Kosmos Energy Ltd.
Form 10-Q
November 10, 2011
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2011

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

For the transition period from to

Commission file number: 001-35167

Kosmos Energy Ltd.

(Exact name of registrant as specified in its charter)

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

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

Not applicable

(Former name, former address and former fiscal year, if changed since last report)

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 x No o

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 x No o

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 o	Accelerated filer o
Non-accelerated filer x (Do not check if a smaller reporting company)	Smaller reporting company o

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

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date.

Class	**Outstanding at November 1, 2011**
Common Shares, $0.01 par value	389,867,068

KOSMOS ENERGY LTD.

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GLOSSARY AND SELECT ABBREVIATIONS

The following are abbreviations and definitions of certain terms used in this report. Unless listed below, all defined terms under Rule 4-10(a) of Regulation S-X shall have their statutorily prescribed meanings.

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.
boe	Barrels of oil equivalent. Volumes of natural gas are 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.
Dated Brent	Refers to a cargo of blended North Sea Brent crude oil that has been assigned a date for loading onto a tanker. Physically, Brent is light but still heavier than West Texas Intermediate crude.
Development	The phase in which an oil or natural gas field is brought into production by drilling development wells and installing appropriate production systems.
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.
Drilling and completion costs	All costs, excluding operating costs, of drilling, completing, testing, equipping and bringing a well into production or plugging and abandoning it, including all costs associated with labor and other construction and installation, location and surface damages, cementing, drilling mud and chemicals, drillstem tests and core analysis, engineering and well site geological expenses, electric logs, plugging back, deepening, rework operations, repairing or performing remedial work of any type, plugging and abandoning.
Dry hole	A well that has not encountered a hydrocarbon bearing reservoir.
E&P	Exploration and production.
Exploration well or *Exploratory well*	A well drilled either (a) in search of a new and an as yet undiscovered pool of oil or natural gas or (b) with the hope of significantly extending the limits of a pool already developed.
FASB	Financial Accounting Standards Board.
Field	A geographical area under which an oil or natural gas reservoir exists in commercial quantities.
Finding and development costs	Capital costs incurred in the acquisition, exploration, appraisal and development of proved oil and natural gas reserves divided by proved reserve additions.
FPSO	Floating production, storage and offloading vessel.
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	Natural gas is a combination of light hydrocarbons that, in average pressure and temperature conditions, is found in a gaseous state. In nature, it is found in underground accumulations, and may potentially be dissolved in oil or may also be found in its gaseous state.
Plan of development or *PoD*	A written document outlining the steps to develop a field.
Producing well	A well that is found to be capable of producing hydrocarbons in sufficient quantities so that proceeds from the sale of such production exceed production expenses and taxes.

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.

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Proved reserves	Estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be economically recoverable in future years from known reservoirs under existing economic and operating conditions, as well as additional reserves expected to be obtained through confirmed improved recovery techniques, as defined in SEC Regulation S-X 4-10(a)(2).
Royalty	A fractional undivided interest in the production of oil and natural gas wells or the proceeds therefrom to be received free and clear of all costs of development, operations or maintenance.
Working interest	A percentage of ownership in an oil and gas license granting its owner the right to explore, drill and produce oil and gas from a tract of property. Working interest owners are typically obligated to pay a corresponding percentage of the cost of leasing, drilling, producing and operating a well or unit. The working interest also entitles its owner to share in production with other working interest owners based on the percentage of working interest owned.

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CONSOLIDATED BALANCE SHEETS

(In thousands, except share data)

	September 30, 2011 (Unaudited)	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 656,442	$ 100,415
Restricted cash	22,949	80,000
Receivables:		
Joint interest billings	89,614	124,449
Oil sales	114,933	
Notes	109,441	113,889
Other	4,734	615
Inventories	33,010	37,674
Prepaid expenses and other	15,733	13,278
Current deferred tax assets	50,127	89,600
Total current assets	1,096,983	559,920
Property and equipment:		
Oil and gas properties, net of accumulated depletion of $90,872 and $6,430, respectively	1,122,904	989,869
Other property, net of accumulated depreciation of $7,300 and $5,343, respectively	8,102	8,131
Property and equipment - net	1,131,006	998,000
Other assets:		
Restricted cash	3,500	32,000
Long-term receivables - joint interest billings, net of allowance		21,897
Deferred financing costs and other assets, net of accumulated amortization of $4,388 and $32,093, respectively	57,041	78,217
Long-term deferred tax assets	2,297	
Derivatives		1,501
Total assets	$ 2,290,827	$ 1,691,535
Liabilities and shareholders equity/unit holdings equity		
Current liabilities:		
Current maturities of long-term debt	$	$ 245,000
Accounts payable	197,224	163,495
Accrued liabilities	41,409	53,208
Derivatives	30,023	20,354
Total current liabilities	268,656	482,057
Long-term liabilities:		
Long-term debt	1,000,000	800,000
Derivatives	9,674	15,104
Asset retirement obligations	19,622	16,752
Deferred tax liability	12,513	12,513
Other long-term liabilities	15,661	1,014

Total long-term liabilities		1,057,470		845,383
Convertible preferred units, 100,000,000 units authorized:				
Series A zero and 30,000,000 units issued at September 30, 2011 and December 31, 2010, respectively				383,246
Series B zero and 20,000,000 units issued at September 30, 2011 and December 31, 2010, respectively				568,163
Series C zero and 884,956 units issued at September 30, 2011 and December 31, 2010, respectively				27,097
Shareholders equity/unit holdings equity:				
Preference shares, $0.01 par value; 200,000,000 authorized shares; zero issued at September 30, 2011 and December 31, 2010				
Common shares, $0.01 par value; 2,000,000,000 authorized shares; 390,214,659 and zero issued at September 30, 2011 and December 31, 2010, respectively		3,902		
Common units, 100,000,000 units authorized; zero and 19,069,662 issued at September 30, 2011 and December 31, 2010, respectively				516
Additional paid-in capital		1,607,754		
Accumulated deficit		(650,471)		(615,515)
Accumulated other comprehensive income		3,522		588
Treasury stock, at cost, 646,235 and zero shares at September 30, 2011 and December 31, 2010, respectively		(6)		
Total shareholders equity/unit holdings equity		964,701		(614,411)
Total liabilities, convertible preferred units and shareholders equity/unit holdings equity	$	2,290,827	$	1,691,535

See accompanying notes.

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KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)

(Unaudited)

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Revenues and other income:				
Oil and gas revenue	$ 230,262	$	$ 446,914	$
Interest income	2,492	675	7,459	2,548
Other income	91	1,313	735	3,793
Total revenues and other income	232,845	1,988	455,108	6,341
Costs and expenses:				
Oil and gas production	24,185		58,481	
Exploration expenses, including dry holes	11,005	18,960	104,657	52,764
General and administrative	39,093	27,845	72,140	50,804
Depletion and depreciation	42,593	578	88,960	1,655
Amortization - deferred financing costs	2,194	7,644	13,999	20,555
Interest expense	16,581	19,146	55,239	45,645
Derivatives, net	(4,984)	10,339	5,250	15,310
Loss on extinguishment of debt			59,643	
Doubtful accounts expense			(39,782)	
Other expenses, net	(79)	31	(18)	20
Total costs and expenses	130,588	84,543	418,569	186,753
Income (loss) before income taxes	102,257	(82,555)	36,539	(180,412)
Income tax expense (benefit)	50,481	(6)	48,505	(174)
Net income (loss)	51,776	(82,549)	(11,966)	(180,238)
Accretion to redemption value of convertible preferred units		(16,661)	(24,442)	(48,602)
Net income (loss) attributable to common shareholders/unit holders	$ 51,776	$ (99,210)	$ (36,408)	$ (228,840)
Net income (loss) per share attributable to common shareholders:				
Basic	$ 0.13			
Diluted	$ 0.13			
Pro forma basic			$ (0.03)	
Pro forma diluted			$ (0.03)	
Weighted average number of shares used to compute net income (loss) per share:				
Basic	368,996			
Diluted	369,341			

Pro forma basic	349,792
Pro forma diluted	349,792

See accompanying notes.

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CONSOLIDATED STATEMENTS OF SHAREHOLDERS EQUITY/UNIT HOLDINGS EQUITY

(In thousands)

(Unaudited)

	Common Units		Common Shares		Additional Paid-in	Accumulated	Accumulated Other 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)								
Equity-based compensation					29,264				29,264
Derivatives, net							2, 934		2,934
Accrete convertible preferred units to redemption amount					(1,452)	(22,990)			(24,442)
Common 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
Restricted stock awards			14,520	145	(145)				
Restricted stock forfeitures					6			(6)	
Net loss						(11,966)			(11,966)
Balance as of September 30, 2011		$	390,215	$ 3,902	$ 1,607,754	$ (650,471)	$ 3,522	$ (6)	$ 964,701

See accompanying notes.

KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

(Unaudited)

	Nine Months Ended September 30, 2011	2010
Operating activities		
Net loss	$ (11,966)	$ (180,238)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depletion, depreciation and amortization	102,959	22,210
Deferred income taxes	37,176	
Unsuccessful well costs	87,845	43,127
Derivative related activity	8,674	25,630
Equity-based compensation	29,264	1,672
Doubtful accounts expense	(39,782)	
Loss on extinguishment of debt	59,643	
Other	1,939	(265)
Changes in assets and liabilities:		
Increase in receivables	(36,786)	(59,696)
(Increase) decrease in inventories	2,126	(3,188)
Increase in prepaid expenses and other	(2,455)	(6,216)
Increase in accounts payable	33,729	34,574
Decrease in accrued liabilities	(5,220)	(10,790)
Net cash provided by (used in) operating activities	267,146	(133,180)
Investing activities		
Oil and gas assets	(282,098)	(330,173)
Other property	(1,928)	(1,113)
Notes receivable	4,448	(60,878)
Restricted cash	85,551	(59,000)
Net cash used in investing activities	(194,027)	(451,164)
Financing activities		
Borrowings under long-term debt	1,393,000	665,000
Payments on long-term debt	(1,438,000)	
Net proceeds from the initial public offering	580,374	
Deferred financing costs	(52,466)	(17,315)
Net cash provided by financing activities	482,908	647,685
Net increase in cash and cash equivalents	556,027	63,341
Cash and cash equivalents at beginning of period	100,415	139,505
Cash and cash equivalents at end of period	$ 656,442	$ 202,846
Supplemental cash flow information		
Cash paid for:		
Interest	$ 36,854	$ 35,125
Income taxes	$ 850	$ 762

Non-cash activity:		
Deemed payment and termination of notes receivable	$	$ 90,197

See accompanying notes.

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KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(In thousands)

(Unaudited)

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Net income (loss)	$ 51,776	$ (82,549)	$ (11,966)	$ (180,238)
Other comprehensive income (loss):				
Change in fair value of cash flow hedges				(4,838)
Loss on cash flow hedge included in operations	1,193	1,278	2,934	4,383
Other comprehensive income (loss)	1,193	1,278	2,934	(455)
Comprehensive income (loss)	$ 52,969	$ (81,271)	$ (9,032)	$ (180,693)

See accompanying notes.

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KOSMOS ENERGY LTD.

Notes to Consolidated Financial Statements

(Unaudited)

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 March 5, 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 r 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 an independent oil and gas exploration and production company focused on underexplored regions in Africa. Kosmos Energy Ltd. transitioned from its development stage to operational activities in January 2011. Accordingly, reporting as a development stage company is no longer deemed necessary.

Contemporaneous with Kosmos Energy Ltd. s initial public offering, the Series A Convertible Preferred Units, Series B Convertible Preferred Units and Series C Convertible Preferred Units (collectively the Convertible Preferred Units) and common units of Kosmos Energy Holdings were exchanged into common shares 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 277,697,828 and 63,478,643 common shares of Kosmos Energy Ltd., respectively, or 341,176,471 common shares in the aggregate. The 341,176,471 common shares included 10,032,827 restricted shares 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.

Kosmos Energy Ltd. completed its initial public offering of 33,000,000 common shares on May 16, 2011. In June 2011, the Company closed the sale of an additional 1,518,242 common shares pursuant to the over-allotment option exercised by the underwriters of the initial public offering. This partial exercise of the over-allotment option brings the total number of common shares sold in the offering to 34,518,242. Our net proceeds from the sale of 34,518,242 common shares, after underwriting discounts and commissions and offering expenses, were $580.4 million.

We have one business segment, which is the exploration and production of oil and natural gas.

2. Accounting Policies

General

The interim-period financial information presented in the consolidated financial statements included in this report is unaudited and, in the opinion of management, includes all adjustments of a normal recurring nature necessary to present fairly the consolidated financial position as of September 30, 2011, the consolidated results of operations for the three and nine months ended September 30, 2011 and 2010, and consolidated cash flows for the nine months ended September 30, 2011 and 2010. The results of the interim periods shown in this report are not necessarily indicative of the final results to be expected for the full year. These consolidated financial statements and the accompanying notes should be read in conjunction with our audited consolidated financial statements for the year ended December 31, 2010, included in our final prospectus.

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.

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.

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Cash and Cash Equivalents

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

Restricted Cash

As of September 30, 2011, we had $22.9 million of current restricted cash related to funds that will be utilized for payment on interest and commitment fees on our commercial debt facility. In accordance with our commercial debt facility, we are required to maintain a balance that is sufficient to meet the payment of interest and fees for the next six-month period. The $3.5 million long-term restricted cash is related to cash collateralization for performance guarantees related to our petroleum agreements.

As of December 31, 2010, in accordance with our commercial debt facilities that existed as of December 31, 2010, we had restricted cash of $89.0 million, of which $80.0 million was included in current assets. Additionally, effective December 30, 2010, we provided a $23.0 million cash collateralized irrevocable standby letter of credit (Letter of Credit) with respect to our share of Tullow Ghana Limited s (TGL) Letter of Credit related to TGL s drilling contract for the Eirik Raude semi-submersible rig. In March 2011, the restricted cash related to the debt facilities agreement and the cash collateral for the Letter of Credit was released as a result of our debt refinancing. The Letter of Credit was collateralized by our available borrowing capacity under the commercial debt facility until it expired on September 14, 2011.

Receivables

The Company s receivables consist of joint interest billings, oil sales, notes and other receivables for which the Company generally does not require collateral security. Receivables from joint interest owners are stated at amounts due, net of an allowance 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. The Company s allowances for doubtful accounts totaled zero and $39.8 million as of September 30, 2011 and December 31, 2010, respectively. See Note 5 Joint Interest Billings.

Inventories

Inventories consisted of $26.6 million and $25.2 million of materials and supplies and $6.4 million and $12.5 million of hydrocarbons as of September 30, 2011 and December 31, 2010, respectively. The Company s materials and supplies inventory primarily consists of casing and wellheads and is stated at the lower of cost, using the weighted average cost method, or market.

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

Exploration and Development Costs

The Company follows the successful efforts method of accounting for costs incurred in oil and natural gas exploration and production operations. Acquisition costs for proved and unproved properties are capitalized when incurred. Costs of unproved properties are transferred to proved properties when proved reserves are 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. 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.

The Company evaluates unproved property 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.

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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 three to seven years.

	Years Depreciated
Leasehold improvements	6
Office furniture, fixtures and computer equipment	3 to 7
Vehicles	5

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

Capitalized Interest

Interest costs from external borrowings are capitalized on major projects with an expected construction period of one year or longer. Capitalized interest is added to the cost of the underlying asset and is amortized over the useful lives of the assets 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 subsidiaries, Kosmos Energy Finance and Kosmos Energy Finance International, meet the definition of a VIE and the Company, which is the ultimate parent of both subsidiaries, is the primary beneficiary. Kosmos Energy Finance and Kosmos Energy Finance International are consolidated in these financial statements.

As of September 30, 2011 and December 31, 2010, Kosmos Energy Finance had zero and $58.0 million, respectively, in cash and cash equivalents. Kosmos Energy Finance did not have any assets or liabilities as of September 30, 2011, and will have no financial statement activity in the future. As of December 31, 2010, Kosmos Energy Finance s other assets and liabilities are shown separately on the face of the consolidated balance sheet in the following line items: current and long-term restricted cash; deferred financing costs; long-term derivatives asset; current and long-term debt; and current and long-term derivatives liabilities.

Prior to the incorporation of Kosmos Energy Finance International on March 18, 2011, Kosmos Energy Finance International did not have any financial statement activity. Kosmos Energy Finance International s assets and liabilities are shown separately on the face of the consolidated balance sheet as of September 30, 2011, in the following line items: current restricted cash; deferred financing costs; long-term debt; and current and long-term derivatives liabilities. At September 30, 2011, Kosmos Energy Finance International had $157.6 million in cash and cash equivalents, $7.5 million in accrued liabilities and $2.2 million in other long-term liabilities.

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Impairment of Long-lived Assets

The Company reviews its long-lived assets for impairment when changes in circumstances indicate that the carrying amount of an asset may not be recoverable. ASC 360 Property, Plant and Equipment requires an impairment loss to be recognized if the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. The carrying amount of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. That assessment shall be based on the carrying amount of the asset at the date it is tested for recoverability, whether in use or under development. An impairment loss shall be measured as the amount by which the carrying amount of a long-lived asset exceeds its fair value. 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 deferred premium puts and compound options (calls on puts). We also use interest rate swap contracts to mitigate our exposure to interest rate fluctuations related to our commercial debt facilities. Our derivative financial instruments are recorded on the balance sheet as either an asset or a liability 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 income in the period of change. See Note 10 Derivative Financial Instruments.

Estimates of Proved Oil and Natural Gas Reserves

Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion and 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 and the FASB. The accuracy of these reserve estimates is a function of:

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

- the judgments of the persons preparing the estimates.

Revenue Recognition

We use the sales method of accounting for oil and gas revenues. Under this method, we recognize revenues on the volumes sold. 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.

Stock-based Compensation

For stock-based compensation equity 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 (ii) a Monte Carlo simulation to determine the fair value of restricted stock awards with a combination of market and service vesting criteria.

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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. See Note 15 Income Taxes.

Foreign Currency Translation

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

Recent Accounting Standards

In May 2011, the FASB issued ASU No. 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs, to develop common requirements for valuation and disclosure of fair value measurements in accordance with U.S. GAAP and International Financial Reporting Standards. This ASU is effective for fiscal years and interim periods within those years beginning after December 15, 2011. We do not expect the adoption of this ASU will have a material effect on our consolidated financial statements.

In June 2011, the FASB issued ASU No. 2011-05, Presentation of Comprehensive Income, to improve the comparability, consistency and transparency of financial reporting and to increase the prominence of items reported in other comprehensive income. This ASU is effective for fiscal years and interim periods within those years beginning after December 15, 2011. We do not expect the adoption of this ASU will have a material effect on our consolidated financial statements.

3. Notes Receivable

Effective May 7, 2010, TGL, as operator of and acting on behalf of the Jubilee Unit parties under the Unitization and Unit Operating Agreement (Jubilee UUOA), entered into an Advance Payments Agreement (Advance Payments Agreement) with MODEC, Inc. (MODEC) related to partial funding of the construction of the FPSO. The payment limit for the Advance Payments Agreement is $466.3 million, of which Kosmos Energy Ghana HC s (Kosmos Ghana) a wholly owned subsidiary, share is $122.2 million. Of the $466.3 million, $341.1 million was deemed to have been advanced from TGL to MODEC. In September 2011, the maturity date of the Advance Payments Agreement was extended from September 15, 2011 to October 28, 2011 (see Note 18 Subsequent Events). MODEC is required to repay TGL on the earlier of the maturity date, or the date of the first drawdown under MODEC s long-term financing. The remaining balance due under the Advance Payments Agreement as of September 30, 2011 and December 31, 2010, was $109.4 million and $113.9 million, respectively. We recognized interest income of $1.5 million and zero for the three months ended September 30, 2011 and 2010, respectively, and $4.3 million and zero for the nine months ended

September 30, 2011 and 2010, respectively.

4. Jubilee Field Unitization

The Jubilee Field in Ghana, discovered by the Mahogany-1 well in June 2007, 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 and as required by Ghana s Ministry of Energy, it was agreed the Jubilee Field would be unitized for optimal resource recovery. Kosmos Ghana 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. On July 13, 2009, the Ministry of Energy provided its written approval of the Jubilee UUOA. The Jubilee UUOA was executed by all parties and was effective July 16, 2009. The tract participations were 50% for each block. TGL is the Unit Operator, and Kosmos Ghana is the Technical Operator for the development of the Jubilee Field. The accounting for the Jubilee Unit included in these consolidated financial statements is in accordance with the tract participation stated in the Jubilee UUOA. Pursuant to the terms of the Jubilee UUOA, the percentage of such interests 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% Unit Interest (participating interest in the Jubilee Unit) may call for a second redetermination after two years from December 1, 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 Note 5 Joint Interest Billings) to 24.07710%. The consolidated

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financial statements as of September 30, 2011, are based on these redetermined tract participations. As a result of the change in our Unit Interest, we recorded increases in oil and gas properties, inventory, notes receivable, current deferred tax asset and operator general and administrative expenses of $19.4 million, $3.9 million, $2.6 million, $0.2 million and $0.6 million, respectively, with an offsetting reduction of $14.2 million in JIB receivables and an increase of $12.5 million in long-term liabilities. Our capital costs due related to the increased Unit Interest are payable over a two-year period starting in December 2011. Although the Jubilee Field is unitized, Kosmos Ghana s working interest in each block outside the boundary of the Jubilee Unit area was not changed. Kosmos Ghana remains operator of the WCTP Block outside the Jubilee Unit area.

5. Joint Interest Billings

The Company s joint interest billings consist of receivables from partners with interests in common oil and gas properties operated by the Company. Joint interest billings are classified on the face of the consolidated balance sheets as current or long-term based on when collection is expected to occur. As of September 30, 2011 and December 31, 2010, we had $89.6 million and $124.4 million, respectively, included in current joint interest billings receivable and zero and $21.9 million, respectively, were included in long-term joint interest billings receivable. Long-term balances are shown net of allowances of zero and $39.8 million as of September 30, 2011 and December 31, 2010, respectively.

In August 2009, Ghana National Petroleum Corporation (GNPC) notified our unit partners and us that it would exercise its right for the applicable contractor group to pay its 2.5% WCTP Block share and 5.0% 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 WCTP Petroleum Agreement and DT Petroleum Agreement, respectively. As of September 30, 2011 and December 31, 2010, the joint interest billing receivable due from GNPC was $22.4 million and $29.6 million, respectively.

EO Group Limited s (EO Group) share of costs under the WCTP Petroleum Agreement until first production occurred were paid by Kosmos Ghana. EO Group was required to reimburse Kosmos Ghana for all development costs paid by Kosmos Ghana on EO Group s behalf. The related receivable became due upon commencement of production in 2010.

On July 22, 2011, Tullow Oil plc closed a transaction to acquire EO Group s entire 3.5% interest in the WCTP Petroleum Agreement, 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 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 unit 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 GNPC s additional paying interest of 3.75% in the Jubilee Unit. Our working interest in the remainder of the WCTP Block was not changed by the transaction and remains 30.875% (giving effect to GNPC s optional additional paying interest).

6. Property and Equipment

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

		September 30, 2011		December 31, 2010
		(In thousands)		
Oil and gas properties, net:				
Proved properties	$	562,363	$	426,831
Unproved properties		255,477		198,149
Support equipment and facilities		395,936		371,319
Less: accumulated depletion		(90,872)		(6,430)
	$	1,122,904	$	989,869

We recorded depletion expense of $41.3 million and zero for the three months ended September 30, 2011 and 2010, respectively, and $85.4 million and zero for the nine months ended September 30, 2011 and 2010, respectively. The Company had depletion costs of $5.5 million and $6.4 million included in crude oil inventory and other receivables as of September 30, 2011 and December 31, 2010, respectively.

7. Suspended Well Costs

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

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The following table reflects the Company s capitalized exploratory well activities as of and during the nine months ended September 30, 2011. The table excludes $48.0 million in costs that were capitalized and subsequently expensed in the same period.

	September 30, 2011 (In thousands)	
Beginning balance (January 1, 2011)	$	167,511
Additions to capitalized exploratory well costs pending the determination of proved reserves		114,717
Reclassification due to determination of proved reserves		
Capitalized exploratory well costs charged to expense		(39,868)
Ending balance (September 30, 2011)	$	242,360

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:

	September 30, 2011		December 31, 2010	
	(In thousands, except well counts)			
Exploratory well costs capitalized for a period of one year or less	$	108,673	$	49,022
Exploratory well costs capitalized for a period greater than one year		133,687		118,489
Ending balance	$	242,360	$	167,511
Number of projects with exploratory well costs that have been capitalized for more than one year		3		3

As of September 30, 2011, the exploratory well costs capitalized for more than one year since the completion of drilling are the Mahogany-3, Mahogany-4, Mahogany-5 and Mahogany Deep-2 exploration wells in the WCTP Block and the Tweneboa-1, Tweneboa-2 and Enyenra-1 wells in the DT Block. All costs incurred are approximately one to three years old.

Odum Discovery Due to the technical challenges presented by the gravity of the oil encountered in the Odum discovery, we determined to not declare the discovery commercial during the second quarter of 2011. Accordingly, the related suspended well costs associated with the Odum discovery of $32.6 million were written off.

Mahogany East Area Three appraisal wells, Mahogany-4, Mahogany-5 and Mahogany Deep-2, have been drilled. The Mahogany East Area was declared commercial in September 2010, and a plan of development (PoD) was submitted to Ghana s Ministry of Energy as of May 2, 2011. In a letter dated May 16, 2011, the Minister of Energy did not approve the PoD and requested the WCTP PA Block partners make separate declarations for the Mahogany extended area (east of the Jubilee Unit) and Mahogany deep discoveries, which were combined by the WCTP Block partners as Mahogany East in September 2010 and the PoD submission as of May 2, 2011; and requested other information. The WCTP PA partners believe the combined submission was proper and have held meetings with GNPC which resolved issues relating to the work program in the PoD. GNPC and the WCTP PA Block partners continued working to resolve other differences; however, the WCTP PA contains specific timelines for PoD approval and discussions, which expired at the end of June 2011. On June 30, 2011, we, as Operator of the WCTP Block and on behalf of the WCTP PA Block partners, delivered a Notice of Dispute to the Minister of Energy as provided under the WCTP PA. This Notice of Dispute establishes a process for negotiation and consultation for a period of 30 days (or longer if mutually agreed) among senior representatives from the Minister of Energy, GNPC and the WCTP PA Block partners to resolve the matter of approval of the PoD. We and the WCTP Block partners are in discussions with the Ministry of Energy and GNPC to resolve differences on the PoD.

Tweneboa Discovery Three appraisal wells, Tweneboa-2, Tweneboa-3 and Tweneboa-4, have been drilled. Following additional appraisal, drilling and evaluation, a decision regarding commerciality of the Tweneboa discovery is expected to be made by the DT block partners in 2012. Within six months of such a declaration, a plan of development would be prepared and submitted to Ghana s Ministry of Energy.

Enyenra Discovery Two appraisal wells, Enyenra-2A and Enyenra-3A, have been drilled. Following additional appraisal, drilling and evaluation, a decision regarding commerciality of the Enyenra discovery is expected to be made by the DT block partners in 2012. Within six months of such a declaration, a plan of development would be prepared and submitted to Ghana s Ministry of Energy.

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8. Accounts Payable and Accrued Liabilities

At September 30, 2011 and December 31, 2010, $197.2 million and $163.5 million, respectively, were recorded for invoices received but not paid. Accrued liabilities were $41.4 million and $53.2 million at September 30, 2011 and December 31, 2010, respectively, and consisted of the following:

	September 30, 2011	December 31, 2010
	(In thousands)	
Accrued liabilities:		
Accrued exploration and development	$ 15,917	$ 26,843
Accrued interest	7,484	655
Accrued general and administrative expenses	6,516	23,393
Taxes other than income	630	1,936
Income taxes	10,862	381
	$ 41,409	$ 53,208

9. Debt

In March 2011, the Company secured a $2.0 billion commercial debt facility (the Facility) from a number of financial institutions and extinguished the then existing commercial debt facilities. The Facility supports our oil and gas exploration, appraisal and development programs and corporate activities. The total loan commitments of the Facility may be increased up to a maximum of $3.0 billion if the lenders increase their commitments or if loan commitments from new financial institutions are added.

As part of the debt refinancing in March 2011, we recorded a $59.6 million loss on the extinguishment of debt. Additionally, we have $61.3 million of deferred financing costs related to the Facility, which are being amortized over the term of the Facility.

Interest expense was $9.3 million and $10.1 million (net of capitalized interest of $1.0 million and $3.0 million), and commitment fees were $2.2 million and $2.1 million for the three months ended September 30, 2011 and 2010, respectively. Interest expense was $36.6 million and $27.0 million (net of capitalized interest of $3.0 million and $7.1 million) and commitment fees were $5.7 million and $5.2 million for the nine months ended September 30, 2011 and 2010, respectively.

The 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). Kosmos pays commitment fees on the undrawn and unavailable portion of the total commitments. Commitment fees for the lenders 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. The Company recognizes 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 $1.0 million and $2.2 million of additional interest expense during the three and nine months ended September 30, 2011, respectively.

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

Kosmos has the right to cancel all the undrawn commitments under the Facility. The amount of funds available to be borrowed under the Facility, also known as the borrowing base amount, is determined each year on June 15 and December 15 as part of a forecast that is prepared by and agreed to by Kosmos 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. As of September 30, 2011, borrowings under the Facility totaled $1.0 billion. As of September 30, 2011, the undrawn availability under the Facility was an additional $407.3 million.

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.

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We were in compliance with the financial covenants contained in the Facility as of August 31, 2011, our most recent forecast date, which requires the maintenance of:

- the field life cover ratio, not less than 1.30x; and
- the loan life cover ratio, not less than 1.10x,

in each case, as calculated on the basis of all available information. 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 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. 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.

At September 30, 2011, the scheduled maturities of debt during the five year period and thereafter are as follows:

	Payments Due by Year (In thousands)					
	2011 (1)	**2012**	**2013**	**2014**	**2015**	**Thereafter**
Commercial debt facility(2)	$	$	$	$	$	$ 1,000,000

(1) Represents payments for the period October 1, 2011 through December 31, 2011.

(2) The scheduled maturities of debt are based on the level of borrowings and the available borrowing base as of September 30, 2011. 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 five year period and thereafter.

10. Derivative Financial Instruments

The Company uses 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.

The Company applies the provisions of ASC 815 Derivatives and Hedging, which requires each derivative instrument to be recorded in the balance sheet at fair value. If a derivative has not been designated as a hedge or does not otherwise qualify for hedge accounting, it must be adjusted to fair value through earnings. The Company does not apply hedge accounting treatment to its oil derivative contracts and, therefore, the changes in the fair values of these instruments are recognized in income in the period of change. These fair value changes, along with the cash settlements of expired contracts, are shown in our statement of operations.

Effective June 1, 2010, the Company discontinued hedge accounting on all interest rate derivative instruments. Therefore, the Company recognizes, from that date forward, changes in the fair value of the instruments in income 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(L)) in the equity section of the accompanying consolidated balance sheets, and are being transferred to earnings when the hedged transaction is recognized in earnings.

Oil Derivative Contracts

In 2010, we entered into various oil derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil production. These contracts consist of deferred premium puts and compound options (calls on puts).

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

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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 September 30, 2011:

Type of Contract and Period	bbl/day		Weighted Average Floor Price		Weighted Average Deferred Premium/bbl
Deferred Premium Puts					
October 2011 - December 2011	11,332	$	72.01	$	9.12
January 2012 - December 2012	4,625		62.74		7.04
January 2013 - December 2013	2,515		61.73		7.32
Compound Options (calls on puts)					
July 2012 - December 2012(1)	5,399		66.48		6.73
January 2013 - June 2013(1)	3,855		66.48		7.10

(1) The calls expire June 29, 2012, and have a weighted average premium of $4.82/bbl.

Interest Rate Swaps Derivative Contracts

In 2010, Kosmos entered into derivative instruments in the form of interest rate swaps, which hedge risk related to interest rate fluctuation, whereby it converts the interest due on certain floating rate debt to a weighted average fixed rate. The following table summarizes our open interest rate swaps as of September 30, 2011:

Termination Date		Notional Amount (In thousands)	Fixed Rate	Floating Rate
June 2014	$	77,500	0.98%	6-month LIBOR
June 2015		75,007	1.34%	6-month LIBOR
June 2016		161,250	2.22%	6-month LIBOR
June 2016		161,250	2.31%	6-month LIBOR

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

The following tables disclose the Company s derivative instruments as of September 30, 2011 and December 31, 2010:

	Estimated Fair Value Asset (Liability)	
	September 30,	December 31,

Type of Contract	Balance Sheet Location	2011	2010
		(In thousands)	
Derivatives not designated as hedging instruments:			
Derivative asset:			
Commodity	Derivatives assets - current	$	$
Interest rate	Derivatives assets - current		
Commodity	Derivatives assets - noncurrent		
Interest rate	Derivatives assets - noncurrent		1,501
Derivative liability:			
Commodity	Derivatives liabilities - current	(22,812)	(13,979)
Interest rate	Derivatives liabilities - current	(7,211)	(6,375)
Commodity	Derivatives liabilities - long-term	(4,784)	(14,340)
Interest rate	Derivatives liabilities - long-term	(4,890)	(764)
Total derivatives not designated as hedging instruments		$ (39,697)	$ (33,957)

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Type of Contract	Location of Gain/(Loss)	Amount of Gain/(Loss) Three Months Ended September 30, 2011	Amount of Gain/(Loss) Three Months Ended September 30, 2010	Amount of Gain/(Loss) Nine Months Ended September 30, 2011	Amount of Gain/(Loss) Nine Months Ended September 30, 2010
		(In thousands)			
Derivatives in cash flow hedging relationships:					
Interest rate	AOCI(L)	$	$	$	$ (455)
Interest rate(1)	Interest expense	(1,193)	(1,278)	(2,934)	(4,383)
Total derivatives in cash flow hedging relationships		$ (1,193)	$ (1,278)	$ (2,934)	$ (4,838)
Derivatives not designated as hedging instruments:					
Commodity	Derivatives, net	$ 4,984	$ (10,339)	$ (5,250)	$ (15,310)
Interest rate	Interest expense	(3,921)	(5,715)	(9,933)	(9,079)
Total derivatives not designated as hedging instruments		$ 1,063	$ (16,054)	$ (15,183)	$ (24,389)

(1) Amounts were reclassified from AOCI(L) into earnings.

The fair value of the effective portion of the derivative contracts on May 31, 2010, is reflected in AOCI(L) and is being transferred to interest expense over the remaining term of the contracts. In accordance with the mark-to-market method of accounting, the Company recognizes all future changes in fair values of its derivative contracts as gains or losses in earnings during the period in which they occur. The Company expects to reclassify $0.2 million of losses from AOCI(L) to interest expense within the next 12 months. See Note 11 Fair Value Measurements for additional information regarding the Company s derivative instruments.

11. Fair Value Measurements

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

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

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

• 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.

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The following tables present the Company s assets and liabilities that are measured at fair value on a recurring basis as of September 30, 2011 and December 31, 2010, 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)		
September 30, 2011				
Assets:				
Money market accounts	$ 475,941	$	$	$ 475,941
Interest rate derivatives				
Liabilities:				
Commodity derivatives		(27,596)		(27,596)
Interest rate derivatives		(12,101)		(12,101)
Total	$ 475,941	$ (39,697)	$	$ 436,244
December 31, 2010				
Assets:				
Money market accounts	$ 18,056	$	$	$ 18,056
Interest rate derivatives		1,501		1,501
Liabilities:				
Commodity derivatives		(28,319)		(28,319)
Interest rate derivatives		(7,139)		(7,139)
Total	$ 18,056	$ (33,957)	$	$ (15,901)

All fair values have been adjusted for nonperformance risk resulting in a decrease of the commodity derivative liabilities of approximately $0.8 million and a decrease of the interest rate derivatives of approximately of $0.4 million as of September 30, 2011. When the accumulated net present value for all of the derivative contracts with a counterparty is in an asset position, the Company uses the counterparty s credit default swap (CDS) rates to estimate non-performance risk. When the accumulated net present value for all derivative contracts for a counterparty are in a liability position, the Company uses its internal rate of borrowing to estimate our non-performance risk.

The book values of cash and cash equivalents, joint interest billings, notes 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 the Company for those periods. The Company s long-term receivables after allowance approximate fair value.

Commodity Derivatives

The Company s commodity derivatives represent crude oil deferred premium puts and compound options for notional barrels of oil at fixed Dated Brent oil prices. The values attributable to the Company s oil derivatives are based on (i) the contracted notional volumes, (ii) independent active futures price quotes for Dated Brent, (iii) a credit-adjusted yield curve applicable to each counterparty by reference to the CDS market and (iv) an independently sourced estimate of volatility for Dated Brent. The volatility estimate was provided by certain independent brokers who are active in buying and selling oil options and was corroborated by market-quoted volatility factors. The deferred premium is included in the fair market value of the puts and compound options. The Company s commodity derivative liability measurements represent Level 2 inputs in the hierarchy priority. See Note 10 Derivative Financial Instruments for additional information regarding the Company s derivative instruments.

Interest Rate Derivatives

As of September 30, 2011 and December 31, 2010 the Company had interest rate swaps with notional amounts of $475.0 million, whereby the Company pays a fixed rate of interest and the counterparty pays a variable LIBOR-based rate. The values attributable to the Company s interest rate derivative contracts are based on (i) the contracted notional amounts, (ii) LIBOR yield curves provided by independent third parties and corroborated with forward active market-quoted LIBOR yield curves and (iii) a credit-adjusted yield curve as applicable to each counterparty by reference to the CDS market. The Company s interest rate derivative asset and liability measurements represent Level 2 inputs in the hierarchy priority.

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12. Asset Retirement Obligations

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

		September 30, 2011 (In thousands)
Asset retirement obligations:		
Beginning asset retirement obligations	$	16,752
Liabilities incurred during period		1,257
Revisions in estimated retirement obligations		
Liabilities settled during period		
Accretion expense		1,613
Ending asset retirement obligations	$	19,622

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, issued to TGL, a decommissioning plan will be prepared and submitted to the Ghana Environmental Protection Agency. ASC 410 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, including wells in progress in such fields. Additional asset retirement obligations will be recorded in the period in which wells within such producing fields are commissioned.

13. Convertible Preferred Units

Contemporaneous with Kosmos Energy Ltd. s initial public offering, the Series A Convertible Preferred Units (Series A Units), Series B Convertible Preferred Units (Series B Units) and Series C Convertible Preferred Units (Series C Units) of Kosmos Energy Holdings were exchanged into our common shares based on the pre-offering equity value of such interests. This resulted in the Series A, Series B and Series C Convertible Preferred Units being exchanged into 163,048,228; 109,837,843; and 4,811,757 common shares of Kosmos Energy Ltd., respectively, or 277,697,828 common shares in the aggregate. The common shares have one vote per share and a par value of $0.01. The exchange of the Convertible Preferred Units had the effect of increasing the book value of shareholders equity by approximately $1.0 billion. Accretion to redemption value of the Convertible Preferred Units was recorded through the date of the exchange. After the date of the exchange, the related accretion on the Convertible Preferred Units ceased to accrue and all rights of the holders with respect to the Convertible Preferred Units terminated, except for the right to receive shares of common stock issuable upon the exchange and the rights entitled to a holder of a common share.

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

14. Equity-based Compensation

Profit Units

Prior to our corporate reorganization, Kosmos Energy Holdings issued common units designated as profit units with a threshold value of $0.85 to $90 to employees, management and directors. Profit units, the defined term in the related agreements, are equity awards that are 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

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units issued to employees vested 50% on the second and fourth anniversary of the issuance date. Of the 100 million authorized common units, 15.7 million were designated as profit units.

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

	Profit Units (In thousands)	Weighted-Average Grant-Date Fair Value
Outstanding at December 31, 2009	13,507	$ 0.81
Granted	411	5.27
Relinquished	(8)	2.45
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 (In thousands)	Weighted-Average Grant-Date Fair Value
Outstanding at December 31, 2009	6,957	$ 1.06
Granted	411	5.27
Vested	(2,719)	1.03
Relinquished	(8)	2.45
Accelerated vesting	(1,177)	10.66
Outstanding at December 31, 2010	3,464	1.60
Granted	1,783	15.71
Vested	(1,066)	1.09
Relinquished	(1,253)	0.10
Outstanding at May 16, 2011	2,928	11.02

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

Total profit unit compensation expense recognized in income was zero and $0.4 million for the three months ended September 30, 2011 and 2010, respectively, and $1.2 million and $1.7 million for the nine months ended September 30, 2011 and 2010, respectively.

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

Restricted Stock Awards

As part of the corporate reorganization, vested profit units were exchanged for 31,689,689 common shares of Kosmos Energy Ltd., unvested profit units were exchanged for 10,032,827 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

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award types. The LTIP provides for the issuance of 24.5 million shares pursuant to awards under the plan, in addition to the 10,032,827 restricted stock awards exchanged for unvested profit units.

The following table shows the number of shares available for issuance pursuant to awards under the Company s LTIP at September 30, 2011:

	Shares (In thousands)
Approved and authorized awards(1)	24,503
Awards issued after May 16, 2011(1)	(14,520)
Awards forfeited(1)	95
Awards available for future grant	10,078

(1) Excludes 10,032,827 restricted stock awards that were exchanged for unvested profit units and any related forfeitures of such awards.

The Company records compensation expense equal to the fair value of share-based payments over the vesting periods of the LTIP awards. The Company recorded $20.1 million and $28.1 million in compensation expense from our restricted stock awards during the three and nine months ended September 30, 2011. The following table reflects the outstanding restricted stock awards as of September 30, 2011:

	Restricted Shares (In thousands)	**Weighted-Average Grant-Date Fair Value**
Outstanding at May 16, 2011		$
Exchanged	10,033	2.79
Granted	14,520	17.11
Forfeited	(646)	3.43
Vested	(3,382)	0.38
Outstanding at September 30, 2011	20,525	13.30

During 2011, the Company granted restricted stock awards with service vesting criteria and awards with a combination of market and service vesting criteria under the LTIP. For stock-based compensation equity 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 (ii) a Monte Carlo simulation to determine the fair value of restricted stock awards with a combination of market and service vesting criteria.

For awards with a combination of market and service vesting criteria, the number of shares of common stock 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. The grant date fair value was estimated to be $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 of 41.25% utilized in the model was estimated using historical volatilities of our peer companies. The risk-free interest rate of 1.08% was based on the U.S. treasury rate for a term commensurate with the expected life of the grant.

15. Income Taxes

The income tax provision (benefit) was $50.5 million and nil for the three months ended September 30, 2011 and 2010, respectively, and was $48.5 million and $(0.2) million for the nine months ended September 30, 2011 and 2010, respectively. The income tax provision consists of U.S. and Ghanaian income and Texas margin taxes.

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

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
United States	$ 3,430	$ 536	$ 4,239	$ 617
Ghana	141,401	(24,927)	134,856	(86,965)
Other foreign jurisdictions	(42,574)	(58,164)	(102,556)	(94,064)
Ending balance	$ 102,257	$ (82,555)	$ 36,539	$ (180,412)

Our effective tax rate for the three months ended September 30, 2011 and 2010 was 49% and 1%, respectively. For the, nine months ended September 30, 2011 and 2010 our effective tax rate was 133% and 1%. The effective tax rate for the United States and Ghana is approximately 35% for all periods presented, while the effective tax rate for our other foreign jurisdictions is 0%. Our other foreign jurisdictions have a 0% effective tax rate because they reside in countries with a 0% statutory rate, or they have a full valuation allowance reserved against their ending net related deferred tax asset.

The Company s Ghanaian deferred tax asset was $30.3 million and $77.5 million as of September 30, 2011 and December 31, 2010, respectively. The Company considered the following positive evidence to conclude that our Ghanaian deferred tax asset as of September 30, 2011 and December 31, 2010 would be recognized in the future:

- The commencement of oil production on November 28, 2010. Equipment and infrastructure was fully in place in the fourth quarter of 2010 immediately prior to production commencing, and the November 2010 successful commencement of production confirmed our expectations that these assets could be utilized to successfully produce from the field with an economical cost structure.

- The recognition of our first revenues from oil production in January 2011. The Company was a development stage entity as of December 31, 2010, but upon recognition of our first revenues in January 2011, is no longer categorized as such.

- The existence of significant proved reserves that have been independently verified.

- The Company produces a commodity (crude oil) with observable market demand capable of purchasing all barrels produced. Prices for oil can be estimated through forward pricing curves.

- The excess of appreciated asset value over the tax basis of our Ghanaian net assets of an amount sufficient to realize the deferred tax asset. Our estimates of the excess of the appreciated asset value were based upon the independently verified reserve report, third-party offers for our Ghanaian assets, and other market indicators.

- There is an unlimited net operating loss carryforward period under Ghanaian tax law, which provides flexibility in utilization of the net operating loss.

The Company has no material unrecognized income tax benefits.

A subsidiary of the Company files a U.S. federal income tax return and a Texas margin tax return. In addition, the Company files income tax returns in the countries in which it operates. The Company is open to U.S. federal income tax examinations for tax years 2008 through 2010 and to foreign income tax examinations for the tax years 2004 through 2010. In addition, the Company is open to Texas tax examinations for the tax years 2006 through 2010.

The Company s policy is to recognize probable interest and penalties related to income tax matters in income tax expense, but has had no need to accrue any to date.

16. Net Income (Loss) Per Share

In the calculation of basic net income (loss) 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. The Company s participating securities 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

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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.

Pro forma net income (loss) attributable to common shares reflects net income (loss) as reported and gives effect to an adjustment to remove accretion on the Convertible Preferred Units. In our pro forma basic and diluted income (loss) per share attributable to common shareholders calculation, we assumed the conversion of the Convertible Preferred Units occurred on January 1, 2011 and, therefore, we have removed the related accretion to determine pro forma net income (loss).

Pro forma weighted average common shares outstanding used in the computation of pro forma basic and diluted income (loss) per share attributable to common shareholders has been computed taking into account (1) the conversion ratio at the time of the initial public offering of all common units and Convertible Preferred Units into common shares as if the conversion occurred as of the beginning of the year and (2) the 34,518,242 common shares issued by the Company in the initial public offering, which included 1,518,242 common shares issued pursuant to the over-allotment option exercised by the underwriters of the initial public offering.

The following table is a reconciliation of the Company s net income (loss) attributable to common shareholders to basic net income (loss) attributable to common shareholders and to diluted net income (loss) attributable to common shareholders and a reconciliation of basic weighted average common shares outstanding to diluted weighted average common shares outstanding for the three and nine months ended September 30, 2011:

	Three Months Ended September 30,		Nine Month Ended September 30,	
(In thousands, except per share data)	**2011**	**2010**	**2011**	**2010**
Numerator:				
Net income (loss) attributable to common shareholders	$ 51,776	N/A	$ (36,408)	N/A
Less: Basic income allocable to participating securities(1)	2,349	N/A		N/A
Basic net income (loss) attributable to common shareholders	49,427	N/A		
Plus: Accretion to redemption value of convertible preferred units			24,442	N/A
Pro forma basic net income (loss) attributable to common shareholders			(11,966)	N/A
Diluted adjustments to income allocable to participating securities(1)	3	N/A		N/A
Diluted net income (loss) attributable to common shareholders	$ 49,430	N/A		

Pro forma diluted net income (loss) attributable to common shareholders				$	(11,966)	N/A
Denominator:						
Weighted average number of shares used to compute net income (loss) per share:						
Basic		368,996	N/A			
Restricted stock awards(1)(2)		345	N/A			
Diluted		369,341	N/A			
Pro forma basic					349,792	N/A
Pro forma restricted stock awards(1)(2)						N/A
Pro forma diluted					349,792	N/A
Net income (loss) per share attributable to common shareholders:						
Basic	$	0.13	N/A			
Diluted	$	0.13	N/A			
Pro forma basic				$	(0.03)	N/A
Pro forma diluted				$	(0.03)	N/A

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(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 are not considered to be participating securities and, therefore, are excluded from the basic net income (loss) per common share calculation. Restricted stock awards do not participate in undistributed net losses.

(2) Due to our basic net loss attributable to common shareholders for the nine months ended September 30, 2011, we excluded 13.6 million outstanding restricted stock awards from the computations of pro forma diluted net loss per share because the effect would have been anti-dilutive. For the three months ended September 30, 2011, we excluded 5.5 million outstanding restricted stock awards from the computations of diluted net income per share because the effect would have been anti-dilutive.

17. Commitments and Contingencies

On June 23, 2008, Kosmos Ghana signed an offshore drilling contract with Alpha Offshore Drilling Services Company, a wholly owned subsidiary of Atwood Oceanics, Inc., for the semi-submersible drilling rig Atwood Hunter. Noble Energy EG Ltd. (Noble) also is a party to the contract. The initial rig rate was $538 thousand per day and is subject to annual adjustments for cost increases. Effective, July 27, 2009 and 2010, the rig rate was adjusted to $543 thousand per day and $546 thousand per day, respectively. The contract, as amended, is for 1,152 days, with Kosmos Ghana and Noble allotted 797 days and 355 days, respectively. Kosmos Ghana and TGL entered into a rig and services sharing agreement on October 18, 2009, for use of the Atwood Hunter on the WCTP and DT Blocks during part of Kosmos Ghana s allocated rig time. The future minimum commitments under this contract as of September 30, 2011, are: 2011 zero; and 2012 $136.4 million.

18. Subsequent Events

Notes Receivable

In October 2011, the maturity date under the Advance Payments Agreement with MODEC, related to partial funding of the construction of the FPSO, was extended to November 28, 2011. The terms and conditions existing in the Advance Payments Agreement remain in effect through the maturity date.

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Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with our consolidated financial statements and notes thereto contained herein and our annual financial statements for the year ended December 31, 2010, included in our final prospectus along with the section Management s Discussion and Analysis of financial condition and Results of Operations contained in such final prospectus. Any terms used but not defined in the following discussion have the same meaning given to them in the final prospectus. Our discussion and analysis includes forward-looking information that involves risks and uncertainties and should be read in conjunction with Risk Factors under Item 1A of this report and in the final prospectus, along with Forward-Looking Information at the end of this section for information about the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

Overview

We are an independent oil and gas exploration and production company focused on underexplored regions in Africa. Our current asset portfolio includes world-class discoveries and partially de-risked exploration prospects offshore the Republic of Ghana, as well as exploration licenses with significant hydrocarbon potential onshore the Republic of Cameroon and offshore the Kingdom of Morocco. This portfolio, assembled by our experienced management and technical teams, provides investors with differentiated access to both high-impact exploration opportunities as well as defined, multi-year visibility in the reserve and production growth of our existing discoveries.

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 initial public offering on May 16, 2011, all of the interests in Kosmos Energy Holdings were exchanged for newly issued common shares of Kosmos Energy Ltd. As a result, Kosmos Energy Holdings became wholly owned by Kosmos Energy Ltd.

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

Third Quarter 2011 Highlights

Ghana Jubilee Field

During the third quarter of 2011, we had two liftings of oil totaling 1,994 Mbbls from our Jubilee Field Phase 1 production resulting in revenues of $230.3 million. Our average realized price per barrel was $115.50.

A total of 17 development wells have been drilled during Jubilee Field Phase 1 development. Currently, 16 wells are on-line with one sidetrack on an existing well being performed.

The Phase I PoD addendum has been submitted to the Ministry of Energy and GNPC. The Phase I addendum includes eight additional wells to be drilled beginning in 2012, of which five will be producers and three will be injectors.

Ghana exploration and appraisal activity

The Teak-3 appraisal well was spud in October 2011. This appraisal well is expected to reach its target depth in the fourth quarter of 2011.

In August 2011, we announced the Akasa-1 exploration well had made a hydrocarbon discovery on the WCTP Block. Analysis of well results, including wireline logs, reservoir pressures and fluid samples, confirmed that the well penetrated 33 meters (108 feet) of oil-bearing pay in four good-quality Turonian-aged sand packages.

In September 2011, the Enyenra-3A appraisal well confirmed an updip extension of the Enyenra light oil field on the DT Block. Analysis of well results, including wireline logs, reservoir pressures and fluid samples indicated the Enyenra-3A well encountered 17 meters (56 feet) of oil-bearing pay.

In July 2011, the Company announced the plans to drill an additional exploratory well, the Cedrela-1 in the WCTP Block. Prior to the commencement of drilling operations, the Transocean Marianas rig to be used for drilling the well was rendered temporarily inoperable due to an incident that could not be foreseen on an adjacent block offshore Ghana while under contract to another company. This resulted in the delay in the rig s scheduled arrival at the Cedrela-1 well location while undergoing repairs in Ghanaian waters. As a result of this unforeseen delay in the drilling of the Cedrela-1 well, the Company, as Operator for the WCTP PA Block partners, delivered a Force Majeure notice under the WCTP PA to the Ministry of Energy and GNPC on July 7, 2011. The

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Ministry of Energy and GNPC have not agreed this event is Force Majeure; however, we are attempting to resolve this. On August 24, 2011, we, as Operator of the WCTP Block and on behalf of the WCTP PA Block partners, delivered a Notice of Dispute to the Ministry of Energy as provided under the WCTP PA. Given the ongoing dispute, we intend to drill the Cedrela-1 well when we resolve this matter with the Ministry of Energy and GNPC.

The seven-year exploration phase of the WCTP PA expired on July 21, 2011. We and our WCTP PA Block partners have a right to negotiate a new petroleum agreement with respect to undeveloped parts of the WCTP Block that would otherwise be relinquished under the WCTP PA; that is acreage not within a discovery area, development and production area or the Jubilee Unit (Relinquishment Area). We and our WCTP PA Block partners exercised such right in July 2010 and formally submitted a proposed new petroleum agreement for the Relinquishment Area in early 2011. We and our partners, GNPC and the Ghana Ministry of Energy have agreed such WCTP PA rights will be extended (from July 21, 2011). During such extension, it is intended that the new petroleum agreement will be negotiated and GNPC will solicit third party offers for the Relinquishment Area. We and our WCTP PA Block partners have a right to match any such bona fide third party offers. If we are unsuccessful in negotiating a new petroleum agreement for the Relinquishment Area or decide not to match any bone fide third party offers, the identified prospects within the Relinquishment Area of the WCTP Block will not be drilled by us.

Pursuant to the terms of the Jubilee UUOA, the unit participation interests 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% Unit Interest may call for a second redetermination after two years from December 1, 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) to 24.07710%.

In October 2011, the maturity date under the Advance Payments Agreement with MODEC, related to partial funding of the construction of the FPSO, was extended to November 28, 2011. The terms and conditions existing in the Advance Payments Agreement remain in effect through the maturity date.

Morocco

During the third quarter of 2011, the Company continued to increase our acreage positions offshore the Kingdom of Morocco.

The Company entered into a Petroleum Agreement, which became effective in July 2011, with the Office National des Hydrocarbures et des Mines (ONHYM), the national oil company of Morocco, covering the Foum Assaka area offshore the Kingdom of Morocco. The Company has a 37.5% participating interest in the agreement, with ONHYM having a 25% participating interest and Pathfinder Hydrocarbon Ventures Limited holding the remaining 37.5% participating interest. ONHYM s 25% participating interest will be carried through the exploration phase. The Company is the operator.

In July 2011, the Company entered into a Petroleum Agreement with ONHYM, covering the Cap Boujdour area offshore the Kingdom of Morocco. The agreement will become effective upon publication of a ministerial order in accordance with Moroccan law; which we anticipate occurring during the fourth quarter of 2011. The signed agreement calls for the Company to have a 75% participating interest in the agreement, with ONHYM having a 25% participating interest. ONHYM s 25% participating interest will be carried through the exploration phase. The

Company is the operator.

In September 2011, the Company entered into a Petroleum Agreement with ONHYM and Canamens Energy Morocco SARL (Canamens) covering the Essaouira area offshore the Kingdom of Morocco. The agreement will become effective upon publication of a ministerial order in accordance with Moroccan law; which we anticipate occurring during the fourth quarter of 2011. The signed agreement calls for the Company and Canamens to each have a 37.5% participating interest in the agreement, with ONHYM having a 25% participating interest. ONHYM s 25% participating interest will be carried through the exploration phase. The Company is the operator.

Cameroon

The current exploration phase of the Kombe-N sepe license was scheduled to end June 30, 2011, while the N gata-1 well was drilling. The Establishment Convention governing the Kombe-N sepe license provides for a six month extension of the term for evaluation of the results of the well that is in progress at the end of the license period to perform necessary technical evaluation. The operator of the block exercised this right by applying for the six month extension to the exploration phase of the Kombe-N sepe license.

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Results of Operations

Certain operating results and statistics for the comparative third quarters of 2011 and 2010 are included in the following table:

	Three Months Ended September 30		Nine Months Ended September 30,	
(In thousands, except per barrel data)	**2011**	**2010**	**2011**	**2010**
Sales volumes:				
Mbbls	1,994		3,979	
Revenues:				
Oil sales	$ 230,262	$	$ 446,914	$
Average sales price per bbl	115.50		112.32	
Costs:				
Oil production	$ 24,185	$	$ 58,481	$
Depletion	41,297		85,393	
Average oil production cost per bbl	12.13		14.70	
Average depletion cost per bbl	20.71		21.46	
Average oil production cost and depletion per bbl	$ 32.84	$	$ 36.16	$

The following table shows the number of wells in the process of drilling or in active completion stages, and the number of wells suspended or awaiting completion as of September 30, 2011:

	Wells in the Process of Drilling or in Active Completion				Wells Suspended or Awaiting Completion			
	Exploration		Development		Exploration		Development	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Ghana								
West Cape Three Points					8	2.47		
Deepwater Tano	1	0.18			6	1.08		
Jubilee Unit			1	0.24				

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

Three months ended September 30, 2011 compared to three months ended September 30, 2010

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Increase (Decrease)
		(In thousands)	
Revenues and other income:			
Oil and gas revenue	$ 230,262	$	$ 230,262
Interest income	2,492	675	1,817
Other income	91	1,313	(1,222)
Total revenues and other income	232,845	1,988	230,857
Costs and expenses:			
Oil and gas production	24,185		24,185
Exploration expenses, including dry holes	11,005	18,960	(7,955)
General and administrative	39,093	27,845	11,248
Depletion and depreciation	42,593	578	42,015
Amortization deferred financing costs	2,194	7,644	(5,450)
Interest expense	16,581	19,146	(2,565)
Derivatives, net	(4,984)	10,339	(15,323)
Other expenses, net	(79)	31	(110)
Total costs and expenses	130,588	84,543	46,045
Income (loss) before income taxes	102,257	(82,555)	184,812
Income tax expense (benefit)	50,481	(6)	50,487
Net income (loss)	$ 51,776	$ (82,549)	$ 134,325

Oil and gas revenue. During the three months ended September 30, 2011, we recorded oil and gas revenue of $230.3 million due to our liftings of oil from our Jubilee Field Phase 1 production. We lifted and sold approximately 1,994 Mbbls at an average realized price per barrel of $115.50. In 2010, there were no liftings of oil and, therefore, no associated revenues.

Oil and gas production. During the three months ended September 30, 2011, we recorded oil and gas production costs of $24.2 million associated with our liftings of oil from our Jubilee Field Phase 1 production. Our average production cost per barrel was $12.13. In 2010, there were no liftings of oil and, therefore, no associated oil and gas production costs.

Exploration expenses. Exploration expenses decreased $8.0 million during the three months ended September 30, 2011, as compared with the three months ended September 30, 2010. During the three months ended September 30, 2011, we incurred $4.5 million of unsuccessful well costs, primarily related to the Ghana Makore-1 and Cameroon N gata-1 exploration wells and $5.8 million for seismic costs. During the three months ended September 30, 2010, the Company incurred $15.7 million of unsuccessful well costs primarily related to the Cameroon Mombe-1 and Ghana Onyina-1 exploration wells and $3.1 million for seismic costs.

General and administrative. General and administrative costs increased $11.2 million during the three months ended September 30, 2011, as compared with the three months ended September 30, 2010, primarily due to increases in non-cash expenses for equity-based compensation and an increase in headcount, partially offset by decreases in professional fees and expenses. Total non-cash general and administrative costs were $20.1 million and $0.4 million for the three months ended September 30, 2011 and 2010, respectively.

Depletion and depreciation. Depletion and depreciation increased $42.0 million during the three months ended September 30, 2011, as compared with the three months ended September 30, 2010, primarily due to the liftings of oil from our Jubilee Field Phase 1 production. In 2010, there were no liftings of oil and, therefore, no associated depletion.

Amortization deferred financing costs. In March 2011, we refinanced our existing commercial debt facilities. As part of the transaction, we incurred $52.3 million of deferred financing costs, in addition to 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 will be amortized over the term of the Facility. The related amortization of deferred financing costs decreased by $5.5 million during the three months ended September 30, 2011, as compared to the three months ended September 30, 2010, due to the decrease in capitalized deferred financing costs and the longer term associated with the Facility.

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Interest expense. Interest expense decreased $2.6 million during the three months ended September 30, 2011, as compared with the three months ended September 30, 2010, primarily due to a lower average interest rate for the three months ended September 30, 2011.

Derivatives, net. Derivatives, net decreased $15.3 million during the three months ended September 30, 2011, as compared with September 30, 2010 due to the change in fair value of the commodity derivative instruments.

Income tax expense (benefit). Income tax expense was $50.5 million during the three months ended September 30, 2011, as compared to an income tax benefit of nil for the three months ended September 30, 2010. During the three months ended September 30, 2011, we had net income from our Ghanaian subsidiary that generated an income tax expense. During the three months ended September 30, 2010, we had a net loss that generated an income tax benefit; however, the related deferred tax assets that were generated from the net loss had a 100% valuation allowance.

Nine months ended September 30, 2011 compared to nine months ended September 30, 2010

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010 (In thousands)	Increase (Decrease)
Revenues and other income:			
Oil and gas revenue	$ 446,914	$	$ 446,914
Interest income	7,459	2,548	4,911
Other income	735	3,793	(3,058)
Total revenues and other income	455,108	6,341	448,767
Costs and expenses:			
Oil and gas production	58,481		58,481
Exploration expenses, including dry holes	104,657	52,764	51,893
General and administrative	72,140	50,804	21,336
Depletion and depreciation	88,960	1,655	87,305
Amortization deferred financing costs	13,999	20,555	(6,556)
Interest expense	55,239	45,645	9,594
Derivatives, net	5,250	15,310	(10,060)
Loss on extinguishment of debt	59,643		59,643
Doubtful accounts expense	(39,782)		(39,782)
Other expenses, net	(18)	20	(38)
Total costs and expenses	418,569	186,753	231,816
Income (loss) before income taxes	36,539	(180,412)	216,951
Income tax expense (benefit)	48,505	(174)	48,679
Net loss	$ (11,966)	$ (180,238)	$ 168,272

Oil and gas revenue. During the nine months ended September 30, 2011, we recorded oil and gas revenue of $446.9 million due to oil production from our Jubilee Field Phase 1 production. We lifted and sold approximately 3,979 Mbbls at an average realized price per barrel of $112.32. In 2010, there were no liftings of oil and, therefore, no associated revenues.

Oil and gas production. During the nine months ended September 30, 2011, we recorded oil and gas production costs of $58.5 million related to oil production from our Jubilee Field Phase 1 development. Our average production cost per barrel was $14.70. In 2010, there were no liftings of oil and, therefore, no associated oil and gas production costs.

Exploration expenses. Exploration expenses increased $51.9 million during the nine months ended September 30, 2011, as compared with the nine months ended September 30, 2010. During the nine months ended September 30, 2011, we incurred $15.9 million for seismic costs for Ghana, Cameroon and new ventures and $87.8 million of unsuccessful well costs, primarily related to the Cameroon N gata-1, Ghana Makore-1, Ghana Banda-1 and Ghana Odum exploration wells. During the nine months ended September 30, 2010, the Company incurred $43.1 million of unsuccessful well costs primarily related to the Ghana Dahoma-1 and Cameroon Mombe-1 wells and $9.1 million for seismic costs primarily for Cameroon and Ghana.

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General and administrative. General and administrative costs increased $21.3 million during the nine months ended September 30, 2011, as compared with the nine months ended September 30, 2010, due to increases in non-cash expenses of $27.6 million for equity-based compensation and an increase in headcount, partially offset by decreases in cash expenses for professional fees and expenses. Total non-cash general and administrative costs were $29.3 million and $1.7 million for the nine months ended September 30, 2011 and 2010, respectively.

Depletion and depreciation. Depletion and depreciation increased $87.3 million during the nine months ended September 30, 2011, as compared with the nine months ended September 30, 2010, due to production from our Jubilee Field Phase 1 development. In 2010, there were no liftings of oil and, therefore, no associated depletion.

Amortization deferred financing costs and *Loss on extinguishment of debt.* During the nine months ended September 30, 2011, we incurred approximately $52.3 million of deferred financing costs as part of our debt refinance, in addition to our existing unamortized deferred financing costs of $68.6 million. As a result of the debt refinance, we recorded a $59.6 million loss on the extinguishment of debt. The remaining costs were capitalized and will be amortized over the term of the Facility. The related amortization of deferred financing costs decreased by $6.6 million during the nine months ended September 30, 2011, as compared to the nine months ended September 30, 2010, due to the decrease in capitalized deferred financing costs and the longer term associated with the new Facility.

Interest expense. Interest expense increased $9.6 million during the nine months ended September 30, 2011, as compared with the nine months ended September 30, 2010, primarily due to higher average outstanding debt and a decrease in capitalized interest during the nine months ended September 30, 2011.

Derivatives, net. Derivatives, net decreased $10.1 million during the nine months ended September 30, 2011, as compared with September 30, 2010 due to the change in fair value of the commodity derivative instruments.

Income tax benefit. Income tax expense was $48.5 million during the nine months ended September 30, 2011, as compared to an income tax benefit of $0.2 million for the nine months ended September 30, 2010. During the nine months ended September 30, 2011, we had net income from our Ghanaian subsidiary that generated an income tax expense. During the nine months ended September 30, 2010, we had a net loss that generated an income tax benefit; however, the related deferred tax assets that were generated from the net loss had a 100% valuation allowance.

Liquidity and Capital Resources

We are actively engaged in an ongoing process to anticipate and meet our funding requirements related to exploring for and developing oil and natural gas resources in Africa. We have historically secured funding from equity commitments and commercial debt facilities to meet our ongoing liquidity requirements. In addition, we received our first oil revenues in January 2011 from Jubilee Field Phase 1 production. Accordingly, the cash flows generated from our operating activities will provide an additional source of future funding. We believe that our available cash and cash flows from operations, together with the borrowings under the Facility, will be sufficient to meet our operating needs, service our existing debt, finance internal growth and fund capital expenditures through the next several years.

Significant Sources of Capital

In March 2011, the Company secured a $2.0 billion Facility from a number of financial institutions and extinguished the then existing commercial debt facilities. The Facility supports our oil and gas exploration, appraisal and development programs and corporate activities. The total loan commitments of the Facility may be increased up to a maximum of $3.0 billion if the lenders increase their commitments or if loan commitments from new financial institutions are added.

The 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). Kosmos pays commitment fees on the undrawn and unavailable portion of the total commitments. Commitment fees for the lenders 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. The Company recognizes 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 $1.0 million and $2.2 million of additional interest expense during the three and nine months ended September 30, 2011, respectively.

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

Kosmos has the right to cancel all the undrawn commitments under the Facility. The amount of funds available to be borrowed under the Facility, also known as the borrowing base amount, is determined each year on June 15 and December 15 as part of a forecast that is prepared by and agreed to by Kosmos 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. As of September 30, 2011, borrowings under the Facility totaled $1.0 billion. As of September 30, 2011, the undrawn availability under the Facility was an additional $407.3 million.

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

We were in compliance with the financial covenants contained in the Facility as of August 31, 2011, our most recent forecast date, which requires the maintenance of:

- the field life cover ratio, not less than 1.30x; and

- the loan life cover ratio, not less than 1.10x,

in each case, as calculated on the basis of all available information. 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 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. 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.

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 2011 exploration and appraisal drilling program in our offshore Ghana 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.

Oil production from the Jubilee Field commenced on November 28, 2010, and we have received revenues of $446.9 million in 2011.

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 working 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 or development efforts 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.

If MODEC, the contractor for the FPSO we are using to produce hydrocarbons from the Jubilee Field, is unable to secure long-term financing for the cost of the FPSO in order to repay amounts originally loaned by us and certain other Jubilee Unit partners under an Advance Payments Agreement (of which we are not a signatory, as TGL entered into such agreement as Unit Operator of the

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Jubilee Unit) and a construction loan from third parties for the financing of the construction of the FPSO, the Jubilee Unit partners may need to directly purchase the FPSO or find an alternative funding source or buyer. MODEC is required to repay amounts advanced on the earlier of November 28, 2011 or the date of the first drawdown under MODEC s long-term financing. Based on the terms of the Jubilee UUOA, TGL is required to reimburse us our share of the amounts MODEC reimburses TGL within 10 business days of repayment by MODEC. The Advance Payments Agreement grants to the Jubilee Unit partners the option to purchase the FPSO from MODEC on or before that same date. Should we elect to participate in any purchase of the vessel, the notes receivable under the Advance Payments Agreement of $109.4 million would be applied to the purchase price and our share of the remaining balance of cost to make such purchase is an amount up to approximately $120 million.

2011 Capital Program

We estimate we will incur approximately $500 million of capital expenditures for the year ending December 31, 2011. This capital expenditure budget consists of:

- $230 million for development in Ghana;
- $205 million for exploration and appraisal in Ghana;
- $20 million for exploration and appraisal in Cameroon; and
- $45 million for new ventures to expand our license portfolio (including geological and geophysical expenses).

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 natural gas 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 September 30, 2011 and November 1, 2011:

(In thousands)		**September 30, 2011**	**November 1, 2011**
Cash	$	656,442	656,102

Drawings under the commercial debt facility	1,000,000	1,000,000
Net debt	343,558	343,898
Total of unused borrowing base	407,300	407,300
Unused borrowing base plus cash	1,063,742	1,063,402

Cash Flows

	Nine Months Ended September 30, 2011	2010
	(In thousands)	
Net cash provided by (used in):		
Operating activities	$ 267,146	$ (133,180)
Investing activities	(194,027)	(451,164)
Financing activities	482,908	647,685

Operating activities. Net cash provided by operating activities for the nine months ended September 30, 2011 was $267.1 million, compared with net cash used in operating activities for the nine months ended September 30, 2010 of $133.2 million. The increase in cash provided by operating activities in the nine months ended September 30, 2011 compared with the same period in 2010 was primarily due to sales of oil from the Jubilee Field Phase 1 production and working capital changes.

Investing activities. Net cash used in investing activities for the nine months ended September 30, 2011 was $194.0 million, compared with net cash used in investing activities for the nine months ended September 30, 2010 of $451.2 million. The decrease in cash used in investing activities in the nine months ended September 30, 2011 compared with the same period in 2010 was primarily attributable to changes in restricted cash, notes receivable and expenditures for oil and gas assets primarily in Ghana for development

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activities. During the nine months ended September 30, 2010, we set aside $59.0 million of restricted cash to primarily support our drilling activities. During the nine months ended September 30, 2011, we released $112.0 million of associated restricted cash and set aside $26.4 million primarily related to requirements under the Facility.

Financing activities. Net cash provided by financing activities for the nine months ended September 30, 2011 was $482.9 million, compared with net cash provided by financing activities for the nine months ended September 30, 2010 of $647.7 million. The decrease in cash provided by financing activities in the nine months ended September 30, 2011 compared with the same period in 2010 was due to net proceeds from the initial public offering of $580.4 million offset by lower net borrowings of $710.0 million on the commercial debt facilities and a $35.2 million increase in cash used for deferred financing costs.

Contractual Obligations

The following table summarizes by period the payments due for our estimated contractual obligations as of September 30, 2011:

	Payments Due By Year(3)						
	Total	2011(4)	2012	2013	2014	2015	Thereafter
	(In thousands)						
Drilling rig contract(1)	$ 136,405	$	$ 136,405	$	$	$	$
Operating leases	22,023	227	234	2,821	2,921	3,022	12,798
Commercial debt facility(2)	1,000,000						1,000,000
Interest payments on commercial debt facility(5)	327,984	11,667	49,379	50,043	55,147	59,888	101,860

(1) Does not include any well commitments we may have under our oil and natural gas licenses.

(2) 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 September 30, 2011. 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.

(3) Does not include purchase commitments for jointly owned fields and facilities where we are not the operator.

(4) Represents payments for the period October 1, 2011 through December 31, 2011.

(5) Based on outstanding borrowings as noted in (2) above and six month LIBOR yield curves at the reporting date.

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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.

	October 1 Through December 31, 2011	Year Ending December 31, 2012	2013	2014	2015	Thereafter	Asset (Liability) Fair Value at September 30, 2011
	(In thousands, except percentages)						
Variable rate debt:							
Commercial debt facility maturities	$	$	$	$	$	$ 1,000,000	$ (1,000,000)
Weighted average interest rate	4.63%	4.94%	5.00%	5.51%	5.99%	7.50%	
Interest rate swaps:							
Notional debt amount(1)	$ 161,250	$ 138,073	$ 91,683	$ 47,033	$ 16,875	$ 6,250	$ (5,275)
Fixed rate payable	2.22%	2.22%	2.22%	2.22%	2.22%	2.22%	
Variable rate receivable(2)	0.40%	0.69%	0.77%	1.30%	2.03%	2.44%	
Notional debt amount(1)	$ 161,250	$ 138,073	$ 91,683	$ 47,033	$ 16,875	$ 6,250	$ (5,621)
Fixed rate payable	2.31%	2.31%	2.31%	2.31%	2.31%	2.31%	
Variable rate receivable(2)	0.40%	0.69%	0.77%	1.30%	2.03%	2.44%	
Notional debt amount(1)	$ 77,500	$ 63,625	$ 19,057	$ 1,868	$	$	$ (435)
Fixed rate payable	0.98%	0.98%	0.98%	0.98%			
Variable rate receivable(2)	0.40%	0.69%	0.77%	1.12%			
Notional debt amount(1)	$ 75,007	$ 50,942	$ 24,680	$ 38,434	$ 23,137	$	$ (770)
Fixed rate payable	1.34%	1.34%	1.34%	1.34%	1.34%		
Variable rate receivable(2)	0.40%	0.69%	0.77%	1.30%	1.89%		

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

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

Off-Balance Sheet Arrangements

As of September 30, 2011, we did not have any material off-balance sheet arrangements.

Critical Accounting Policies

We consider accounting policies related to our revenue recognition, exploration and development costs, receivables, income taxes, derivatives and hedging activities, estimates of proved oil and natural gas reserves, asset retirement obligations and impairment of long-lived assets as critical accounting policies. The policies include significant estimates made by management using information available at the time the estimates are made. However, these estimates could change materially if different information or assumptions were used. Please refer to Management s Discussion and Analysis of Financial Condition and Results of Operations in our final prospectus, which summarizes these accounting policies. Additionally, our accounting policy for income taxes is discussed below.

Income Taxes. We account for income taxes as required by ASC 740 Income Taxes. 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, 2010, we had a valuation allowance to reduce certain deferred tax assets to amounts that were 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.

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.

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The Company had net deferred tax assets in Ghana totaling approximately $30.3 million and $77.5 million at September 30, 2011 and December 31, 2010, respectively. Prior to the commencement of production from the Jubilee Field on November 28, 2010, the Company maintained a full valuation allowance against its net deferred tax asset. However, at December 31, 2010, the Company determined that it was more likely than not that the deferred tax asset for its Ghana operations would be recognized, resulting in the valuation allowance no longer being necessary. Therefore, we released the $20.6 million deferred tax asset valuation allowance and recognized $56.9 million of deferred tax assets generated during 2010. The factors that the Company considered are discussed below. Based on these factors, the Company concluded that many of the considerations that previously led to the need for a valuation allowance related to the Ghana deferred tax assets was not required as of December 31, 2010.

In determining that a valuation allowance was not needed for the Ghanaian deferred tax assets at December 31, 2010 we considered the requirements of ASC 740, including that all evidence, both positive and negative, should be considered to determine whether, based on all the weight of the available evidence, it is more-likely-than-not a deferred tax asset will or will not be realized. If it is more-likely-than-not that the deferred tax asset will be realized, a valuation allowance is not needed. In performing this assessment for the Ghanaian deferred tax assets, the Company determined that the factors that led to the creation of deferred tax assets while operating as a development stage entity changed significantly when the Company moved into the production phase. Accordingly, the Company believes that, considering the facts and circumstances, the negative evidence of the cumulative losses incurred during the development stage is overcome by the following positive evidence relating to the Company s ability to more-likely-than-not realize the deferred tax assets in Ghana:

- The commencement of oil production on November 28, 2010. Equipment and infrastructure was fully in place in the fourth quarter of 2010 immediately prior to production commencing, and the November 2010 successful commencement of production confirmed our expectations that these assets could be utilized to successfully produce from the field with an economical cost structure.

- The recognition of our first revenues from oil production in January 2011. The Company was a development stage entity as of December 31, 2010, but upon recognition of our first revenues in January 2011, is no longer categorized as such.

- The existence of significant proved reserves that have been independently verified.

- The Company produces a commodity (crude oil) with observable market demand capable of purchasing all barrels produced. Prices for oil can be estimated through forward pricing curves.

- The excess of appreciated asset value over the tax basis of our Ghanaian net assets of an amount sufficient to realize the deferred tax asset. Our estimates of the excess of the appreciated asset value were based upon the independently verified reserve report, third party offers for our Ghana assets, and other market indicators.

- There is an unlimited net operating loss carryforward period under Ghanaian tax law, which provides flexibility in utilization of the net operating loss.

ASC 740 provides a more-likely-than-not standard in evaluating whether a valuation allowance is necessary after weighing all of the available evidence. Using the more-likely-than-not standard and weighing all available positive and negative evidence, the Company concluded that the positive evidence outweighs the negative evidence of cumulative losses incurred during the development stage. Accordingly, we determined that it is more likely than not that the deferred tax asset for our Ghanaian operations would be recognized as of September 30, 2011 and December 31, 2010.

Effective January 1, 2009, we adopted the provisions of ASC 740 Income Taxes that clarifies the accounting for and disclosure of uncertainty in tax positions. Additionally, this standard provides guidance on the recognition, measurement, derecognition, classification and disclosure of tax positions and on the accounting for related interest and penalties. As a result of this adoption, we recognize accrued interest and penalties related to unrecognized tax benefits as a component of income tax expense.

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Cautionary Note Regarding Forward-looking Statements

This Quarterly Report on Form 10-Q contains estimates and forward-looking statements, principally in 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 final prospectus, may adversely affect our results as indicated in forward-looking statements. You should read this Quarterly Report on Form 10-Q, the final prospectus and the documents that we have filed with the Securities and Exchange Commission 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 Ghanaian, Cameroon or Moroccan governments or national oil companies, or any other federal, state or local governments, 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 and cost of developing appropriate infrastructure around and transportation to our discoveries and prospects;
- the availability and cost of drilling rigs, production equipment, supplies, personnel and oilfield services;
- other competitive pressures;
- potential liabilities inherent in oil and natural gas operations, including drilling risks and other operational and environmental hazards;
- current and future government regulation of the oil and gas industry;
- cost of compliance with laws and regulations;
- changes in environmental, health and safety or climate change laws, greenhouse gas regulation or the implementation, or interpretation, of those laws and regulations;
- environmental liabilities;
- geological, technical, drilling and processing problems;
- military operations, terrorist acts, wars or embargoes;
- the cost and availability of adequate insurance coverage;
- our vulnerability to severe weather events; and
- other risk factors discussed in the Risk Factors section of the final prospectus.

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The words believe, may, will, aim, estimate, continue, anticipate, intend, expect, plan and similar words are intended to identi 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 Quarterly Report on Form 10-Q 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.

Item 3. Quantitative and Qualitative 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 they are 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 speculation.

The following table reconciles the changes that occurred in fair values of our open derivative contracts during the nine months ending September 30, 2011:

	Derivative Contracts Assets (Liabilities)		
	Commodities	Interest Rates (In thousands)	Total
Fair value of contracts outstanding as of December 31, 2010	$ (28,319)	$ (5,638)	$ (33,957)
Changes in contract fair value	(5,250)	(9,933)	(15,183)
Contract maturities (settlements)	5,973	3,470	9,443
Fair value of contracts outstanding as of September 30, 2011	$ (27,596)	$ (12,101)	$ (39,697)

Commodity Derivative Instruments

In 2010, we entered into various oil derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil production. These contracts consisted of deferred premium puts and compound options (calls on puts).

We manage and control market and counterparty credit risk in accordance with policies and guidelines approved by the Kosmos Board of Directors. In accordance with these policies and guidelines, our executive management determines the appropriate timing and extent of derivative transactions. We attempt to minimize credit risk exposure to counterparties through formal credit policies, monitoring procedures and diversification. See Note 10 Derivative Financial Instruments in our consolidated financial statements for a description of the accounting procedures we follow relative to our derivative financial instruments.

Commodity Price Sensitivity

The following table provides information about our oil derivative financial instruments that were sensitive to changes in oil prices as of September 30, 2011:

	Bbl/day		Weighted Average Floor Price		Weighted Average Deferred Premium/bbl		Liability Fair Value at September 30, 2011
Oil derivatives:							
Deferred premium puts							
October 2011 December 2011	11,332	$	72.01	$	9.12		
January 2012 December 2012	4,625	$	62.74	$	7.04		
January 2013 December 2013	2,515	$	61.73	$	7.32		
Total fair value deferred premium puts(1)						$	22,432
Compound options (calls on puts)(2)							
July 2012 December 2012	5,399	$	66.48	$	6.73		
January 2013 June 2013	3,855	$	66.48	$	7.10		
Total fair value compound options(1)						$	5,164

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(1) Fair values are based on the average forward Dated Brent oil prices on September 30, 2011 which by year are: 2011 - $100.15; 2012 - $97.42 and 2013 - $95.07. These fair values are subject to changes in the underlying commodity price. The average forward Dated Brent oil prices based on November 1, 2011 market quotes by year are: 2011- $108.08; 2012 - $104.48 and 2013 - $100.04.

(2) The calls expire June 29, 2012 and have a weighted average premium of $4.82/bbl.

Interest Rate Sensitivity

At September 30, 2011, we had indebtedness outstanding under our Facility of $1.0 billion, of which $525.0 million bore interest at floating rates. The weighted average annual interest rate incurred on this indebtedness for the nine months ended September 30, 2011, was approximately 5.1%. 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 our Facility.

As of September 30, 2011, the fair market value of our interest rate swaps was a net liability of approximately $12.1 million. If LIBOR increased 10%, we estimate the liability would decrease to approximately $11.3 million, and if LIBOR decreased 10%, we estimate the liability would increase to approximately $12.9 million.

Item 4. 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. Based on that evaluation, the Company s Chief Executive Officer and Chief Financial Officer concluded that the Company s disclosure controls and procedures were effective as of September 30, 2011, to provide reasonable assurance that the information required to be disclosed in the reports it files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities Exchange Commission s rules and forms, and that such information is accumulated and communicated to the Company s management, including our Chief Executive Officer and Chief Financial Officer, as appropriate 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 during the three and nine months ended September 30, 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

We are not currently party to any litigation or legal proceedings with respect to the Company s operations that management believes, based on advice of legal counsel, will either individually or in the aggregate have a materially adverse impact on the Company s financial condition, results of operations or cash flows. However, from time to time we may be subject to various lawsuits, claims and proceedings that arise in the normal course of business, including employment, commercial, environmental, safety and health matters. It is not presently possible to determine whether any such matters will have a material adverse effect on our consolidated financial position, results of operations, or liquidity.

Item 1A. Risk Factors

There have been no material changes from the risk factors previously disclosed in the final prospectus other than as follows:

We will not have a license for the Cap Boujdour Offshore Block offshore Morocco and we may not be able to commence our exploration operations on this block until the Cap Boujdour Petroleum Agreement governing our interests in such block is both approved by a ministerial order and such approval is published in the official gazette, in accordance with Moroccan law. The ministerial order approving the Petroleum Agreement has been signed; however, publication in the official gazette has not yet taken place.

In July 2011, we entered into the Cap Boujdour Petroleum Agreement with ONHYM. Our Cap Boujdour Offshore Block award will not be final and we will not have a license for the Cap Boujdour Offshore Block unless and until this Petroleum Agreement is approved by a joint ministerial order by the Moroccan Minister for Energy and the Minister of Finance, and such approval is published in the official gazette in accordance with Moroccan law. The joint ministerial order approving the Petroleum Agreement has been signed; however, publication in the official gazette has not yet taken place. There is a risk that the Cap Boujdour Petroleum Agreement will not be published in the official gazette and that we may be unable to enforce any contractual rights we have in the Cap

Boujdour Offshore Block and we may not be able to commence our exploration operations on the Cap Boujdour Offshore Block. Further, if the Cap Boujdour Offshore Petroleum Agreement is published later than we expect, our planned activities offshore Morocco could be delayed.

We will not have a license for the Essaouira Block offshore Morocco and we may not be able to commence our exploration operations on this block until the Essaouira Petroleum Agreement governing our interests in such block is approved by a ministerial order and such approval is published in the official gazette in accordance with Moroccan law.

In September 2011, we entered into the Essaouira Petroleum Agreement with ONHYM and Canamens. Our Essaouira Offshore Block award will not be final and we will not have a license for the Essaouira Offshore Block unless and until this Petroleum Agreement is approved by a joint ministerial order by the Moroccan Minister for Energy and the Minister of Finance, and such approval is published in the official gazette in accordance with Moroccan law. There is a risk that the Essaouira Petroleum Agreement will not receive a joint ministerial order or that the order will not be published in the official gazette and that we may be unable to enforce any contractual rights we have in the Essaouira Offshore Block and we may not be able to commence our exploration operations on the Essaouira Offshore Block. Further, if the Essaouira Offshore Petroleum Agreement receives ministerial approval later than we expect or publishing in the official gazette is delayed, our planned activities offshore Morocco could be delayed.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Our initial public offering 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 37,950,000 of our common shares at a public offering price of $18.00 per share, which would have yielded proceeds of $683.1 million. On May 16, 2011, the Company registered and publicly sold 33,000,000 common shares. The underwriters had an over-allotment option to purchase 4,950,000 additional common shares within 30 days of May 10, 2011. On June 14, 2011, the Company closed the sale of an additional 1,518,242 common shares pursuant to the over-allotment option exercised by the underwriters of the initial public offering. This partial exercise of the over-allotment option brings the total number of common shares sold in the offering to 34,518,242 at a public offering price of $18.00 per share, for gross proceeds of approximately $621.3 million. Our net proceeds from the sale of 34,518,242 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 initial public offering from that described in our final prospectus dated May 10, 2011 and filed with the Securities and Exchange Commission pursuant to Rule 424(b).

On July 11, 2011 we used $130.0 million of net proceeds as part of the $300.0 million prepayment on the Facility.

On June 10, 2011 we used $15.0 million of net proceeds to pay GNPC as part of the settlement agreement with GNPC and the Government of Ghana.

Pending use of the remaining proceeds, we have invested these net proceeds in institutionally-managed accounts that consists of highly rated investment funds.

Item 3. Defaults Upon Senior Securities

None.

Item 4. (Removed and Reserved)

Item 5. Other Information.

There have been no material changes required to be reported under this Item that have not previously been disclosed in the final prospectus.

Item 6. Exhibits

The information required by this Item 6 is set forth in the Index to Exhibits accompanying this quarterly report on Form 10-Q.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereto duly authorized.

Kosmos Energy Ltd.
(Registrant)

Date November 10, 2011

/s/ W. GREG DUNLEVY
W. Greg Dunlevy
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

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INDEX TO EXHIBITS

Exhibit Number	Description of Document
3.1	Certificate of Incorporation of the Company (filed as Exhibit 3.1 to the Company s Amendment No. 2 to registration statement on Form S-1 (File No. 333-171700) filed with the Securities and Exchange Commission on March 23, 2011 and incorporated herein by reference)
3.2	Memorandum of Association of Kosmos Energy Ltd. (filed as Exhibit 3.2 to the Company s Amendment No. 2 to registration statement on Form S-1 (File No. 333-171700) filed with the Securities and Exchange Commission on March 23, 2011 and incorporated herein by reference)
3.3	Form of Bye-laws of Kosmos Energy Ltd. (filed as Exhibit 3.3 to the Company s Amendment No. 3 to registration statement on Form S-1 (File No. 333-171700) filed with the Securities and Exchange Commission on March 30, 2011 and incorporated herein by reference)
4.1	Specimen Share Certificate (filed as Exhibit 4.1 to the Company s Amendment No. 5 to registration statement on Form S-1 (File No. 333-171700) filed with the Securities and Exchange Commission on April 25, 2011 and incorporated herein by reference)
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.
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.