburg Pincus informed us of the information reproduced below (the "EIG Disclosure") regarding Endurance International Group ("EIG"), a company that may be considered one of Warburg Pincus's affiliates. Because both we and EIG may be deemed to be controlled by Warburg Pincus, we may be considered an "affiliate" of EIG for the purposes of Section 13(r) of the Exchange Act.

EIG Disclosure:

Quarter ended December 31, 2013

"Our business activities are subject to various restrictions under U.S. export controls and trade and economic sanctions laws, including the U.S. Commerce Department's Export Administration Regulations and economic and trade sanctions regulations maintained by the U.S. Treasury Department's Office of Foreign Assets Control, or OFAC. If we fail to comply with these laws and regulations, we could be subject to civil or criminal penalties and reputational harm. In addition, if our third-party resellers fail to comply with these laws and regulations in their dealings, we could face potential liability or penalties for violations. Furthermore, U.S. export control laws and economic sanctions laws prohibit certain transactions with U.S. embargoed or sanctioned countries, governments, persons and entities.

Although we take precautions to prevent transactions with U.S. sanctions targets, we have in the past identified limited instances of non-compliance with these rules and believe we have taken appropriate corrective actions in such instances. For example, on May 1, 2013, during a routine compliance scan of our new and existing subscriber accounts, we discovered a new subscriber account that was created on April 6, 2013 with information matching ORT France, identified by OFAC as a Specially Designated National, or SDN, under the Global Terrorism Sanctions Regulations, 31 C.F.R. Part 594. We had charged the subscriber $114.10 for web hosting and domain name registration services at the time the account was opened and without knowledge of any SDN issue. Upon discovery of the potential SDN match, we promptly suspended the subscriber account, deactivated the website, locked the domain name to prevent it from being transferred and ceased providing services to the subscriber. We also promptly reported the potential SDN match to OFAC. To date, we have not received any correspondence from OFAC regarding the matter.

Although we have implemented compliance measures that are designed to prevent transactions with U.S. sanction targets, there is risk that in the future we or our resellers could provide our solutions or services to such targets despite such compliance measures. This could result in negative consequences to us, including government investigations, penalties and reputational harm.

Changes in our solutions or changes in export and import regulations may create delays in the introduction and sale of our solutions in international markets, prevent our subscribers with international operations from deploying our solutions or, in some cases, prevent the export or import of our solutions to certain countries, governments or persons altogether. Any change in export or import regulations, shift in the enforcement or scope of existing regulations, or change in the countries, governments, persons or technologies targeted by such regulations, could result in decreased use of our solutions or decreased ability to export or sell our solutions to existing or potential subscribers with international operations. Any decreased use of our solutions or limitation on our ability to export or sell our solutions could adversely affect our business, financial condition and operating results."

The EIG Disclosure relates solely to activities conducted by EIG and do not relate to any activities conducted by us. We have no involvement in or control over the activities of EIG, any of its predecessor companies or any of its subsidiaries. Other than as described above, we have no knowledge of the activities of EIG with respect to transactions with Iran, and we have not participated in the preparation of the EIG Disclosure. We have not independently verified the EIG Disclosure, are not representing to the accuracy or completeness of the EIG Disclosure and undertake no obligation to correct or update the EIG Disclosure.

Warburg Pincus informed us of the information reproduced below (the "SAMIH Disclosure") regarding Santander Asset Management Investment Holdings Limited, ("SAMIH"), a company that may be considered one of Warburg Pincus's affiliates. Because both we and SAMIH may be deemed to be controlled by Warburg Pincus, we may be considered an "affiliate" of SAMIH for the purposes of Section 13(r) of the Exchange Act.

SAMIH Disclosure:

Quarter ended December 31, 2013

"Warburg Pincus understands that SAMIH's affiliates intend to disclose in their next annual or quarterly SEC report that an Iranian national, resident in the U.K., who is currently designated by the U.S. and the U.K. under the Iran Sanctions regime, holds two investment accounts with Santander Asset Management UK Limited, a subsidiary of SAMIH and part of the Banco Santander group. The accounts have remained frozen throughout 2013. The investment returns are being automatically reinvested, and no disbursements have been made to the customer. Total revenue in connection with the investment accounts in 2013 was £247 and net profits in 2013 were negligible relative to the overall profits of Banco Santander, S.A."

The SAMIH Disclosure relates solely to activities conducted by SAMIH and do not relate to any activities conducted by us. We have no involvement in or control over the activities of SAMIH, any of its predecessor companies or any of its subsidiaries. Other than as described above, we have no knowledge of the activities of SAMIH with respect to transactions with Iran, and we have not participated in the preparation of the SAMIH Disclosure. We have not independently verified the SAMIH Disclosure, are not representing to the accuracy or completeness of the SAMIH Disclosure and undertake no obligation to correct or update the SAMIH Disclosure.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated herein by reference to the 2014 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2013.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2014 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2013.

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

The information required by this item is incorporated herein by reference to the 2014 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2013.

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

The information required by this item is incorporated herein by reference to the 2014 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2013.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the 2014 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2013.

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 2013, 2012 and 2011 (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.

KOSMOS ENERGY LTD.

CONDENSED PARENT COMPANY BALANCE SHEETS

(In thousands, except share data)

	December 31,	
	2013	2012
Assets		
Current assets:		
Cash and cash equivalents	$ 35,092	$ 132,574
Receivables from subsidiaries	—	373
Prepaid expenses and other	524	375
Total current assets	35,616	133,322
Investment in subsidiaries at equity	955,460	888,473
Deferred financing costs, net of accumulated amortization of $3,300 and $283, respectively	5,950	7,992
Total assets	$ 997,026	$ 1,029,787
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable	$ 35	$ —
Accounts payable to subsidiaries	3,761	—
Accrued liabilities	895	881
Total current liabilities	4,691	881
Shareholders' equity:		
Preference shares, $0.01 par value; 200,000,000 authorized shares; zero issued at December 31, 2013 and 2012	—	—
Common shares, $0.01 par value; 2,000,000,000 authorized shares; 391,974,287 and 391,423,703 issued at December 31, 2013 and 2012,respectively	3,920	3,914
Additional paid-in capital	1,781,535	1,712,880
Accumulated deficit	(774,220)	(683,176)
Accumulated other comprehensive income	2,158	3,685
Treasury stock, at cost, 4,400,135 and 2,731,941 shares at December 31, 2013 and 2012, respectively	(21,058)	(8,397)
Total shareholders' equity	992,335	1,028,906
Total liabilities and shareholders' equity	$ 997,026	$ 1,029,787

KOSMOS ENERGY LTD.

CONDENSED PARENT COMPANY STATEMENTS OF OPERATIONS

(In thousands)

	December 31,		
	2013	2012	2011
Revenues and other income:			
Oil and gas revenue	$ —	$ —	$ —
Interest income	59	400	248
Total revenues and other income	59	400	248
Costs and expenses:			
General and administrative	84,306	93,472	54,442
General and administrative recoveries—related party	(67,865)	(82,370)	(49,378)
Amortization—deferred financing costs	3,017	283	—
Interest expense	7,039	659	—
Other expenses, net	54	6	10
Equity in (earnings) losses of subsidiaries	64,552	55,378	(27,183)
Total costs and expenses	91,103	67,428	(22,109)
Income (loss) before income taxes	(91,044)	(67,028)	22,357
Income tax expense	—	—	—
Net income (loss)	$ (91,044)	$ (67,028)	$ 22,357

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KOSMOS ENERGY LTD.

CONDENSED PARENT COMPANY STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31,		
	2013	2012	2011
Operating activities			
Net income (loss)	$ (91,044)	$ (67,028)	$ 22,357
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Equity in (earnings) losses of subsidiaries	64,552	55,378	(27,183)
Equity-based compensation	69,101	83,423	50,966
Amortization	3,017	283	—
Changes in assets and liabilities:			
(Increase) decrease in prepaid expenses and other	(149)	19	(394)
(Increase) decrease due to/from related party	4,134	(1,531)	1,158
Increase in accounts payable and accrued liabilities	794	136	—
Net cash provided by operating activities	50,405	70,680	46,904
Investing activities			
Investment in subsidiaries	(133,066)	(275,070)	(274,406)
Net cash used in investing activities	(133,066)	(275,070)	(274,406)
Financing activities			
Net proceeds from the initial public offering	—	—	580,374
Purchase of treasury stock	(13,101)	(8,378)	—
Deferred financing costs	(1,720)	(7,530)	—
Net cash provided by financing activities	(14,821)	(15,908)	580,374
Net increase (decrease) in cash and cash equivalents	(97,482)	(220,298)	352,872
Cash and cash equivalents at beginning of period	132,574	352,872	—
Cash and cash equivalents at end of period	$ 35,092	$ 132,574	$ 352,872

Schedule II

Kosmos Energy Ltd.

Valuation and Qualifying Accounts

For the Years Ended December 31, 2013, 2012 and 2011

Description	Balance January 1,	Additions: Charged to Costs and Expenses	Additions: Charged To Other Accounts	Deductions From Reserves	Balance December 31,
2013					
Allowance for doubtful receivables	$ —	$ —	$ —	$ —	$ —
Allowance for deferred tax asset	$ 63,605	$ 28,040	$ —	$ 32,105	$ 59,540
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

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 24, 2014

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 24, 2014
/s/ W. GREG DUNLEVY W. Greg Dunlevy	Chief Financial Officer and Executive Vice President (Principal Financial Officer)	February 24, 2014
/s/ PAUL M. NOBEL Paul M. Nobel	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 24, 2014
/s/ JOHN R. KEMP John R. Kemp	Chairman of the Board of Directors	February 24, 2014
/s/ SIR RICHARD B. DEARLOVE Sir Richard B. Dearlove	Director	February 24, 2014
/s/ DAVID I. FOLEY David I. Foley	Director	February 24, 2014
/s/ DAVID B. KRIEGER David B. Krieger	Director	February 24, 2014

Signature	Title	Date
/s/ JOSEPH P. LANDY Joseph P. Landy	Director	February 24, 2014
/s/ PRAKASH A. MELWANI Prakash A. Melwani	Director	February 24, 2014
/s/ ADEBAYO O. OGUNLESI Adebayo O. Ogunlesi	Director	February 24, 2014
/s/ LARS H. THUNELL Lars H. Thunell	Director	February 24, 2014
/s/ CHRIS TONG Chris Tong	Director	February 24, 2014
/s/ CHRISTOPHER A. WRIGHT Christopher A. Wright	Director	February 24, 2014

INDEX OF EXHIBITS

Exhibit Number	Description of Document
	Governing Documents
3.1	Certificate of Incorporation of the Company (filed as Exhibit 3.1 to the Company's 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).
	Operating Agreements
	Ghana
10.1	Petroleum Agreement in respect of West Cape Three Points Block Offshore Ghana dated July 22, 2004 among the GNPC, Kosmos Ghana and the E.O. Group (filed as Exhibit 10.1 to the Company's Registration Statement on Form S-1/A filed March 3, 2011 (File No. 333-171700), and incorporated herein by reference).
10.2	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	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).
	Cameroon
10.8	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).
	Morocco
10.9	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).
10.10	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).
10.11	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).
10.12	Petroleum Agreement Regarding the Exploration for Exploitation of Hydrocarbons among Office National Des Hydrocarbures Et Des Mines acting on behalf of the Kingdom of Morocco, Kosmos Energy Deepwater Morocco and Canamens Energy Morocco SARL in the area of interest named "Essaouira Offshore" dated September 9, 2011 (filed as Exhibit 10.12 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.13	Deed of Assignment in Petroleum Agreement for the Exploration for and Exploitation of Hydrocarbons in the zone of interest named "Essaouira Offshore" between Canamens Energy Morocco SARL and Kosmos Energy Deepwater Morocco dated December 19, 2012 (filed as Exhibit 10.13 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.14	Petroleum Agreement Regarding the Exploration for Exploitation of Hydrocarbons among Office National Des Hydrocarbures Et Des Mines acting on behalf of the Kingdom of Morocco, Kosmos Energy Deepwater Morocco and Pathfinder Hydrocarbon Ventures Limited in the area of interest named "Foum Assaka Offshore" dated May 4, 2011 (filed as Exhibit 10.14 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).

Exhibit Number	Description of Document
10.15	Deed of Assignment in Petroleum Agreement for the Exploration for and Exploitation of Hydrocarbons in the zone of interest named "Foum Assaka Offshore" between Pathfinder Hydrocarbon Ventures Limited and Kosmos Energy Deepwater Morocco dated June 11, 2012 (filed as Exhibit 10.15 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.16	Petroleum Agreement Regarding the Exploration for Exploitation of Hydrocarbons among Office National Des Hydrocarbures Et Des Mines acting on behalf of the Kingdom of Morocco and Kosmos Energy Deepwater Morocco in the area of interest named "Tarhazoute Offshore" dated October 10, 2013 (filed as Exhibit 10.16 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.17	Petroleum Agreement Regarding the Exploration for Exploitation of Hydrocarbons between Office National Des Hydrocarbures Et Des Mines acting on behalf of the State and Kosmos Energy Offshore Morocco HC in the area of interest named "Cap Boujdour Offshore" dated July 7, 2011 (filed as Exhibit 10.27 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
	Suriname
10.18	Production Sharing Contract for Petroleum Exploration, Development and Production relating to Block 42 Offshore Suriname between Staatsolie Maatshappij Suriname N.V. and Kosmos Energy Suriname dated December 13, 2011 (filed as Exhibit 10.20 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.19	Production Sharing Contract for Petroleum Exploration, Development and Production relating to Block 45 Offshore Suriname between Staatsolie Maatshappij Suriname N.V. and Kosmos Energy Suriname dated December 13, 2011 (filed as Exhibit 10.21 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.20	Deed of Assignment and Transfer relating to Blocks 42 and 45 Offshore Suriname between Kosmos Energy Suriname and Chevron Suriname Exploration Limited dated May 31, 2012 (filed as Exhibit 10.22 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
	Mauritania
10.21	Exploration and Production Contract between The Islamic Republic of Mauritania and Kosmos Energy Mauritania (Bloc C8) dated April 5, 2012 (filed as Exhibit 10.17 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.22	Exploration and Production Contract between The Islamic Republic of Mauritania and Kosmos Energy Mauritania (Bloc C12) dated April 5, 2012 (filed as Exhibit 10.18 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).

Exhibit Number	Description of Document
10.23	Exploration and Production Contract between The Islamic Republic of Mauritania and Kosmos Energy Mauritania (Bloc C13) dated April 5, 2012 (filed as Exhibit 10.19 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
	Ireland
10.24	Irish Continental Shelf—Petroleum Exploration License No. 1/13 (Frontier) between the Minister for Communications, Energy and Natural Resources, Ireland, and Kosmos Energy Ireland and Antrim Exploration (Ireland) Ltd dated August 28, 2013 (filed as Exhibit 10.23 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.25	Irish Continental Shelf—Petroleum Exploration License No. 2/13 (Frontier) between the Minister for Communications, Energy and Natural Resources, Ireland, and Kosmos Energy Ireland and Europa Oil and Gas (Holdings) Plc. dated August 23, 2013 (filed as Exhibit 10.24 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.26	Irish Continental Shelf—Petroleum Exploration License No. 3/13 (Frontier) between the Minister for Communications, Energy and Natural Resources, Ireland, and Kosmos Energy Ireland and Europa Oil and Gas (Holdings) Plc. dated August 23, 2013 (filed as Exhibit 10.25 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.27	Licensing Terms for Offshore Oil and Gas Exploration, Development and Production 2007, relating to the Petroleum Exploration Licenses No. 1/13, No. 2/13 and No. 3/13 offshore Ireland (filed as Exhibit 10.26 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
	Drilling Rigs
10.28	Deepwater Drilling Unit Contract Agreement, dated as of June 9, 2013, between Kosmos Energy Ventures and Alpha Offshore Drilling Services Company (filed as Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013, and incorporated herein by reference).
	Financing Agreements
10.29	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).
10.30	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).

Exhibit Number	Description of Document
10.31	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).
10.32	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).
10.33	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 (filed as Exhibit 10.28 to the Company's Annual Report on Form 10-K for the year ended December 31, 2012, and incorporated herein by reference).
10.34	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 (filed as Exhibit 10.29 to the Company's Annual Report on Form 10-K for the year ended December 31, 2012, and incorporated herein by reference).
10.35	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 (filed as Exhibit 10.30 to the Company's Annual Report on Form 10-K for the year ended December 31, 2012, and incorporated herein by reference).
10.36	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 (filed as Exhibit 10.31 to the Company's Annual Report on Form 10-K for the year ended December 31, 2012, and incorporated herein by reference).
10.37	Multi-Currency Revolving Letter of Credit Facility Agreement , dated as of July 3, 2013 and amended and restated on July 29, 2013, among Kosmos Energy Credit International, as the Original Borrower, Kosmos Energy Ltd., as the Original Guarantor, and Societe Generale, London Branch, as the Original Lender, Facility Agent, Security Agent and Account Bank (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013, and incorporated herein by reference).

Exhibit Number	Description of Document
10.38	Charge on Cash Deposits and Account Bank Agreement, dated as of July 3, 2013, among Kosmos Energy Credit International and Societe Generale, London Branch, as Security Agent and Account Bank (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013, and incorporated herein by reference).
10.39	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).
	Agreements with Shareholders and Directors
10.40	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).
10.41	Shareholders Agreement, dated as of May 10, 2011, among Kosmos Energy Ltd. and the other parties signatory thereto (filed as Exhibit 9.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2012, and incorporated herein by reference).
10.42	Registration Rights Agreement, dated as of October 7, 2009, among Kosmos Energy Holdings and the other parties signatory thereto (filed as Exhibit 10.32 to the Company's Annual Report on Form 10-K for the year ended December 31, 2012, and incorporated herein by reference).
10.43	Joinder Agreement to the Registration Rights Agreement, dated as of May 10, 2011, among Kosmos Energy Ltd. and the other parties signatory thereto (filed as Exhibit 10.33 to the Company's Annual Report on Form 10-K for the year ended December 31, 2012, and incorporated herein by reference).
10.44	Amendment No. 1 to the Registration Rights Agreement, dated as of February 8, 2013, among Kosmos Energy Ltd. and the other parties signatory thereto (filed as Exhibit 10.34 to the Company's Annual Report on Form 10-K for the year ended December 31, 2012, and incorporated herein by reference).
	Management Contracts/Compensatory Plans or Arrangements
10.45†	Form of Long Term Incentive Plan (filed as Exhibit 99.1 to the Company's Registration Statement on Form S-8 filed May 16, 2011 (File No. 333-174234), and incorporated herein by reference).
10.46†	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).
10.47†	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).
10.48†	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).
10.49†	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
10.50†	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).
10.51†	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).
10.52†	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).
10.53†	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).
10.54†	Letter of Resignation from John R. Kemp III, dated as of July 18, 2013 (filed as Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.55†	Offer Letter, dated November 22, 2011, between Kosmos Energy, LLC and Darrell McKenna (filed as Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.56†	Offer Letter, dated March 2, 2012, between Kosmos Energy, LLC and Tyner Gaston (filed as Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.57†	Offer Letter, dated May 16, 2012, between Kosmos Energy, LLC and Paul Nobel (filed as Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.58† *	Offer Letter, dated January 10, 2014, between Kosmos Energy, LLC and Andrew Inglis.
10.59†	Form of RSU Award Agreement (Directors—Service-Vesting) (filed as Exhibit 10.9 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.60†	Form of RSU Award Agreement (Employees—Service-Vesting) (filed as Exhibit 10.10 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.61†	Form of RSU Award Agreement (Employees—Performance-Vesting) (filed as Exhibit 10.11 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.62†	Consulting Agreement dated October 31, 2011 between Kosmos Energy Ltd. and John R. Kemp III (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).
10.63†	Amendment No. 1 to Consulting Agreement dated February 23, 2012 between Kosmos Energy Ltd. and

John R. Kemp III (filed as Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2012, and incorporated herein by reference).

Exhibit Number	Description of Document
10.64†	Amendment No. 2, effective as of January 1, 2013, to Consulting Agreement between Kosmos Energy Ltd. and John R. Kemp III (filed as Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference)
10.65†	Amendment No. 3, effective as of October 1, 2013, to Consulting Agreement between Kosmos Energy Ltd. and John R. Kemp III (filed as Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, and incorporated herein by reference).
10.66† *	Kosmos Energy Ltd. Change in Control Severance Policy for U.S. Employees, dated December 19, 2013.
	Other Exhibits
14.1	Code of Business Conduct and Ethics (filed as Exhibit 14.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2011, and incorporated herein by reference).
21.1*	List of Subsidiaries.
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of 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.
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.

Exhibit 10.58

January 10, 2014

Andy Inglis
Foxgloves
II Onslow Road
Hersham, Walton-on-Thames
Surrey, KT12 5BB, UK

RE: Offer of Employment

Dear Andy,

On behalf of the Kosmos organization, I am pleased to extend an offer of employment to you with Kosmos Energy, LLC (the " **Company**") as Chief Executive Officer. Additionally, the Company's Board of Directors (the "**Board**") will approve your nomination to serve as the Chairman of the Board immediately upon hire. This offer letter agreement (this "**Offer Letter**") serves to confirm the Company's offer of employment to you, including the following:

Start Date: Your employment with the Company will start on or about March 1, 2014 (the " **Start Date**").

Base Salary and Annual Bonus: You will receive a base salary at an initial annual rate of $900,000 (the " **Base Salary**"), payable in accordance with the Company's payroll practices as in effect from time to time. The Company currently pays salary on the 15th and the last day of each month. The Board (or a committee thereof) will review the Base Salary annually to determine whether to increase it. The Base Salary will not be decreased except in connection with a proportionate across-the-board decrease for the Company's senior executives generally.

You will be eligible for an annual bonus that will be targeted at 100% of the Base Salary (the "**Target Bonus**") and will be based on Company and individual performance metrics established annually by mutual agreement between you and the Board (or a committee thereof) not later than the 90th day of the applicable performance year. The actual bonus, if any, that you earn for any year will (1) be determined in the discretion of the Board (or a committee thereof), based on the level of attainment of the applicable Company and individual performance metrics within the context of prevailing market conditions and (2) may range between 0% and 200% of the Base Salary.

Sign-On Bonus:	A sign-on bonus of $1,675,000 (the "**Sign-On Bonus**") will be paid to you in cash in your first paycheck. If at any time prior to the first anniversary of the Start Date you terminate your employment for any reason other than Good Reason (as defined below) or the Company terminates your employment for Cause (as defined below), you will promptly reimburse the Company an amount equal to the product of (1) the gross amount of the Sign-On Bonus, *multiplied by* (2) a fraction, the numerator of which is 365 *minus* the number of calendar days during the period beginning on (and including) the Start Date and ending on (and including) the date of such termination, and the denominator of which is 365.
Sign-On Equity Awards:	On the first day of the calendar month following the Start Date, you will receive two awards (the "**Sign-On Equity Awards**") of restricted share units ("**RSUs**"). The Sign-On Equity Awards will be issued under the Kosmos Energy Ltd. Long Term Incentive Plan attached hereto as Exhibit A (such plan, or any successor thereto, the "**LTIP**") and will be subject to the terms (including, without limitation, the applicable vesting schedules and forfeiture restrictions) set forth in the LTIP and individual award agreements substantially in the forms attached hereto as Exhibits B and C. The Sign-On Equity Awards will have an aggregate value as of the grant date of $3,500,000, of which $1,000,000 will be granted in the form of service-vesting RSUs and $2,500,000 will be granted in the form of performance-vesting RSUs. The number of common shares of Kosmos underlying each Sign-On Equity Award (at target, in the case of the performance-vesting RSUs) will be determined in accordance with the terms of the LTIP by dividing the grant date value of such award by the closing price of a common share on the grant date.
Long Term Incentive ("LTI") Opportunity:	During your employment, you will be eligible for annual long-term incentive ("**LTI**") equity awards. Your initial LTI award will be granted no later than June 30, 2014, and will have an aggregate value as of the grant date of $2,250,000 (with any performance-based component of such award valued at target). It is the expectation of the Board that the LTI award, if any, granted for each year after 2014 will have an aggregate value as of the grant date equal to 2.5 times the Base Salary as in effect at the time of grant (with any performance-based component of such award valued at target); *however*, the actual aggregate value of each such post-2014 LTI award, if any, will be determined in the discretion of the Board (or a committee thereof). Each LTI award will be granted pursuant to the LTIP and one or more individual award agreements that contain such vesting and other terms as are no less favorable than such terms that apply to the LTI awards granted to the Company's senior executives generally. The number of common shares of Kosmos underlying each LTI award (at target, in the case of any performance-vesting RSUs) will be determined in accordance with the terms of the LTIP by dividing the grant date value of such award by the

closing price of a common share on the grant date.

Relocation:

You will be required to relocate your principal residence to the Dallas/Fort Worth area as soon as practicable after the Start Date. The Company will pay or reimburse you for all reasonable and customary costs associated with your relocation as follows:

- Packing and transporting standard furniture and personal effects belonging to you and members of your immediate family, to be performed by a moving company of your choice.

- The cost of airfare for you and members of your immediate family from the United Kingdom to Dallas, Texas.

- Reasonable expenses, including travel, for up to seven days for you and members of your immediate family to obtain housing in the Dallas/Fort Worth area.

- Expenses for necessary transitional temporary housing (to be approved by the Company in advance, with such approval not to be unreasonably withheld) for up to six months in the Dallas/Fort Worth area.

In addition, the Company will provide you with the following payments:

- A one-time lump sum cash payment of $5,000 to cover miscellaneous relocation expenses not otherwise provided in this section, payable in your first paycheck.

- A one-time lump sum cash payment of $25,000 to cover any loss on the sale of your two vehicles in the United Kingdom, payable in your first paycheck.

- A one-time lump sum cash payment of $120,000 to defray costs associated with the sale of your existing home and the purchase/lease of a new residence in the Dallas/Fort Worth area. You will be required to sell your existing home and either purchase or lease a home in the Dallas/Fort Worth area to receive this payment.

Except as otherwise provided above, any reimbursement of expenses pursuant to this " ***Relocation***" section will be made by the Company as soon as practicable following receipt of supporting documentation reasonably satisfactory to the Company(but in any event not later than December 31 of the year following the year in which the expense is incurred).

If at any time prior to the first anniversary of the Start Date you terminate your employment for any reason other than Good Reason or the Company terminates your employment for Cause, you will promptly reimburse the

Company an amount equal to the product of (1) the aggregate gross amount of all expenses paid or reimbursed by the Company pursuant to this "***Relocation***" section, *multiplied by* (2) a fraction, the numerator of which is 365 *minus* the number of calendar days during the period beginning on (and including) the Start Date and ending on (and including) the date of such termination, and the denominator of which is 365.

Spousal Assistance: The Company will provide employment assistance through The MI Group for your spouse. This benefit includes, but is not limited to, career counseling, employment search coaching, resume development, career development workshops, and employment search assistance. The use of this benefit is required to be commenced within 90 days after your move date to Dallas and to be completed within one year after such move date.

Severance Benefits: If at any time your employment is terminated by the Company without Cause or by you for Good Reason, then subject to your execution and non-revocation of a general release of claims provided by the Company and such release becoming effective not later than 60 days after such termination, and your continued compliance with any confidentiality covenants to which you are subject, the Company will: (1) pay you an amount (the "**Severance**") equal to the product of two, *multiplied by* the sum of the Base Salary plus the Target Bonus (in each case as in effect as of the date of such termination); (2) provide you with continued coverage under the Company's medical and dental plans for you and your dependents for 24 months following such termination with the Company paying the entire premium for such coverage (the "**Benefits Continuation**"); and (3) accelerate the vesting of any then unvested portion of the service-vesting Sign-On Equity Award. The Severance will be paid to you in equal monthly installments over the 24-month period following such termination; *provided* that the first payment shall be made on the Company's first regular payroll date that is more than 60 days after such termination, and any installments that otherwise would have been paid during such 60-day period will be paid on such first payroll date.

Notwithstanding the foregoing: (A) your entitlement to the Benefits Continuation will also be subject to your timely election to receive continued coverage for such benefits pursuant to the Consolidated Omnibus Budget Reconciliation Act of 1985 or analogous applicable state law; (B) the Company's obligation to pay for the Benefits Continuation will cease upon your becoming eligible for such coverage from a subsequent employer, and you will promptly notify the Company on your becoming eligible for such coverage; (C) in the event that you elect coverage under a plan provided by the Company that has a higher premium than the plan in which you participate as of the date on which your employment with the Company terminates, the amount of the Company's contribution to your premium payments will not increase from the amount of such contributions as of the date that your employment terminated, and you will be responsible for payment of any additional premium amount; and (D) if the Company reasonably determines that the Benefits Continuation cannot be provided to you for the full 24-month period and/or without your paying all or a portion of the premium for such coverage, in each case without subjecting the Company to adverse tax consequences or increased health insurance premiums, then the coverage period will be reduced and/or you will be required to pay the premium for such coverage, in each case to the extent that the Company reasonably determines is required to ensure that the Company is not subject to such adverse tax consequences or increased premiums; *provided* that, for any month during such 24-month period that you are not provided with such coverage or for which you are required to pay any portion of the premium for such coverage, the Company will provide you with a cash payment in an amount equal to, as applicable, (i) the full premium for such coverage for such month, if you are not provided with, or are required to pay the entire premium for, such coverage for such month or (ii) the portion of the premium for such coverage that you are required to pay for such month, but in each case only if the Company reasonably determines that providing such payment would not subject the Company to adverse tax consequences or increased health insurance premiums.

Change in Control:

In the event of a Change in Control (as defined in the LTIP) and contingent upon your continued service to the Company or its successor for one year thereafter, all of your equity awards that are unvested as of such Change in Control shall vest on the first anniversary of such Change in Control, with any performance-based equity awards vesting at target level; *provided*, *however*, that in the event that your employment with the Company is terminated by the Company or its successor without Cause or by you for Good Reason, in either case during the period beginning three months before and ending one year after a Change in Control, then all of your equity awards that are unvested as of the date of such termination shall vest in full on the later of the date of such termination or the date of such Change in Control; *provided further*, *however*, that in the case of any such termination that occurs during the period prior to a Change in Control, such vesting of your equity awards shall only apply if such termination was at the request of a third party that has taken steps reasonably calculated to effectuate such Change in Control or that otherwise arose in connection with or anticipation of such Change in Control.

If the payments that you would receive in connection with a Change in Control from the Company or otherwise (collectively, "**Payments**") would (i) constitute "parachute payments" within the meaning of Section 280G of the Internal Code of 1986, as amended (the "**Code**"), and (ii) but for this sentence, be subject to the excise tax imposed by Section 4999 of the Code, then the aggregate amount of such Payments shall be reduced to the extent necessary to avoid such excise tax, but only if the Net After-Tax Benefit taking into account such reduction exceeds the Net After-Tax Benefit without taking into account such reduction. "**Net After-Tax Benefit**" means the present value (as determined by the Company in accordance with Section 280G(d)(4) of the Code) of the Payments net of all taxes imposed on you with respect thereto under Sections 1 and 4999 of the Code and under applicable state and local laws.

Notwithstanding any provision to the contrary in this Offer Letter, the LTIP or any other applicable agreement or plan, any reduction in the Payments required under the preceding paragraph shall be implemented as follows: *first*, by reducing the Severance; *second*, by reducing any other cash payments to be made to you; *third*, by cancelling any outstanding performance-based equity awards whose performance goals were not met prior to the Change in Control; *fourth*, by cancelling the acceleration of vesting of any outstanding (i) performance-based equity awards whose performance goals were met prior to the Change in Control and (ii) service-vesting equity awards; and *fifth*, by eliminating the Benefits Continuation. In the case of the reductions to be made pursuant to each of the foregoing clauses, the payment and/or benefit amounts to be reduced, and the acceleration of vesting to be cancelled, shall be reduced or cancelled in the inverse order of their originally scheduled dates of payment or vesting, as applicable, and shall be so reduced only to the extent that the payment and/or benefit otherwise to be paid, or the vesting of the award that otherwise would be accelerated, would be treated as a "parachute payment".

401(k) Plan: You will be eligible to participate in the Company's 401(k) plan starting on the Start Date. Currently, the Company matches employees' contributions to the plan dollar for dollar up to the lesser of 8% of eligible compensation contributed or the applicable Internal Revenue Service maximum ($17,500 for 2013). The Company match is not guaranteed to remain at the same level. You will be notified if there is a plan contribution or design change.

Other Benefits: You will be entitled to participate in the Company's other benefit plans applicable to full-time regular employees. For the 2013 calendar year, the Company is paying 100% of the cost of such benefit plans. The Company reserves the right to change the benefits provided or the costs charged to employees at any time in its sole discretion; *provided*, *however*, that the Company will not decrease your benefits, or the portion of your benefits costs borne by the Company, except in connection with such an across-the-board decrease for the Company's U.S.-based senior executives generally.

Vacation: Based on your years of relevant industry-related work experience, the Company will provide with you with five weeks of annual vacation allowance (prorated for the first year of your employment based on the number of calendar days that you are employed in such year).

Holidays: The Company's current practice is to provide employees with nine nationally recognized major U.S. holidays and up to two additional "floating" holidays of their choice. The Company reserves the right to change this general practice at any time in its sole discretion.

Withholding: The Company may withhold from any amounts payable or benefits provided to you under this Offer Letter or otherwise such federal, state and local taxes as may be required to be withheld pursuant to any applicable law or regulation.

Legal Fees: The Company agrees to reimburse 50% of the reasonable legal fees incurred by you in the analysis, negotiation, and preparation of this Offer Letter and advice regarding related matters; *provided* that in no event shall such reimbursement obligation exceed $15,000. Such reimbursement will be made by the Company as soon as practicable following receipt of supporting documentation reasonably satisfactory to the Company (but in any event not later than December 31 of the year following the year in which the expense is incurred).

Ability to Accept Employment: You hereby represent to the Company that you are not subject to any notice requirement, garden leave provision, non-competition covenant or any similar requirement, provision or covenant (each such requirement, provision or covenant, an "**Employment Restriction**") that would prevent you from accepting this offer of employment with the Company, commencing such employment or remaining an employee of the Company or becoming or remaining a director of Kosmos or that would adversely impact your ability to perform your duties to the Company or Kosmos.

Your employment with the Company and this Offer Letter are expressly contingent on your (1) ability to start employment with the Company on the Start Date without your breaching any Employment Restriction and (2) completion of a reference and background check, including but not limited to past employment, education, credit reports and criminal records, to the reasonable satisfaction of the Board.

Notwithstanding anything to the contrary in this Offer Letter or any other agreement between you and the Company, the LTIP or any equity award agreement provided to you, if at any time you are prevented from remaining an employee of the Company or performing your duties to the Company due to any Employment Restriction, the Company will be entitled to terminate your employment, and such termination shall be deemed a termination for Cause for all purposes under this Offer Letter, any such other agreement, the LTIP and any such equity award agreement.

Definitions: "**Cause**" means your:

(1) material failure to perform your duties to the Company or any Affiliate (as defined in the LTIP), other than any such failure

resulting from your physical or mental incapacity;

(2) having engaged in serious misconduct, gross negligence or a material breach of fiduciary duty;

(3) having been convicted of, or having entered a plea bargain or settlement admitting guilt or the imposition of unadjudicated probation for, any crime of moral turpitude or felony under any applicable law;

(4) material breach of any Employment Restriction or material breach of any restrictive covenant to which you are subject contained in any agreement between you and the Company or any Affiliate;

(5) material breach of any policy of the Company or any Affiliate, including, without limitation, any such policy that relates to expense management or the Foreign Corrupt Practices Act;

(6) unlawful use or possession of illegal drugs on the premises of the Company or any Affiliate or while performing your duties to the Company or any Affiliate; or

(7) commission of an act of fraud, embezzlement or misappropriation, in each case, against the Company or any Affiliate;

provided that, in the event that the Company believes that you have committed an act giving rise to Cause under clauses (1), (2), (4) or (5), then, if such Cause is reasonably susceptible of cure, (A) the Company will provide you written notice specifying the alleged circumstances constituting Cause within 90 days following the Board's first obtaining knowledge of the occurrence of such circumstances, (B) you shall have 30 days following receipt of such notice to cure such circumstances and (C) if not cured, the Company may terminate your employment not later than 60 days after the end of such cure period.

"**Good Reason**" means the occurrence of any of the following events, in each case without your consent:

(1) a reduction in the Base Salary or Target Bonus, other than any such reduction that applies generally to senior executives of the Company and the Affiliates;

(2) relocation of the geographic location of your principal place of employment by more than 50 miles; or

(3) a material reduction in your duties or responsibilities;

provided that, in each case, (A) you shall provide the Company with written notice specifying the circumstances alleged to constitute Good Reason within 90 days following the first occurrence of such circumstances, (B) the Company shall have 30 days following receipt of such notice to cure such circumstances and (C) if the Company has not cured such circumstances within such 30-day period, then you must terminate your employment not later than 60 days after the end of such 30-day period.

Miscellaneous:

The Company's and your respective rights and obligations shall survive any termination of this Offer Letter to the extent necessary for the intended preservation of such rights and obligations.

This Offer Letter is intended to bind and inure to the benefit of and be enforceable by you and your estate, the Company and your and the Company's successors and assigns. You may not assign your rights or delegate your duties or obligations hereunder without the prior written consent of the Company. The Company may assign its rights and obligations hereunder, without the consent of, or notice to, you, to any of the Company's affiliates or to any person or entity that acquires the Company or any portion of its business or its assets pursuant to a merger, consolidation or other transaction, in which case all references to the Company will refer to such assignee.

Any provision in this Offer Letter that is prohibited or unenforceable in any jurisdiction by reason of applicable law shall, as to such jurisdiction, be ineffective only to the extent of such prohibition or unenforceability without invalidating or affecting the remaining provisions hereof, and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction.

This Offer Letter (together with the LTIP), constitutes the entire agreement of the parties with regard to the subject matter hereof and supersedes any and all prior understandings, agreements, communications, or correspondence between the parties. Any modification of this Offer Letter will be effective only if it is in writing and signed by the party to be charged. The failure of a party to insist on strict adherence to any term of this Offer Letter on any occasion shall not be considered a waiver of such party's rights or deprive such party of the right thereafter to insist upon strict adherence to that term or any other term of this Offer Letter.

This Offer Letter shall be governed by, and construed in accordance with, the laws of the State of Texas without regard to any otherwise applicable conflicts of law principles, whether of the State of Texas or otherwise. To ensure the rapid, economical, and confidential resolution of disputes that may arise in connection with your employment, you and the Company agree that any and all disputes, claims, or causes of action, in law or equity, arising from or relating to the enforcement, breach, performance, or interpretation of this Offer Letter, your employment with the Company, or the termination of that employment, shall be resolved, to the fullest extent permitted by law, by final, binding and confidential arbitration in Dallas, Texas conducted by the American Arbitration Association or its successor under its then-applicable Commercial Arbitration Rules, and judgment on the arbitral award rendered may be entered in any court having jurisdiction thereof. **By agreeing to this arbitration procedure, both you and the Company waive the right to resolve any such dispute through a trial by jury or judge or administrative proceeding.** You will have the right to be represented by legal counsel at any arbitration proceeding. The arbitrator shall: (a) have the authority to compel adequate discovery for the resolution of the dispute and to award such relief as would otherwise be permitted by law; and (b) issue a written statement signed by the arbitrator regarding the disposition of each claim and the relief, if any, awarded as to each claim, the reasons for the award, and the arbitrator's essential findings and conclusions on which the award is based. The arbitrator shall be authorized to award all relief that you or the Company would be entitled to seek in a court of law. Nothing in this Offer Letter is intended to prevent either you or the Company from obtaining injunctive relief in court to prevent irreparable harm pending the conclusion of any such arbitration.

This Offer Letter may be signed in counterparts, each of which shall be an original, with the same effect as if the signatures thereto and hereto were upon the same instrument.

Section 409A: Notwithstanding anything in this Offer Letter to the contrary, if you are a "specified employee" (determined in accordance with Section 409A of the Code ("**Section 409A**")) as of the date that your employment with the Company terminates and you have experienced a "separation from service" (within the meaning of Section 409A), and if any payment, benefit or entitlement provided for in this Offer Letter or otherwise both (1) constitutes a "deferral of compensation" within the meaning of Section 409A and (2) cannot be paid or provided in a manner otherwise provided herein or otherwise without subjecting you to additional tax, interest or penalties under Section 409A, then any such payment, benefit or entitlement that is payable during the first six months following such termination will be paid or provided to you in a lump sum cash payment to be made on the earlier of (A) your death or (B) the first business day of the seventh calendar month immediately following the month in which such termination occurs.

Your employment with the Company will be at-will and nothing in this Offer Letter shall be deemed to be construed as a contract for a term of employment.

We look forward to receiving a response from you within the next week. If you have any additional questions, please do not hesitate to call me directly or Ty Gaston at 214-445-9686.

We believe Kosmos is an outstanding organization with a capable, dedicated team and know you will be a valuable, enthusiastic addition.

Sincerely,
/s/ Prakash A. Melwani
Chairman of the Compensation Committee
Kosmos Energy Ltd.

Exhibit 10.66

KOSMOS ENERGY

Severance Policy

It is the policy of Kosmos Energy Ltd. and its subsidiaries (the "Company" or "Kosmos") to offer eligible U.S. employees severance benefits when a termination is initiated by the Company through no fault of the employee in connection with a change in control. As defined below, Kosmos will offer severance pay, a prorated target bonus, the cash equivalent to cover the cost of benefits continuation, and outplacement services to any employee who meets the defined eligibility requirements. Severance benefits will be offered according to the attached severance formula matrix.

Eligibility

In connection with a change in control at Kosmos as defined in the Company's Long Term Incentive Plan ("Change in Control"), regular full-time U.S. employees whose employment has terminated as a result of the following reasons will generally be eligible for severance benefits:

- Reduction in the work force.

- Reorganization of department(s) that results in the elimination of the job.

- Reorganization of department(s) that results in the diminution of the skills, requirements, aptitudes, or other criteria of the position in a material manner, as determined by the Company in its reasonable discretion, where the employee declines an offer to continue employment in the altered position or another position that the Company deems comparable in its reasonable discretion before any deadline and in the manner prescribed by the Company.

- Relocation of the job functions outside of a 50-mile radius where the employee is not offered employment at the new location or declines an offer of employment at the new location.

Employees will be ineligible for severance benefits where employment terminates for any other reason following a Change in Control.

Eligible employees who already have a separate severance agreement with the Company may receive severance benefits only under either that agreement or this Policy. Under no circumstances may an eligible employee receive severance benefits under both arrangements.

Severance Plan Details

Separation and General Release Agreement

To receive the severance benefits, an eligible employee must to sign and not revoke, if applicable, a Separation and General Release Agreement in the form prescribed by the Company.

Benefits Schedule

Severance benefits are generally based on years of service and job level. Attached is the severance formula matrix. Supplemental Severance Pay will be prorated based on partial years of service.

Annual Bonus Payment

As part of the severance benefits, the Company will offer eligible employees a prorated portion of their annual target bonus for the current year, if not yet already paid.

Health and Welfare Benefits

As part of the severance benefits , Kosmos will offer to pay eligible employees the cash equivalent to the monthly premium cost of continued coverage under COBRA multiplied by the number of months of the Minimum Severance Payout that the eligible employee would receive in accordance with the attached severance formula matrix.

Outplacement

Outplacement services are designed to assist individuals with various aspects of their future job search. These services will be provided at the cost of Kosmos. Outplacement services will be provided by a reputable outplacement firm at the sole choosing of Kosmos. The duration of outplacement services offered as part of the severance benefits is provided on the attached severance formula matrix.

Vacation Payout

Eligible employees will receive a payout of all unused vacation and rollover vacation time.

Rehire

Employees terminated following a Change in Control through no fault of their own, will generally be eligible for rehire.

Exceptions

Any exceptions to this policy for Company Vice Presidents and below must be approved, in writing, by the SVP of Global Human Resources. There shall be no exceptions or deviations from this policy for Senior Vice Presidents and above ("Executive Officers") unless agreed to in writing by the Executive Officer and the Compensation Committee of Kosmos Energy Ltd.'s Board of Directors.

Changes

Kosmos may amend or terminate this policy at any time, with or without notice.

Kosmos Severance Formula Matrix - Tiered Plan

Job Level	Minimum Severance Payout	Supplemental Severance Pay	Health and Welfare Pay	Outplacement Services
Members of the SLT	24 months	4 weeks per year of service	Cash Payment equivalent to the COBRA cost for the total severance period	18 months
SVPs not on the SLT and VPs	12 months	4 weeks per year of service	Cash Payment equivalent to the COBRA cost for the total severance period	18 months
Sr. Director/Director/Petro and Geo Technical Professional	9 months	3 weeks per year of service	Cash Payment equivalent to the COBRA cost for the total severance period	6 months
Sr. Manager/Manager	6 months	3 weeks per year of service	Cash Payment equivalent to the COBRA cost for the total severance period	3 months
Support/Individual Contributor	3 months	2 weeks per year of service	Cash Payment equivalent to the COBRA cost for the total severance period	3 months

** 18 month maximum severance payout shall apply to all non-SLT members

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Exhibit 21.1

List of Subsidiaries

Subsidiary	Jurisdiction of Incorporation
Kosmos Energy Ltd.	Bermuda
Kosmos Energy Holdings	Cayman Islands
Kosmos Energy LLC	Texas
Kosmos Energy Operating	Cayman Islands
Kosmos Energy Ventures	Cayman Islands
Kosmos Energy South Atlantic	Cayman Islands
Kosmos Energy Latin America	Cayman Islands
Kosmos Energy Brasil Oleo e Gas Ltda.	Brazil
Kosmos Energy Deepwater Morocco	Cayman Islands
Kosmos Energy Cameroon HC	Cayman Islands
Kosmos Energy Offshore Morocco HC	Cayman Islands
Kosmos Energy Finance International	Cayman Islands
Kosmos Energy Finance	Cayman Islands
Kosmos Energy International	Cayman Islands
Kosmos Energy Development	Cayman Islands
Kosmos Energy Ghana HC	Cayman Islands
Kosmos Energy Suriname	Cayman Islands
Kosmos Energy Ireland	Cayman Islands
Kosmos Energy Mauritani	Cayman Islands
Kosmos Energy Sierra Leone	Cayman Islands
Kosmos Energy Equatorial Guinea	Cayman Islands
Kosmos Energy Credit International	Cayman Islands
FATE Energy Services	Cayman Islands
Kosmos Energy Operating Service SARL	Morocco
Kosmos Energy Liberia	Cayman Islands

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Exhibit 21.1

List of Subsidiaries

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Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statement (Form S-8 No. 333-174234) pertaining to the Kosmos Energy Ltd. Long Term Incentive Plan and the Registration Statement (Form S-3 No. 333-182280) of Kosmos Energy Ltd. and in the related Prospectus of our reports dated February 24, 2014, with respect to the consolidated financial statements and schedules and the effectiveness of internal control over financial reporting of Kosmos Energy Ltd., included in this Annual Report (Form 10-K) for the year ended December 31, 2013.

/s/ Ernst & Young LLP

Dallas, Texas
February 24, 2014

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Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

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Exhibit 23.2

NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the reference of our firm and to the use of our reports effective December 31, 2013; December 31, 2012; and December 31, 2011, dated January 15, 2014; January 28, 2013; and February 16, 2012, respectively, in the Kosmos Energy Annual Report on Form 10-K for theyear ended December 31, 2013, to be filed with the U. S. Securities and Exchange Commission on or about February 24, 2014.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ C.H. (SCOTT) REES III, P.E.

C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

Dallas, Texas
February 13, 2014

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Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

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Exhibit 31.1

Certification of Chief Executive Officer

I, Brian F. Maxted, certify that:

1. I have reviewed this annual report on Form 10-K of Kosmos Energy Ltd.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2014

/s/ BRIAN F. MAXTED

Brian F. Maxted
Director and Chief Executive Officer
(Principal Executive Officer)

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Exhibit 31.2

Certification of Chief Financial Officer

I, W. Greg Dunlevy, certify that:

1. I have reviewed this annual report on Form 10-K of Kosmos Energy Ltd.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2014	/s/ W. GREG DUNLEVY
	W. Greg Dunlevy *Executive Vice President and Chief Financial Officer* *(Principal Financial Officer)*

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Exhibit 32.1

Certification of Chief Executive Officer
Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the accompanying annual report of Kosmos Energy Ltd. (the "Company") on Form 10-K for the period ended December 31, 2013, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Brian F. Maxted, Director and Chief Executive Officer of the Company, hereby certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 24, 2014

/s/ BRIAN F. MAXTED

Brian F. Maxted
Director and Chief Executive Officer
(Principal Executive Officer)

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

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Exhibit 32.2

Certification of Chief Financial Officer
Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the annual report of Kosmos Energy Ltd. (the "Company") on Form 10-K for the period ended December 31, 2013, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, W. Greg Dunlevy, Chief Financial Officer and Executive Vice President of the Company, hereby certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 24, 2014

/s/ W. GREG DUNLEVY

W. Greg Dunlevy
Chief Financial Officer and Executive Vice President
(Principal Financial Officer)

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

CHAIRMAN & CEO
C.H. (SCOTT) REES III
PRESIDENT & COO
DANNY D. SIMMONS
EXECUTIVE VP
G. LANCE BINDER

EXECUTIVE COMMITTEE
P. SCOTT FROST - DALLAS
J. CARTER HENSON, JR. - HOUSTON
DAN PAUL SMITH - DALLAS
JOSEPH J. SPELLMAN - DALLAS
THOMAS J. TELLA II - DALLAS

January 15, 2014

Mr. Doug Trumbauer
Kosmos Energy
8176 Park Lane, Suite 500
Dallas, Texas 75231

Dear Mr. Trumbauer:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2013, to the Kosmos Energy (Kosmos) interest in the LM2, UM3, and UM2 Reservoirs for the Jubilee Field Development Unit Area located in the West Cape Three Points and Deepwater Tano license areas, offshore Ghana. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by Kosmos. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Kosmos' use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Kosmos interest in these reservoirs for the Jubilee Field Development Unit Area, as of December 31, 2013, to be:

	Net Reserves(1)		Future Net Revenue(1) (MM$)	
Category	Oil (MMBBL)	Gas(2) (BCF)	Total	Present Worth at 10%
Proved Developed Producing	25	9	1,539	1,313
Proved Developed Non-Producing	11	1	775	566
Proved Undeveloped	9	1	497	338
Total Proved	45	11	2,811	2,217

(1) Kosmos' unitized net interest is based on the 54.3666/45.6334 percent equity redetermination split effective December 1, 2011, between the West Cape Three Points and Deepwater Tano license areas; this is subject to change as additional data are obtained.

(2) There is currently no market for produced gas. As requested, fuel gas consumed in operations has been estimated and included as reserves. Net gas reserves are gas volumes consumed in operations as fuel, limited to a maximum rate of 10 million cubic feet per day; for the purposes of this report, all other produced gas will be reinjected or flared.

The oil volumes shown include crude oil only. Oil volumes are expressed in millions of barrels (MMBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in billions of cubic feet (BCF) at standard temperature and pressure bases. Monetary values shown in this report are expressed in United States dollars ($) or millions of United States dollars (MM$).

The estimates shown in this report are for proved reserves. As requested, probable and possible reserves that exist for these properties have not been included. This report does not include any value that could be attributed

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to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue is Kosmos' share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Kosmos' share of production sharing oil revenue; capital costs; abandonment costs; operating expenses; exploration, development, and production royalties paid to the Ghanaian government; and estimated Ghanaian taxes but before consideration of United States income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2013. The average Europe Brent Spot (Platt's) price of $108.02 per barrel is adjusted by lease for crude handling, quality, transportation fees, and a regional price differential. Based largely on the high quality of the crude, these adjustments are estimated to add $0.74 per barrel. The adjusted oil price of $108.76 per barrel is held constant throughout the lives of the properties. There is no gas price used in this report because produced gas is consumed in operations as fuel.

Operating costs used in this report are based on operating expense records provided by Kosmos. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Since all properties are nonoperated, headquarters general and administrative overhead expenses of Kosmos are not included. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Kosmos and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Kosmos' estimates of the costs to abandon the wells, platforms, and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Kosmos interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Kosmos receiving its net revenue interest share of estimated future gross production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using a combination of deterministic and probabilistic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for undeveloped locations and producing wells that lack sufficient production history upon which performance-related estimates of reserves can be based; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Kosmos, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. and were accepted as accurate. Supporting work data are on file in our office. We have not examined the contractual rights to the properties or independently confirmed the actual degree or type of interest owned. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Joseph J. Spellman
Joseph J. Spellman, P.E. 73709
Senior Vice President

Date Signed: January 15, 2014

By: /s/ Daniel T. Walker
Daniel T. Walker, P.G. 1272
Senior Vice President

Date Signed: January 15, 2014

JJS:ABB

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves — Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves — Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

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(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and

(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90%

probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. *Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
b. *Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*
e. *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.