UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2017

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 No

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

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

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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

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 August 1, 2017
Common Shares, $0.01 par value	389,286,890

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Unless otherwise stated in this report, references to "Kosmos," "we," "us" or "the company" refer to Kosmos Energy Ltd. and its subsidiaries. We have provided definitions for some of the industry terms used in this report in the "Glossary and Selected Abbreviations" beginning on page 3.

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KOSMOS ENERGY LTD.

GLOSSARY AND SELECTED ABBREVIATIONS

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

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

"Developed acreage"	The number of acres that are allocated or assignable to productive wells or wells capable of production.
"Development"	The phase in which an oil or natural gas field is brought into production by drilling development wells and installing appropriate production systems.

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“Dry hole”	A well that has not encountered a hydrocarbon bearing reservoir expected to produce in commercial quantities.
“EBITDAX”	Net income (loss) plus (i) exploration expense, (ii) depletion, depreciation and amortization expense, (iii) equity-based compensation expense, (iv) unrealized (gain) loss on commodity derivatives (realized losses are deducted and realized gains are added back), (v) (gain) loss on sale of oil and gas properties, (vi) interest (income) expense, (vii) income taxes, (viii) loss on extinguishment of debt, (ix) doubtful accounts expense and (x) similar other material items which management believes affect the comparability of operating results.
“E&P”	Exploration and production.
“FASB”	Financial Accounting Standards Board.
“Farm-in”	An agreement whereby a party acquires a portion of the participating interest in a block from the owner of such interest, usually in return for cash and for taking on a portion of the drilling costs of one or more specific wells or other performance by the assignee as a condition of the assignment.
“Farm-out”	An agreement whereby the owner of the participating interest agrees to assign a portion of its participating interest in a block to another party for cash and/or for the assignee taking on a portion of the drilling costs of one or more specific wells and/or other work as a condition of the assignment.
“Field life cover ratio”	The “field life cover ratio” is broadly defined, for each applicable forecast period, as the ratio of (x) the forecasted net present value of net cash flow through depletion plus the net present value of the forecast of certain capital expenditures incurred in relation to the Ghana assets, to (y) the aggregate loan amounts outstanding under the Facility less the Resource Bridge, as applicable.
“FPSO”	Floating production, storage and offloading vessel.
“Interest cover ratio”	The “interest cover ratio” is broadly defined, for each applicable calculation date, as the ratio of (x) the aggregate EBITDAX (see above) of the Company for the previous twelve months, to (y) interest expense less interest income for the Company for the previous twelve months.
“Loan life cover ratio”	The “loan life cover ratio” is broadly defined, for each applicable forecast period, as the ratio of (x) net present value of forecasted net cash flow through the final maturity date of the Facility plus the net present value of forecasted capital expenditures incurred in relation to the Jubilee Field and certain other fields in Ghana, to (y) the aggregate loan amounts outstanding under the Facility less the Resource Bridge, as applicable.
“Make-whole redemption price”	The “make-whole redemption price” is equal to the outstanding principal amount of such notes plus the greater of 1) 1% of the then outstanding principal amount of such notes and 2) the present value of the notes at 103.9% and required interest payments thereon through August 1, 2017 at such redemption date.

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“MBbl”	Thousand barrels of oil.
“Mcf”	Thousand cubic feet of natural gas.
“Mcfpd”	Thousand cubic feet per day of natural gas.
“MMBbl”	Million barrels of oil.
“MMBoe”	Million barrels of oil equivalent.
“MMcf”	Million cubic feet of natural gas.
“Natural gas liquid” or “NGL”	Components of natural gas that are separated from the gas state in the form of liquids. These include propane, butane, and ethane, among others.
“Petroleum contract”	A contract in which the owner of hydrocarbons gives an E&P company temporary and limited rights, including an exclusive option to explore for, develop, and produce hydrocarbons from the lease area.
“Petroleum system”	A petroleum system consists of organic material that has been buried at a sufficient depth to allow adequate temperature and pressure to expel hydrocarbons and cause the movement of oil and natural gas from the area in which it was formed to a reservoir rock where it can accumulate.
“Plan of development” or “PoD”	A written document outlining the steps to be undertaken to develop a field.
“Productive well”	An exploratory or development well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.
“Prospect(s)”	A potential trap that may contain hydrocarbons and is supported by the necessary amount and quality of geologic and geophysical data to indicate a probability of oil and/or natural gas accumulation ready to be drilled. The five required elements (generation, migration, reservoir, seal and trap) must be present for a prospect to work and if any of these fail neither oil nor natural gas may be present, at least not in commercial volumes.
“Proved reserves”	Estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be economically recoverable in future years from known reservoirs under existing economic and operating conditions, as well as additional reserves expected to be obtained through confirmed improved recovery techniques, as defined in SEC Regulation S-X 4-10(a)(2).
“Proved developed reserves”	Those proved reserves that can be expected to be recovered through existing wells and facilities and by existing operating methods.
“Proved undeveloped	Those proved reserves that are expected to be recovered from future wells and facilities, including future improved recovery projects which are anticipated with a high degree of certainty in

reserves”	reservoirs which have previously shown favorable response to improved recovery projects.

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

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KOSMOS ENERGY LTD.

CONSOLIDATED BALANCE SHEETS

(In thousands, except share data)

	June 30, 2017 (Unaudited)	December 31, 2016
Assets		
Current assets:		
Cash and cash equivalents	$ 162,474	$ 194,057
Restricted cash	40,776	24,506
Receivables:		
Joint interest billings, net	56,606	63,249
Oil sales	43,152	54,195
Related party	26,208	—
Other	59,856	25,893
Inventories	79,871	74,380
Prepaid expenses and other	7,491	7,209
Derivatives	37,041	31,698
Total current assets	513,475	475,187
Property and equipment:		
Oil and gas properties, net	2,290,338	2,700,889
Other property, net	7,087	8,003
Property and equipment, net	2,297,425	2,708,892
Other assets:		
Equity method investment	127,467	—
Restricted cash	28,295	54,632
Long-term receivables - joint interest billings	45,671	45,663
Deferred financing costs, net of accumulated amortization of $12,582 and $11,213 at June 30, 2017 and December 31, 2016, respectively	3,879	5,248
Long-term deferred tax assets	32,427	37,827
Derivatives	10,427	3,808
Other	17,293	10,208
Total assets	$ 3,076,359	$ 3,341,465
Liabilities and shareholders’ equity		
Current liabilities:		

Accounts payable	$ 89,147	$ 220,627
Accrued liabilities	190,261	129,706
Derivatives	2,932	19,692
Total current liabilities	282,340	370,025
Long-term liabilities:		
Long-term debt, net	1,127,503	1,321,874
Derivatives	3,318	14,123
Asset retirement obligations	66,935	63,574
Deferred tax liabilities	517,970	482,221
Other long-term liabilities	15,440	8,449
Total long-term liabilities	1,731,166	1,890,241
Shareholders' equity:		
Preference shares, $0.01 par value; 200,000,000 authorized shares; zero issued at June 30, 2017 and December 31, 2016	—	—
Common shares, $0.01 par value; 2,000,000,000 authorized shares; 398,348,929 and 395,859,061 issued at June 30, 2017 and December 31, 2016, respectively	3,983	3,959
Additional paid-in capital	1,994,785	1,975,247
Accumulated deficit	(887,718)	(850,410)
Treasury stock, at cost, 9,188,819 and 9,101,395 shares at June 30, 2017 and December 31, 2016, respectively	(48,197)	(47,597)
Total shareholders' equity	1,062,853	1,081,199
Total liabilities and shareholders' equity	$ 3,076,359	$ 3,341,465

See accompanying notes.

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KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Revenues and other income:				
Oil and gas revenue	$ 136,363	$ 45,506	$ 239,795	$ 107,631
Other income, net	10,161	170	58,695	178
Total revenues and other income	146,524	45,676	298,490	107,809
Costs and expenses:				
Oil and gas production	21,604	32,681	41,490	62,073
Facilities insurance modifications, net	(2)	—	2,572	—
Exploration expenses	19,982	36,402	125,696	60,260
General and administrative	14,739	19,838	30,526	37,758
Depletion and depreciation	72,441	16,927	107,419	48,193
Interest and other financing costs, net	19,465	8,878	36,251	19,202
Derivatives, net	(25,411)	54,988	(63,268)	50,643
Other expenses, net	8,434	(170)	9,196	14,563
Total costs and expenses	131,252	169,544	289,882	292,692
Income (loss) before income taxes	15,272	(123,868)	8,608	(184,883)
Income tax expense (benefit)	23,739	(15,544)	45,916	(17,566)
Net loss	$ (8,467)	$ (108,324)	$ (37,308)	$ (167,317)
Net loss per share:				
Basic	$ (0.02)	$ (0.28)	$ (0.10)	$ (0.43)
Diluted	$ (0.02)	$ (0.28)	$ (0.10)	$ (0.43)
Weighted average number of shares used to compute net loss per share:				

Basic	387,952	384,918	387,634	384,676
Diluted	387,952	384,918	387,634	384,676

See accompanying notes.

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KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(In thousands)

(Unaudited)

	Common Shares		Additional Paid-in	Accumulated	Treasury	
	Shares	Amount	Capital	Deficit	Stock	Total
Balance as of December 31, 2016	395,859	$ 3,959	$ 1,975,247	$ (850,410)	$ (47,597)	$ 1,081,199
Equity-based compensation	—	—	20,907	—	—	20,907
Restricted stock awards and units	2,490	24	(24)	—	—	—
Purchase of treasury stock	—	—	(1,345)	—	(600)	(1,945)
Net loss	—	—	—	(37,308)	—	(37,308)
Balance as of June 30, 2017	398,349	$ 3,983	$ 1,994,785	$ (887,718)	$ (48,197)	$ 1,062,853

See accompanying notes.

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KOSMOS ENERGY LTD.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

(Unaudited)

	Six Months Ended June 30, 2017	2016
Operating activities		
Net loss	$ (37,308)	$ (167,317)
Adjustments to reconcile net loss to net cash used in operating activities:		
Depletion, depreciation and amortization	112,521	53,295
Deferred income taxes	41,017	(19,929)
Unsuccessful well costs	3,605	2,300
Change in fair value of derivatives	(58,944)	55,175
Cash settlements on derivatives, net (including $24.3 million and $101.8 million on commodity hedges during 2017 and 2016)	19,417	99,815
Equity-based compensation	20,329	21,162
Loss on equity method investment	6,426	—
Other	2,514	15,069
Changes in assets and liabilities:		
Increase in receivables	(28,251)	(11,225)
Increase in inventories	(6,038)	(1,082)
(Increase) decrease in prepaid expenses and other	(17,459)	18,985
Decrease in accounts payable	(131,480)	(80,359)
Increase (decrease) in accrued liabilities	56,137	(9,967)
Net cash used in operating activities	(17,514)	(24,078)
Investing activities		
Oil and gas assets	(42,805)	(417,704)
Other property	(1,454)	(601)
Proceeds on sale of assets	222,068	196
Net cash provided by (used in) investing activities	177,809	(418,109)
Financing activities		
Borrowings under long-term debt	—	325,000
Payments on long-term debt	(200,000)	—
Purchase of treasury stock	(1,945)	(1,798)

Net cash provided by (used in) financing activities	(201,945)	323,202
Net decrease in cash, cash equivalents and restricted cash	(41,650)	(118,985)
Cash, cash equivalents and restricted cash at beginning of period	273,195	310,862
Cash, cash equivalents and restricted cash at end of period	$ 231,545	$ 191,877
Supplemental cash flow information		
Cash paid for:		
Interest	$ 24,944	$ 8,200
Income taxes	$ 27,199	$ 6,978
Non-cash activity:		
Conversion of joint interest billings receivable to long-term note receivable	$ —	$ 5,033
Contribution to equity method investment	$ 133,893	$ —

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 in March 2004. As a holding company, Kosmos Energy Ltd.'s management operations are conducted through a wholly owned subsidiary, Kosmos Energy, LLC. The terms "Kosmos," the "Company," "we," "us," "our," "ours," ar similar terms refer to Kosmos Energy Ltd. and its wholly owned subsidiaries, unless the context indicates otherwise.

Kosmos is a leading independent oil and gas exploration and production company focused on frontier and emerging areas along the Atlantic Margins. Our assets include existing production and development projects offshore Ghana, large discoveries and significant further hydrocarbon exploration potential offshore Mauritania and Senegal, as well as exploration licenses with significant hydrocarbon potential offshore Sao Tome and Principe, Suriname, Morocco and Western Sahara. Kosmos is listed on the New York Stock Exchange and is traded under the ticker symbol KOS.

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

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 June 30, 2017, the changes in the consolidated statements of shareholders' equity for the six months ended June 30, 2017, the consolidated results of operations for the three and six months ended June 30, 2017 and 2016, and the consolidated cash flows for the six months ended June 30, 2017 and 2016. 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. The consolidated financial statements were prepared in accordance with the requirements of the Securities and Exchange Commission ("SEC") for interim reporting. As permitted under those rules, certain notes or other financial information that are normally required by Generally Accepted Accounting Principles in the United States of America ("GAAP") have been condensed or omitted from these interim consolidated financial statements. 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, 2016, included in our annual report on Form 10-K.

Investment in Corporate Joint Venture

Kosmos holds a 50.01% interest in Kosmos BP Senegal Limited ("KBSL"), which we exercise significant influence over. Our investment in KBSL is accounted for under the equity method of accounting. In applying the equity method of accounting, our investment in KBSL was initially recorded at carryover basis and subsequently adjusted for the Company's proportionate share of earnings, losses and distributions. During the three and six month periods ended June 30, 2017 we recognized $6.4 million related to our share of losses in KBSL. As of June 30, 2017, our investment in KBSL was $127.5 million and is reported as an equity method investment in our consolidated balance sheets. We had related party receivables of $26.2 million as of June 30, 2017, which relate to amounts due from KBSL for costs incurred by Kosmos on behalf of KBSL.

Reclassifications

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

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Cash, Cash Equivalents and Restricted Cash

	June 30, 2017	December 31, 2016
	(In thousands)	
Cash and cash equivalents	$ 162,474	$ 194,057
Restricted cash - current	40,776	24,506
Restricted cash - long-term	28,295	54,632
Total cash, cash equivalents and restricted cash shown in the consolidated statements of cash flows	$ 231,545	$ 273,195

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

In accordance with our commercial debt facility (the “Facility”), we are required to maintain a restricted cash balance that is sufficient to meet the payment of interest and fees for the next six-month period on the 7.875% Senior Secured Notes due 2021 (“Senior Notes”) plus the Corporate Revolver or the Facility, whichever is greater. As of June 30, 2017 and December 31, 2016, we had $24.6 million and $24.5 million, respectively, in current restricted cash to meet this requirement.

In addition, in accordance with certain of our petroleum contracts, we have posted letters of credit related to performance guarantees for our minimum work obligations. These letters of credit are cash collateralized in accounts held by us and as such are classified as restricted cash. Upon completion of the minimum work obligations and/or entering into the next phase of the petroleum contract, the requirement to post the existing letters of credit will be satisfied and the cash collateral will be released. However, additional letters of credit may be required should we choose to move into the next phase of certain of our petroleum contracts. As of June 30, 2017 and December 31, 2016, we had $16.2 million and zero, respectively, of current restricted cash and $28.3 million and $54.6 million, respectively, of long-term restricted cash used to collateralize performance guarantees related to our petroleum contracts.

Inventories

Inventories consisted of $74.0 million and $68.1 million of materials and supplies and $5.9 million and $6.3 million of hydrocarbons as of June 30, 2017 and December 31, 2016, 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 net realizable value. We recorded write downs of $0.5 million and $15.2 million during the six months ended June 30, 2017 and 2016, respectively, for materials and supplies inventories as other expenses, net in the consolidated statements of operations and other in the consolidated statements of cash flows.

Hydrocarbon inventory is carried at the lower of cost, using the weighted average cost method, or net realizable value. Hydrocarbon inventory costs include expenditures and other charges incurred in bringing the inventory to its existing condition. Selling expenses and general and administrative expenses are reported as period costs and excluded from inventory costs.

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3. Acquisitions and Divestitures

In December 2016, we announced transactions with affiliates of BP p.l.c. (‘‘BP’’) in Mauritania and Senegal following a competitive farm-out process for our interests in our blocks offshore Mauritania and Senegal. The Mauritania and Senegal transactions closed in January 2017 and February 2017, respectively. In Mauritania, BP acquired a 62% participating interest in our four Mauritania licenses (C6, C8, C12 and C13). In Senegal, BP acquired a 49.99% interest in KBSL, our majority owned affiliate company which holds a 60% participating interest in the Cayar Offshore Profond and the Saint Louis Offshore Profond blocks offshore Senegal. Previously we indicated that KBSL would hold a 65% participating interest upon the completion of our exercise in December 2016 of an option to increase our equity in each contract area by 5% in exchange for carrying Timis Corporation Limited’s (“Timis”) paying interest share of a third well in either contract area, subject to a maximum gross well cost of $120.0 million. However, we have agreed to withdraw the exercise of this call option upon completion of an agreement between BP and Timis by which BP acquired Timis’ entire 30% participating interest in the Cayar Offshore Profond and the Saint Louis Offshore Profond blocks. The transaction between BP and Timis has now been completed and KBSL’s participating interest in these blocks remains at 60%. In consideration for these transactions, Kosmos received $162 million in cash up front during the first quarter of 2017 and will receive a $221 million exploration and appraisal carry, up to $533 million in a development carry and variable consideration up to $2 per barrel for up to 1 billion barrels of liquids, structured as a production royalty, subject to future liquids discoveries and prevailing oil prices. The effective date of these transactions was July 1, 2016, with BP paying interim costs from the effective date to the closing dates. We reduced our unproved property balance by $221.9 million for the consideration received as a result of these transactions including the upfront cash and interim costs from the transaction date to the effective date.

In November 2015, we entered into a line of credit agreement with Timis, whereby Timis had the right to draw up to $30.0 million on the line of credit to offset its joint interest billings arising from costs under the Senegal petroleum agreements. As of June 30, 2017, there was $16 million outstanding under the agreement, which is included in other receivables. We agreed with Timis to terminate this line of credit agreement when Timis’ transaction with BP for the transfer of Timis’ 30% participating interest in the Cayar Offshore Profond and the Saint Louis Offshore Profond blocks offshore Senegal was completed. As a result of termination of this credit agreement, Kosmos expects to receive this $16 million in early August.

In June 2017, we entered into a farm-in agreement with Tullow Mauritania Limited, a subsidiary of Tullow Oil plc (“Tullow”), to acquire a 15% non-operated participating interest in Block C18 offshore Mauritania. Based on the terms of the agreement, we will reimburse a portion of past and interim period costs and partially carry Tullow’s share of a planned 3D seismic program (up to $2.1 million net to Kosmos). We will also pay Tullow $2.5 million by the end of the initial phase of the exploration period for additional carry of seismic and other joint account costs. Certain governmental approvals are still required to be completed before this agreement is effective.

4. Joint Interest Billings

The Company's joint interest billings consist of receivables from partners with interests in common oil and gas properties operated by the Company. Joint interest billings are classified on the face of the consolidated balance sheets as current and long-term receivables based on when collection is expected to occur.

In 2014, the Ghana National Petroleum Corporation ("GNPC") notified us and our block partners of its request for the contractor group to pay GNPC's 5% share of the Tweneboa, Enyenra and Ntomme ("TEN") development costs. The block partners will be reimbursed for such costs plus interest out of a portion of GNPC's TEN production revenues under the terms of the Deepwater Tano ("DT") petroleum contract. As of June 30, 2017 and December 31, 2016, the joint interest billing receivables due from GNPC for the TEN development costs were $1.6 million and zero, respectively, which are classified as current and $45.7 million and $44.0 million, respectively, which are classified as long-term on the consolidated balance sheets.

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5. Property and Equipment

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

	June 30, 2017	December 31, 2016
	(In thousands)	
Oil and gas properties:		
Proved properties	$ 1,373,694	$ 1,385,331
Unproved properties	624,615	919,056
Support equipment and facilities	1,384,349	1,386,448
Total oil and gas properties	3,382,658	3,690,835
Accumulated depletion	(1,092,320)	(989,946)
Oil and gas properties, net	2,290,338	2,700,889
Other property	37,952	37,186
Accumulated depreciation	(30,865)	(29,183)
Other property, net	7,087	8,003
Property and equipment, net	$ 2,297,425	$ 2,708,892

We recorded depletion expense of $69.9 million and $14.9 million for the three months ended June 30, 2017 and 2016, respectively, and $102.4 and $44.1 million for the six months ended June 30, 2017 and 2016, respectively.

6. Suspended Well Costs

The following table reflects the Company’s capitalized exploratory well costs on completed wells as of and during the six months ended June 30, 2017. The table excludes $3.6 million in costs that were capitalized and subsequently expensed during the same period.

	June 30, 2017
	(In thousands)
Beginning balance	$ 734,463
Additions to capitalized exploratory well costs pending the determination of proved reserves	30,663
Reclassification due to determination of proved reserves	—

Divestitures(1)	(206,400)
Contribution of oil and gas property to equity method investment	(131,764)
Capitalized exploratory well costs charged to expense	—
Ending balance	$ 426,962

(1) Represents the reduction in basis of suspended well costs associated with the Mauritania and Senegal transactions with BP.

The following table provides an 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:

	June 30, 2017	December 31, 2016
	(In thousands, except well counts)	
Exploratory well costs capitalized for a period of one year or less	$ 29,663	$ 279,809
Exploratory well costs capitalized for a period of one to two years	183,623	244,804
Exploratory well costs capitalized for a period of three to eight years	213,676	209,850
Ending balance	$ 426,962	$ 734,463
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	6	5

As of June 30, 2017, the projects with exploratory well costs capitalized for more than one year since the completion of drilling are related to the Mahogany, Teak (formerly Teak-1 and Teak-2) and Akasa discoveries in the West

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Cape Three Points ("WCTP") Block and the Wawa discovery in the DT Block, which are all located offshore Ghana, the Greater Tortue discovery which crosses the Mauritania and Senegal maritime border, the BirAllah discovery (formerly known as the Marsouin discovery) in Block C8 offshore Mauritania and the Teranga discovery in the Cayar Offshore Profond block offshore Senegal.

Mahogany and Teak Discoveries — In November 2015, we signed the Jubilee Field Unit Expansion Agreement with our partners to allow for the development of the Mahogany and Teak discoveries through the Jubilee FPSO and infrastructure. The expansion of the Jubilee Unit becomes effective upon approval by Ghana's Ministry of Petroleum of the Greater Jubilee Full Field Development Plan ("GJFFDP"). The initial plan was submitted to the government of Ghana in December 2015. The GJFFDP encompasses future development of the Jubilee Field, in addition to future development of the Mahogany and Teak discoveries, which were declared commercial during 2015. The partners remain on track to resubmit the GJFFDP, which was optimized given the current oil price environment to reduce overall capital costs, to the government of Ghana with approval expected later in the year. Upon approval of the GJFFDP by the Ministry of Energy, the Jubilee Unit will be expanded to include the Mahogany and Teak discoveries and revenues and expenses associated with these discoveries will be at the Jubilee Unit interests. The WCTP Block partners have agreed they will take the steps necessary to transfer operatorship of the remaining portions of the WCTP Block to Tullow after approval of the GJFFDP by Ghana's Ministry of Energy.

Akasa Discovery — We are currently in discussions with the government of Ghana regarding additional technical studies and evaluation that we want to conduct before we are able to make a determination regarding commerciality of the discovery. If we determine the discovery to be commercial, a declaration of commerciality would be provided and a PoD would be prepared and submitted to Ghana's Ministry of Energy, as required under the WCTP petroleum contract. The WCTP Block partners have agreed they will take the steps necessary to transfer operatorship of the remaining portions of the WCTP Block, including the Akasa Discovery, to Tullow after approval of the GJFFDP by Ghana's Ministry of Energy.

Wawa Discovery — In February 2016, we requested the Ghana Ministry of Energy to approve the enlargement of the areal extent of the TEN fields and production area to capture the resource accumulation located in the Wawa Discovery Area for a potential future integrated development with the TEN fields. In April 2016, the Ghana Ministry of Energy approved our request to enlarge the TEN development and production area subject to continued subsurface and development concept evaluation, along with the requirement to integrate the Wawa Discovery into the TEN PoD. We are currently in discussions with the Ministry of Energy with respect to conducting further subsurface and development concept evaluation.

Greater Tortue Discovery — In May 2015, we completed the Tortue-1 exploration well in Block C8 offshore Mauritania which encountered hydrocarbon pay. Two additional wells have been drilled in the Greater Tortue Discovery area, Ahmeyim-2 in Mauritania and Guembeul-1 in Senegal. We are currently performing a drill stem test on the Tortue 1 well to confirm the production capabilities of the Greater Tortue Discovery to further refine the Front End Engineering Design (FEED) in the second half of 2017. Following additional evaluation, a decision regarding commerciality will be made.

BirAllah Discovery — In November 2015, we completed the Marsouin-1 exploration well (renamed BirAllah) in the northern part of Block C8 offshore Mauritania which encountered hydrocarbon pay. Following additional evaluation, a decision regarding commerciality will be made.

Teranga Discovery — In May 2016, we completed the Teranga-1 exploration well in the Cayar Offshore Profond block offshore Senegal which encountered hydrocarbon pay. Following additional evaluation, a decision regarding commerciality will be made.

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7. Debt

	June 30, 2017	December 31, 2016
	(In thousands)	
Outstanding debt principal balances:		
Facility	$ 650,000	$ 850,000
Senior Notes	525,000	525,000
Total	1,175,000	1,375,000
Unamortized deferred financing costs and discounts(1)	(47,497)	(53,126)
Long-term debt, net	$ 1,127,503	$ 1,321,874

(1) Includes $26.8 million and $30.3 million of unamortized deferred financing costs related to the Facility and $20.7 million and $22.8 million of unamortized deferred financing costs and discounts related to the Senior Notes as of June 30, 2017 and December 31, 2016, respectively.

Facility

In March 2014, the Company amended and restated the Facility with a total commitment of $1.5 billion from a number of financial institutions. The Facility supports our oil and gas exploration, appraisal and development programs and corporate activities.

In March 2017, following the lender's semi-annual redetermination, the borrowing base under our Facility was $1.3 billion (effective April 1, 2017). The borrowing base calculation includes value related to the Jubilee and TEN fields. As of June 30, 2017, borrowings under the Facility totaled $650.0 million and the undrawn availability under the Facility was $650.8 million.

The Facility provides a revolving-credit and letter of credit facility. The availability period for the revolving-credit facility, as amended in March 2014, expires on March 31, 2018, however, the Facility has a revolving-credit sublimit, which will be the lesser of $500.0 million and the total available facility at that time, that will be available for drawing until the date falling one month prior to the final maturity date. The letter of credit facility expires on the final maturity date. The available facility amount is subject to borrowing base constraints and, beginning on March 31, 2018, outstanding borrowings will be constrained by an amortization schedule. The Facility has a final maturity date of March 31, 2021. As of June 30, 2017, we had no letters of credit issued under the Facility.

We were in compliance with the financial covenants contained in the Facility as of March 31, 2017 (the most recent assessment date). The Facility contains customary cross default provisions.

Corporate Revolver

In June 2015, we amended and restated the Corporate Revolver from a number of financial institutions, increasing the borrowing capacity to $400.0 million, extending the maturity date to November 2018 and lowering the commitment fees on the undrawn portion of the total commitments to 30% per annum of the respective margin. The Corporate Revolver is available for all subsidiaries for general corporate purposes and for oil and gas exploration, appraisal and development programs. As of June 30, 2017, we have $3.9 million of net deferred financing costs related to the Corporate Revolver, which will be amortized over the remaining term. These deferred financing costs are included in the Other assets section of the consolidated balance sheets.

As of June 30, 2017, there were no borrowings outstanding under the Corporate Revolver and the undrawn availability under the Corporate Revolver was $400.0 million. We were in compliance with the financial covenants contained in the Corporate Revolver as of March 31, 2017 (the most recent assessment date). The Corporate Revolver contains customary cross default provisions.

Revolving Letter of Credit Facility

In July 2016, we amended and restated the revolving letter of credit facility agreement (“LC Facility”), extending the maturity date to July 2019. During the first quarter of 2017, the LC Facility size was increased to $115.0 million. In

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April 2017, we reduced the size of our LC Facility to $70 million. As of June 30, 2017, there were seven outstanding letters of credit totaling $57.7 million under the LC Facility. The LC Facility contains customary cross default provisions.

7.875% Senior Secured Notes due 2021

During August 2014, the Company issued $300.0 million of Senior Notes and received net proceeds of approximately $292.5 million after deducting discounts, commissions and deferred financing costs. The Company used the net proceeds to repay a portion of the outstanding indebtedness under the Facility and for general corporate purposes.

During April 2015, we issued an additional $225.0 million of Senior Notes and received net proceeds of $206.8 million after deducting discounts, commissions and other expenses. We used the net proceeds to repay a portion of the outstanding indebtedness under the Facility and for general corporate purposes. The additional $225.0 million of Senior Notes have identical terms to the initial $300.0 million of Senior Notes, other than the date of issue, the initial price, the first interest payment date and the first date from which interest accrued.

The Senior Notes mature on August 1, 2021. Interest is payable semi-annually in arrears each February 1 and August 1 commencing on February 1, 2015 for the initial $300.0 million Senior Notes and August 1, 2015 for the additional $225.0 million Senior Notes. The Senior Notes are secured (subject to certain exceptions and permitted liens) by a first ranking fixed equitable charge on all shares held by us in our direct subsidiary, Kosmos Energy Holdings. The Senior Notes are currently guaranteed on a subordinated, unsecured basis by our existing restricted subsidiaries that guarantee the Facility and the Corporate Revolver, and, in certain circumstances, the Senior Notes will become guaranteed by certain of our other existing or future restricted subsidiaries.

At June 30, 2017, the estimated repayments of debt during the five fiscal year periods and thereafter are as follows:

	Payments Due by Year						
	Total	2017(2)	2018	2019	2020	2021	Thereafter
	(In thousands)						
Principal debt repayments(1)	$ 1,175,000	$ —	$ —	$ 50,377	$ 404,971	$ 719,652	$ —

(1) Includes the scheduled principal maturities for the $525.0 million aggregate principal amount of Senior Notes issued in August 2014 and April 2015 and the Facility. The scheduled maturities of debt related to the Facility are based on, as of June 30, 2017, our level of borrowings and our estimated future available borrowing base commitment levels in future periods. Any increases or decreases in the level of borrowings or increases or

decreases in the available borrowing base would impact the scheduled maturities of debt during the next five years and thereafter. As of June 30, 2017, there were no borrowings under the Corporate Revolver.

(2) Represents payments for the period July 1, 2017 through December 31, 2017.

Interest and other financing costs, net

Interest and other financing costs, net incurred during the periods is comprised of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In thousands)			
Interest expense	$ 22,792	$ 21,824	$ 45,973	$ 42,772
Amortization—deferred financing costs	2,551	2,551	5,102	5,102
Capitalized interest	(7,376)	(17,584)	(16,935)	(34,030)
Deferred interest	634	149	949	(258)
Interest income	(760)	(466)	(1,740)	(834)
Other, net	1,624	2,404	2,902	6,450
Interest and other financing costs, net	$ 19,465	$ 8,878	$ 36,251	$ 19,202

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8. Derivative Financial Instruments

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

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

Oil Derivative Contracts

The following table sets forth the volumes in barrels underlying the Company's outstanding oil derivative contracts and the weighted average Dated Brent prices per Bbl for those contracts as of June 30, 2017. Volumes and weighted average prices are net of any offsetting derivative contracts entered into.

			Weighted Average Dated Brent Price per Bbl					
Term	Type of Contract	MBbl	Deferred Premium Payable, Net	Swap	Sold Put	Floor	Ceiling	Call
2017:								
July — December	Swap with puts/calls	1,006	$ 2.13	$ 72.50	$ 55.00	$ —	$ —	$ 90.00
July — December	Swap with puts	1,006	—	64.95	50.00	—	—	—
July — December	Three-way collars	2,012	1.72	—	30.00	45.00	60.00	—
July — December	Sold calls(1)	1,000	—	—	—	—	85.00	—
2018:								
January — December	Three-way collars	2,913	$ 0.74	$ —	$ 41.57	$ 56.57	$ 65.90	$ —
January — December	Four-way collars	3,000	1.06	—	40.00	50.00	61.33	70.00
January — December	Sold calls(1)	2,000	—	—	—	—	65.00	—
2019:								

January — December	Sold calls(1)	913	$ —	$ —	$ —	$ —	$ 80.00	$ —

(1) Represents call option contracts sold to counterparties to enhance other derivative positions.

In July 2017, we entered into three-way collar contracts for 3.0 MMBbl from January 2019 through December 2019 with a weighted average floor price of $50.00 per barrel, a weighted average ceiling price of $61.67 per barrel and a weighted average sold put price of $40.00 per barrel. The contracts are indexed to Dated Brent prices.

Interest Rate Derivative Contracts

The following table summarizes our capped interest rate swaps whereby we pay a fixed rate of interest if LIBOR is below the cap, and pay the market rate less the spread between the cap (sold call) and the fixed rate of interest if LIBOR is above the cap as of June 30, 2017:

				Weighted Average	
Term	Type of Contract	Floating Rate	Notional (In thousands)	Swap	Sold Call
July 2017 — December 2018	Capped swap	1-month LIBOR	$ 200,000	1.23 %	3.00 %

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The following tables disclose the Company's derivative instruments as of June 30, 2017 and December 31, 2016 and gain/(loss) from derivatives during the three and six months ended June 30, 2017 and 2016, respectively:

Type of Contract	Balance Sheet Location	Estimated Fair Value Asset (Liability) June 30, 2017	December 31, 2016
		(In thousands)	
Derivatives not designated as hedging instruments:			
Derivative assets:			
Commodity(1)	Derivatives assets—current	$ 36,825	$ 31,698
Interest rate	Derivatives assets—current	216	—
Commodity(2)	Derivatives assets—long-term	10,015	3,226
Interest rate	Derivatives assets—long-term	412	582
Derivative liabilities:			
Commodity(3)	Derivatives liabilities—current	(2,932)	(19,163)
Interest rate	Derivatives liabilities—current	—	(529)
Commodity(4)	Derivatives liabilities—long-term	(3,318)	(14,123)
Total derivatives not designated as hedging instruments		$ 41,218	$ 1,691

(1) Includes net deferred premiums payable of $4.7 million and $3.9 million related to commodity derivative contracts as of June 30, 2017 and December 31, 2016, respectively.
(2) Includes net deferred premiums payable of $3.5 million and $2.5 million related to commodity derivative contracts as of June 30, 2017 and December 31, 2016, respectively.
(3) Includes zero and $30.9 thousand as of June 30, 2017 and December 31, 2016, respectively, which represents our provisional oil sales contract. Also includes net deferred premiums payable of $3.1 million and $6.2 million related to commodity derivative contracts as of June 30, 2017 and December 31, 2016, respectively.
(4) Includes net deferred premiums receivable of $0.5 million and net deferred premiums payable of $0.6 million related to commodity derivative contracts as of June 30, 2017 and December 31, 2016, respectively.

Type of Contract	Location of Gain/(Loss)	Amount of Gain/(Loss) Three Months Ended June 30, 2017	2016	Amount of Gain/(Loss) Six Months Ended June 30, 2017	2016
		(In thousands)			
Derivatives not designated as hedging instruments:					
Commodity(1)	Oil and gas revenue	$ (4,552)	$ (1,665)	$ (4,560)	$ (1,055)
Commodity	Derivatives, net	25,411	(54,988)	63,268	(50,643)
Interest rate	Interest expense	(92)	(898)	236	(3,476)

Total derivatives not designated as hedging instruments	$ 20,767	$ (57,551)	$ 58,944	$ (55,174)

(1) Amounts represent the change in fair value of our provisional oil sales contracts.

Offsetting of Derivative Assets and Derivative Liabilities

Our derivative instruments which are subject to master netting arrangements with our counterparties only have the right of offset when there is an event of default. As of June 30, 2017 and December 31, 2016, there was not an event of default and, therefore, the associated gross asset or gross liability amounts related to these arrangements are presented on the consolidated balance sheets.

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9. Fair Value Measurements

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

- Level 1 — quoted prices for identical assets or liabilities in active markets.
- Level 2 — quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs derived principally from or corroborated by observable market data by correlation or other means.
- Level 3 — unobservable inputs for the asset or liability. The fair value input hierarchy level to which an asset or liability measurement in its entirety falls is determined based on the lowest level input that is significant to the measurement in its entirety.

The following tables present the Company's assets and liabilities that are measured at fair value on a recurring basis as of June 30, 2017 and December 31, 2016, 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)			
June 30, 2017				
Assets:				
Commodity derivatives	$ —	$ 46,840	$ —	$ 46,840
Interest rate derivatives	—	628	—	628
Liabilities:				
Commodity derivatives	—	(6,250)	—	(6,250)
Interest rate derivatives	—	—	—	—
Total	$ —	$ 41,218	$ —	$ 41,218
December 31, 2016				

Assets:								
Commodity derivatives	$	—	$	34,924	$	—	$	34,924
Interest rate derivatives		—		582		—		582
Liabilities:								
Commodity derivatives		—		(33,286)		—		(33,286)
Interest rate derivatives		—		(529)		—		(529)
Total	$	—	$	1,691	$	—	$	1,691

The book values of cash and cash equivalents and restricted cash approximate fair value based on Level 1 inputs. Joint interest billings, oil sales and other receivables, and accounts payable and accrued liabilities approximate fair value due to the short-term nature of these instruments. Our long-term receivables, after any allowances for doubtful accounts, and other long-term assets approximate fair value. The estimates of fair value of these items are based on Level 2 inputs.

Commodity Derivatives

Our commodity derivatives represent crude oil four-way collars, three-way collars, put options, call options and swaps for notional barrels of oil at fixed Dated Brent oil prices. The values attributable to our oil derivatives are based on (i) the contracted notional volumes, (ii) independent active futures price quotes for Dated Brent, (iii) a credit-adjusted yield

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curve applicable to each counterparty by reference to the credit default swap ("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 commodity derivatives. See Note 8 — Derivative Financial Instruments for additional information regarding the Company's derivative instruments.

Provisional Oil Sales

The value attributable to the provisional oil sales derivative is based on (i) the sales volumes and (ii) the difference in the independent active futures price quotes for Dated Brent over the term of the pricing period designated in the sales contract and the spot price on the lifting date.

Interest Rate Derivatives

We enter into interest rate swaps, whereby the Company pays a fixed rate of interest and the counterparty pays a variable LIBOR-based rate. We also enter into capped interest rate swaps, whereby the Company pays a fixed rate of interest if LIBOR is below the cap, and pays the market rate less the spread between the cap and the fixed rate of interest if LIBOR is above the cap. 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.

Debt

The following table presents the carrying values and fair values at June 30, 2017 and December 31, 2016:

	June 30, 2017		December 31, 2016	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In thousands)			
Senior Notes	$ 505,612	$ 536,356	$ 503,716	$ 528,938
Facility	650,000	650,000	850,000	850,000
Total	$ 1,155,612	$ 1,186,356	$ 1,353,716	$ 1,378,938

The carrying value of our Senior Notes represents the principal amounts outstanding less unamortized discounts. The fair value of our Senior Notes is based on quoted market prices, which results in a Level 1 fair value measurement. The carrying value of the Facility approximates fair value since it is subject to short-term floating interest rates that approximate the rates available to us for those periods.

10. Equity-based Compensation

Restricted Stock Awards and Restricted Stock Units

We record equity-based compensation expense equal to the fair value of share-based payments over the vesting periods of the Long-Term Incentive Plan (“LTIP”) awards. We recorded compensation expense from awards granted under our LTIP of $10.5 million and $10.5 million during the three months ended June 30, 2017 and 2016, respectively, and $20.3 million and $21.2 million during the six months ended June 30, 2017 and 2016, respectively. The total tax benefit for the three months ended June 30, 2017 and 2016 was $3.5 million and $3.3 million, respectively, and $6.8 million and $6.9 million during the six months ended June 30, 2017 and 2016, respectively. Additionally, we recorded a net tax shortfall related to equity-based compensation of $3.0 million and $3.1 million for the three months ended June 30, 2017 and 2016, respectively, and $2.8 million and $4.3 million during the six months ended June 30, 2017 and 2016, respectively. The fair value of awards vested during the three months ended June 30, 2017 and 2016 was approximately $10.5 million and $7.7 million, respectively, and $19.3 million and $11.2 million during the six months ended June 30, 2017 and 2016, respectively. The Company granted both restricted stock awards and restricted stock units with service vesting criteria and granted both restricted stock awards and restricted stock units with a combination of market and service vesting criteria under the LTIP. Substantially all these awards vest over three or four year periods. Restricted stock awards

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are issued and included in the number of outstanding shares upon the date of grant and, if such awards are forfeited, they become treasury stock. Upon vesting, restricted stock units become issued and outstanding stock.

The following table reflects the outstanding restricted stock awards as of June 30, 2017:

	Service Vesting Restricted Stock Awards (In thousands)	Weighted-Average Grant-Date Fair Value
Outstanding at December 31, 2016	488	$ 8.83
Granted	—	—
Forfeited	—	—
Vested	(268)	8.97
Outstanding at June 30, 2017	220	8.64

The following table reflects the outstanding restricted stock units as of June 30, 2017:

	Service Vesting Restricted Stock Units (In thousands)	Weighted-Average Grant-Date Fair Value	Market / Service Vesting Restricted Stock Units (In thousands)	Weighted-Average Grant-Date Fair Value
Outstanding at December 31, 2016	4,160	$ 6.91	7,194	$ 12.29
Granted	1,898	6.40	2,153	9.50
Forfeited	(64)	7.60	(20)	11.53
Vested	(1,735)	7.48	(823)	15.44
Outstanding at June 30, 2017	4,259	6.44	8,504	11.28

As of June 30, 2017, total equity-based compensation to be recognized on unvested restricted stock awards and restricted stock units is $42.7 million over a weighted average period of 1.58 years. At June 30, 2017, the Company had approximately 3.2 million shares that remain available for issuance under the LTIP.

For restricted stock awards and restricted stock units with a combination of market and service vesting criteria, the number of common shares to be issued is determined by comparing the Company's total shareholder return with the total shareholder return of a predetermined group of peer companies over the performance period and can vest in up to 100% of the awards granted for restricted stock awards and up to 200% of the awards granted for restricted stock units. The grant date fair value was $9.45 per award for restricted stock awards and ranged from $4.83 to $15.81 per award for restricted stock units. The Monte Carlo simulation model utilizes multiple input variables that determine the probability of satisfying the market condition stipulated in the award grant and calculates the fair value of the award. The expected volatility utilized in the model was estimated using our historical volatility and the historical volatilities of our peer companies and was 55.0% for the restricted stock awards and ranged from 44.0% to 54.0% for restricted stock units. The risk-free interest rate was based on the U.S. treasury rate for a term commensurate with the expected life of the grant and was 0.5% for restricted stock awards and ranged from 0.5% to 1.4% for restricted stock units.

11. Income Taxes

We evaluate our estimated annual effective income tax rate based on current and forecasted business results and enacted tax laws on a quarterly basis and apply this tax rate to our ordinary income or loss to calculate our estimated tax expense or benefit. The Company excludes zero tax rate and tax exempt jurisdictions from our evaluation of the estimated annual effective income tax rate. The tax effect of discrete items are recognized in the period in which they occur at the applicable statutory tax rate.

Income tax expense (benefit) was $23.7 million and $(15.5) million for the three months ended June 30, 2017 and 2016, respectively, and $45.9 million and $(17.6) million for the six months ended June 30, 2017 and 2016, respectively. The income tax provision consists of United States and Ghanaian income and Texas margin taxes. Our operations in other foreign jurisdictions have a 0% effective tax rate because they reside in countries with a 0% statutory

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rate or we have incurred losses in those countries and have full valuation allowances against the corresponding net deferred tax assets.

Income (loss) before income taxes is composed of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In thousands)			
Bermuda	$ (16,759)	$ (15,427)	$ (32,940)	$ (31,223)
United States	1,382	2,219	2,794	4,315
Foreign—other	30,649	(110,660)	38,754	(157,975)
Income (loss) before income taxes	$ 15,272	$ (123,868)	$ 8,608	$ (184,883)

Our effective tax rate for the three months ended June 30, 2017 and 2016 is 155% and 13%, respectively. For the six months ended, June 30, 2017 and 2016, our effective tax rate was 533% and 10%, respectively. The effective tax rate is impacted by the effect of equity-based compensation tax shortfalls and windfalls equal to the difference between the income tax benefit recognized for financial statement purposes and the income tax benefit realized for tax return purposes and by non-deductible expenditures associated with the damage to the turret bearing, which we expect to recover from insurance proceeds. Any such insurance recoveries would not be subject to income tax.

The Company files income tax returns in all jurisdictions where such requirements exist, however, our primary tax jurisdictions are Ghana and the United States. The Company is open to Ghanaian federal income tax examinations for tax years 2014 through 2016 and in the United States, to federal income tax examinations for tax years 2013 through 2016.

As of June 30, 2017, the Company had no material uncertain tax positions. The Company's policy is to recognize potential interest and penalties related to income tax matters in income tax expense.

12. Net Income (Loss) Per Share

The following table is a reconciliation between net income and the amounts used to compute basic and diluted net income per share and the weighted average shares outstanding used to compute basic and diluted net income (loss) per share:

	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
Numerator:				
Net loss	$ (8,467)	$ (108,324)	$ (37,308)	$ (167,317)
Basic income allocable to participating securities(1)	—	—	—	—
Basic net loss allocable to common shareholders	(8,467)	(108,324)	(37,308)	(167,317)
Diluted adjustments to income allocable to participating securities(1)	—	—	—	—
Diluted net loss allocable to common shareholders	$ (8,467)	$ (108,324)	$ (37,308)	$ (167,317)
Denominator:				
Weighted average number of shares outstanding:				
Basic	387,952	384,918	387,634	384,676
Restricted stock awards and units(1)(2)	—	—	—	—
Diluted	387,952	384,918	387,634	384,676
Net loss per share:				
Basic	$ (0.02)	$ (0.28)	$ (0.10)	$ (0.43)
Diluted	$ (0.02)	$ (0.28)	$ (0.10)	$ (0.43)

(1) Our service vesting restricted stock awards represent participating securities because they participate in non-forfeitable dividends with common equity owners. Income allocable to participating securities represents the distributed and undistributed earnings attributable to the participating securities. Our restricted stock awards with market and service vesting criteria and all restricted stock units are not considered to be participating securities and, therefore, are excluded from the basic net income (loss) per common share calculation. Our service vesting restricted stock awards do not participate in undistributed net losses because they are not contractually obligated to do so and, therefore, are excluded from the basic net income (loss) per common share calculation in periods we are in a net loss position.

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(2) We excluded outstanding restricted stock awards and units of 13.0 million and 12.3 million for the three and six months ended June 30, 2017 and 2016, respectively, from the computations of diluted net income per share because the effect would have been anti-dilutive.

13. Commitments and Contingencies

From time to time, we are involved in litigation, regulatory examinations and administrative proceedings primarily arising in the ordinary course of our business in jurisdictions in which we do business. Although the outcome of these matters cannot be predicted with certainty, management believes none of these matters, either individually or in the aggregate, would have a material effect upon the Company's financial position; however, an unfavorable outcome could have a material adverse effect on our results from operations for a specific interim period or year.

We currently have a commitment to drill two exploration wells in Mauritania. In Mauritania, our partner is obligated to fund our share of the cost of the exploration wells, subject to their maximum $221 million cumulative exploration and appraisal carry covering both our Mauritania and Senegal blocks. In Sao Tome and Principe and Western Sahara, we have 3D seismic requirements of 4,750 square kilometers and 5,000 square kilometers, respectively. Additionally, in Morocco certain geological studies are also required.

In January 2017, Kosmos Energy Ventures ("KEV"), a subsidiary of Kosmos Energy Ltd., elected to cancel the fourth year option of the Atwood Achiever drilling rig contract and revert to the original day rate of approximately $0.6 million per day and original agreement end date in November 2017. During the first quarter of 2017, KEV made a rate recovery payment of $48.1 million representing the difference between the original day rate and the amended day rate multiplied by the number of days from the amendment effective date to the date the election was exercised plus certain administrative costs.

Future minimum rental commitments under our leases at June 30, 2017, are as follows:

	Payments Due By Year(1)						
	Total	2017(2)	2018	2019	2020	2021	Thereafter
	(In thousands)						
Operating leases(3)	$ 10,883	$ 2,278	$ 4,600	$ 3,940	$ 65	$ —	$ —
Atwood Achiever drilling rig contract	80,325	80,325	—	—	—	—	—

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

(2) Represents payments for the period from July 1, 2017 through December 31, 2017.

(3) Primarily relates to corporate office and foreign office leases.

14. Additional Financial Information

Accrued Liabilities

Accrued liabilities consisted of the following:

	June 30, 2017	December 31, 2016
	(In thousands)	
Accrued liabilities:		
Exploration, development and production	$ 149,851	$ 76,194
General and administrative expenses	16,847	31,243
Interest	19,511	17,247
Income taxes	—	2,579
Taxes other than income	2,815	1,914
Other	1,237	529
	$ 190,261	$ 129,706

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Other Income, Net

Other income, net consisted of $10.2 million and zero of Loss of Production Income ("LOPI") proceeds, net related to the turret bearing issue on the Jubilee FPSO for the three months ended June 30, 2017 and 2016, respectively and $58.7 million and zero for the six months ended June 30, 2017 and 2016, respectively. Our LOPI coverage for this incident ended in May 2017.

Facilities Insurance Modifications, Net

Facilities insurance modifications, net consists of costs associated with the conversion of the Jubilee FPSO to a permanently spread moored facility, net of related insurance proceeds.

Other Expenses, Net

Other expenses, net incurred during the period is comprised of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In thousands)			
Inventory write-off	$ 547	$ (532)	$ 547	$ 15,177
Gain on insurance settlements	—	—	(461)	(956)
Disputed charges and related costs	1,209	—	2,439	—
Loss on equity method investment	6,426	—	6,426	—
Other, net	252	362	245	342
Other expenses, net	$ 8,434	$ (170)	$ 9,196	$ 14,563

The disputed charges and related costs are expenditures arising from Tullow Ghana Limited's contract with Seadrill for use of the West Leo drilling rig once partner-approved 2016 work program objectives were concluded. Tullow has charged such expenditures to the Deepwater Tano ("DT") joint account. Kosmos disputes that these expenditures are properly chargeable to the DT joint account on the basis that the Seadrill West Leo drilling rig contract was not approved by the DT operating committee pursuant to the DT Joint Operating Agreement.

During the three and six month periods ended June 30, 2017, we recognized $6.4 million related to our share of losses related to our equity investment in KBSL.

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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, 2016, included in our annual report on Form 10-K along with the section Management’s Discussion and Analysis of financial condition and Results of Operations contained in such annual report. Any terms used but not defined in the following discussion have the same meaning given to them in the annual report. Our discussion and analysis includes forward-looking statements that involve risks and uncertainties and should be read in conjunction with “Risk Factors” under Item 1A of this report and in the annual report, 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 a leading independent oil and gas exploration and production company focused on frontier and emerging areas along the Atlantic Margins. Our assets include existing production and development projects offshore Ghana, large discoveries and significant further hydrocarbon exploration potential offshore Mauritania and Senegal, as well as exploration licenses with significant hydrocarbon potential offshore Sao Tome and Principe, Suriname, Morocco and Western Sahara.

Recent Developments

Corporate

In August 2017, we announced our intention to pursue a secondary listing on the standard segment of the Main Market on the London Stock Exchange (“LSE”). The listing is expected to broaden Kosmos’ international investor base and provide access to an additional pool of capital. The listing process is expected to be completed late in the third quarter of 2017.

Ghana

Jubilee

Kosmos and its partners have determined the preferred long-term solution to the turret bearing issue is to convert the FPSO to a permanently spread moored facility, with offloading through a new deepwater Catenary Anchor Leg Mooring (“CALM”) buoy. The Jubilee turret remediation work is progressing as planned and the FPSO spread-mooring at its current heading was completed in February 2017. This allowed the tug boats previously required to hold the vessel on a fixed heading to be removed, significantly reducing the cost and complexity of the current operation. The next phase of the remediation work involves modifications to the turret for long-term spread-moored operations. At present, the partnership is evaluating the optimal long-term heading. The partners and the government of Ghana have agreed on the need to stabilize the turret bearing and a shutdown is being planned in late 2017 to execute this workscope. Planning for the rotation of the vessel and the installation of a deepwater CALM buoy is ongoing and it is anticipated that this work will be executed in two stages in 2018 and 2019, subject to final decisions and government approval. Total shutdown duration, for stabilization, rotation and offloading system installation, is not expected to exceed 12 weeks as previously forecast by the Operator.

The financial impact of lower Jubilee production as well as the additional expenditures associated with the damage to the turret bearing is being mitigated through a combination of the comprehensive Hull and Machinery insurance (“H&M”), procured by the operator, Tullow, on behalf of the Jubilee Unit partners, and the corporate Loss of Production Income (“LOPI”) insurance procured by Kosmos. Our LOPI coverage for this incident ended in May 2017 and final claim amounts have been approved with remaining cash proceeds expected to be received in early August 2017.

Work is progressing with the government of Ghana and Jubilee partners to update the Greater Jubilee Full Field Development Plan (“GJFFDP”). This plan, which is expected to increase proved reserves and extend the field production profile, has been optimized to reduce overall capital expenditures to reflect the current oil market. The partners remain on track to resubmit the GJFFDP to the government of Ghana with approval expected later in the year and drilling to commence in 2018.

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Tweneboa, Enyenra and Ntomme ("TEN")

In June 2017, performance trials have shown the FPSO can operate in excess of its design capacity of 80,000 bopd with short term tests of up to 100,000 bopd being achieved through the FPSO vessel production facilities. However, no new wells can be drilled until after the previously disclosed ITLOS ruling which is expected in September 2017. Production from TEN in the first half of 2017 averaged approximately 48,000 bopd and is on track to achieve or exceed the operator's 2017 guidance of 50,000 bopd. After resuming drilling, the TEN fields are expected to increase production towards FPSO capacity of 80,000 bopd as development progresses, subject to the maritime boundary dispute between Cote d'Ivoire and Ghana.

Senegal (Kosmos BP Senegal Limited ("KBSL") – equity method investment)

In the second quarter of 2017, Kosmos agreed to withdraw the exercise of our call option upon completion of an agreement between BP and Timis Corporation Limited ("Timis") by which BP acquired Timis' entire 30% participating interest in the Senegal Blocks. Kosmos and BP anticipate that the KBSL joint venture will be unwound, with BP receiving from KBSL a 30% participating interest in the Senegal Blocks and then surrendering its shareholding interest in KBSL, subject to approval of the Senegalese government. Upon completion of the unwind, it is expected that the cap on exploration and appraisal carry will be increased by $7 million.

In May 2017, we announced the Yakaar-1 exploration well, located in the Cayar Offshore Profond block offshore Senegal, made a major gas discovery. Located approximately 60 miles northwest of Dakar in approximately 2,600 meters of water, the Yakaar-1 exploration well was drilled to a total depth of approximately 4,900 meters. The well intersected a gross hydrocarbon column of 120 meters (394 feet) in three pools within the primary Lower Cenomanian objective and encountered 45 meters (148 feet) of net pay.

Mauritania

In June 2017, we entered into a farm-in agreement with Tullow Mauritania Limited, a subsidiary of Tullow Oil plc ("Tullow"), to acquire a 15% non-operated participating interest in Block C18 offshore Mauritania. Based on the terms of the agreement, we will reimburse a portion of past and interim period costs and partially carry Tullow's share of a planned 3D seismic program (up to $2.1 million net to Kosmos). We will also pay Tullow $2.5 million by the end of the initial phase of the exploration period for additional carry of seismic and other joint account costs. Certain governmental approvals and processes are still required to be completed before this agreement is effective.

Morocco

In June 2017, we completed a 3D seismic survey of approximately 3,000 square kilometers over the Essaouira Offshore block in the Agadir Basin.

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Results of Operations

All of our results, as presented in the table below, represent operations in Ghana. Certain operating results and statistics for the three and six months ended June 30, 2017 and 2016 are included in the following table:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In thousands, except per barrel data)			
Sales volumes:				
MBbl	2,915	948	4,891	2,844
Revenues:				
Oil and gas sales	$ 136,363	$ 45,506	$ 239,795	$ 107,631
Average sales price per Boe	46.78	48.00	49.03	37.84
Costs:				
Oil and gas production, excluding workovers	$ 21,045	$ 32,687	$ 40,992	$ 62,062
Oil and gas production, workovers	559	(6)	498	11
Total oil and gas production costs	$ 21,604	$ 32,681	$ 41,490	$ 62,073
Depletion and depreciation	$ 72,441	$ 16,927	$ 107,419	$ 48,193
Average cost per Boe:				
Oil and gas production, excluding workovers	$ 7.22	$ 34.48	$ 8.38	$ 21.82
Oil and gas production, workovers	0.19	(0.01)	0.10	—
Total oil production costs	7.41	34.47	8.48	21.82
Depletion and depreciation	24.85	17.86	21.96	16.95
Oil and gas production cost and depletion costs	$ 32.26	$ 52.33	$ 30.44	$ 38.77

The following table shows the number of wells in the process of being drilled or in active completion stages, and the number of wells suspended or waiting on completion as of June 30, 2017:

	Actively Drilling or Completing				Wells Suspended or Waiting on Completion			
	Exploration		Development		Exploration		Development	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Ghana								
Jubilee Unit	—	—	—	—	—	—	2	0.48

West Cape Three Points	—	—	—	—	9	2.78	—	—
TEN	—	—	—	—	—	—	5	0.85
Deepwater Tano	—	—	—	—	1	0.18	—	—
Mauritania								
C8	—	—	—	—	3	0.84	—	—
Senegal (KBSL - equity method investment)								
Saint Louis Offshore Profond	—	—	—	—	1	0.30	—	—
Cayar Profond	—	—	—	—	2	0.60	—	—
Total	—	—	—	—	16	4.70	7	1.33

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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 June 30, 2017 compared to three months ended June 30, 2016

	Three Months Ended June 30, 2017	2016	Increase (Decrease)
	(In thousands)		
Revenues and other income:			
Oil and gas revenue	$ 136,363	$ 45,506	$ 90,857
Other income, net	10,161	170	9,991
Total revenues and other income	146,524	45,676	100,848
Costs and expenses:			
Oil and gas production	21,604	32,681	(11,077)
Facilities insurance modifications, net	(2)	—	(2)
Exploration expenses	19,982	36,402	(16,420)
General and administrative	14,739	19,838	(5,099)
Depletion and depreciation	72,441	16,927	55,514
Interest and other financing costs, net	19,465	8,878	10,587
Derivatives, net	(25,411)	54,988	(80,399)
Other expenses, net	8,434	(170)	8,604
Total costs and expenses	131,252	169,544	(38,292)
Income (loss) before income taxes	15,272	(123,868)	139,140
Income tax expense (benefit)	23,739	(15,544)	39,283
Net loss	$ (8,467)	$ (108,324)	$ 99,857

Oil and gas revenue. Oil and gas revenue increased by $90.9 million as a result of three cargos sold during the three months ended June 30, 2017, compared to one cargo sold during the three months ended June 30, 2016. We lifted and sold 2,915 MBbl at an average realized price per barrel of $46.78 during the three months ended June 30, 2017 and 948 MBbl at an average realized price per barrel of $48.00 during the three months ended June 30, 2016.

Other income, net. Other income, net increased by $10.0 million as we recognized $10.2 million of LOPI proceeds, net during the three months ended June 30, 2017 related to the turret bearing issue on the Jubilee FPSO. The LOPI claim was finalized in June 2017.

Oil and gas production. Oil and gas production costs decreased by $11.1 million during the three months ended June 30, 2017, as compared to the three months ended June 30, 2016 as a result of insurance proceeds recognized related to increased costs due to turret issues during the three months ended June 30, 2017 as well as accrual adjustments from the Jubilee and TEN fields operator.

Facilities insurance modifications, net. During the three months ended June 30, 2017, we incurred $2.7 million of facilities insurance modifications costs associated with the long-term solution to the turret bearing issue. These costs were mitigated by $2.7 million of hull and machinery insurance proceeds received during the three months ended June 30, 2017.

Exploration expenses. Exploration expenses decreased by $16.4 million during the three months ended June 30, 2017, as compared to the three months ended June 30, 2016. The change is primarily a result of a decrease in geological and geophysical costs during the three months ended June 30, 2017 as compared with the three months ended June 30, 2016 as well as stacked rig costs associated with the Atwood Achiever. The decrease was partially mitigated by an increase in seismic and unsuccessful well costs.

General and administrative. General and administrative costs decreased by $5.1 million during the three months ended June 30, 2017, as compared with the three months ended June 30, 2016. The decrease is primarily a result of carried costs associated with the BP transactions and accrual adjustments from the Jubilee and TEN fields operator.

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Depletion and depreciation. Depletion and depreciation increased $55.5 million during the three months ended June 30, 2017, as compared with the three months ended June 30, 2016. The increase is primarily a result of depletion recognized related to the sale of three cargos of oil, including one TEN cargo, during the three months ended June 30, 2017, as compared to one Jubilee cargo during the three months ended June 30, 2016. In addition, the depletion rate is higher as a result of a decrease in recognized proved reserves associated with the Jubilee Field in the fourth quarter of 2016 and a higher depletion rate for the TEN fields.

Interest and other financing costs, net. Interest and other financing costs, net increased $10.6 million primarily a result of the TEN fields coming online in August 2016, which resulted in a $10.2 million decrease in capitalized interest.

Derivatives, net. During the three months ended June 30, 2017 and 2016, we recorded a gain of $25.4 million and a loss of $55.0 million, respectively, on our outstanding hedge positions. The gain and loss recorded were a result of changes in the forward curve of oil prices during the respective periods.

Other expenses, net. Other expenses, net increased $8.6 million primarily related to a $6.4 million loss on equity method investment in KBSL and an increase in arbitration related legal fees.

Income tax expense (benefit). The Company’s effective tax rates for the three months ended June 30, 2017 and 2016 were 155% and 13%, respectively. The effective tax rates for the periods presented were impacted by losses, primarily related to exploration expenses, incurred in jurisdictions in which we are not subject to taxes and losses incurred in jurisdictions in which we have valuation allowances against our deferred tax assets and therefore we do not realize any tax benefit on such expenses or losses. The effective tax rate in Ghana is impacted by the timing of non-deductible expenditures incurred associated with the damage to the turret bearing which we expect to recover from insurance proceeds. Any such insurance recoveries would not be subject to income tax. Income tax expense increased $39.3 million during the three months ended June 30, 2017, as compared with June 30, 2016, primarily as a result of higher oil revenue in Ghana and mark to market gains on our oil derivatives, offset by depletion and depreciation expense associated with TEN production during the period ended June 30, 2017.

Six months ended June 30, 2017 compared to six months ended June 30, 2016

	Six Months Ended June 30,		Increase
	2017	2016	(Decrease)
	(In thousands)		
Revenues and other income:			

Oil and gas revenue	$ 239,795	$ 107,631	$ 132,164
Other income, net	58,695	178	58,517
Total revenues and other income	298,490	107,809	190,681
Costs and expenses:			
Oil and gas production	41,490	62,073	(20,583)
Facilities insurance modifications, net	2,572	—	2,572
Exploration expenses	125,696	60,260	65,436
General and administrative	30,526	37,758	(7,232)
Depletion and depreciation	107,419	48,193	59,226
Interest and other financing costs, net	36,251	19,202	17,049
Derivatives, net	(63,268)	50,643	(113,911)
Other expenses, net	9,196	14,563	(5,367)
Total costs and expenses	289,882	292,692	(2,810)
Income (loss) before income taxes	8,608	(184,883)	193,491
Income tax expense (benefit)	45,916	(17,566)	63,482
Net loss	$ (37,308)	$ (167,317)	$ 130,009

Oil and gas revenue. Oil and gas revenue increased by $132.2 million as a result of five cargos sold during the six months ended June 30, 2017, compared to three cargos sold during the six months ended June 30, 2016 at a higher average realized price. We lifted and sold 4,891 MBbl at an average realized price per barrel of $49.03 during the six

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months ended June 30, 2017 and 2,844 MBbl at an average realized price per barrel of $37.84 during the six months ended June 30, 2016.

Other income, net. Other income, net increased by $58.5 million as we recognized $58.7 million of LOPI proceeds, net during the six months ended June 30, 2017 related to the turret bearing issue on the Jubilee FPSO compared to no proceeds in the previous period. The LOPI claim was finalized in June 2017.

Oil and gas production. Oil and gas production costs decreased by $20.6 million during the six months ended June 30, 2017, as compared to the six months ended June 30, 2016 as a result of finalized LOPI claim insurance proceeds recognized related to increased costs due to turret issues during the six months ended June 30, 2017 as well as accrual adjustments from the Jubilee and TEN fields operator.

Facilities insurance modifications, net. During the six months ended June 30, 2017, we incurred $10.2 million of facilities insurance modifications costs associated with the long-term solution to the turret bearing issue. These costs were mitigated by $7.6 million of hull and machinery insurance proceeds received during the six months ended June 30, 2017.

Exploration expenses. Exploration expenses increased by $65.4 million during the six months ended June 30, 2017, as compared to the six months ended June 30, 2016. The increase is primarily a result of a $48.1 million cancellation payment related to the exercise of our election to cancel the fourth year option of the Atwood Achiever drilling rig contract and an increase of $25.7 million of stacked rig costs associated with the Atwood Achiever incurred during the six months ended June 30, 2017 as compared with the six months ended June 30, 2016. These increases were partially mitigated by a decrease of $12.6 million in geological and geophysical costs.

General and administrative. General and administrative costs decreased by $7.2 million during the six months ended June 30, 2017, as compared with the six months ended June 30, 2016. The decrease is primarily a result of carried costs associated with the BP transactions, accrual adjustments from the Jubilee and TEN fields operator, and to a lesser extent a decrease in non-cash stock-based compensation.

Depletion and depreciation. Depletion and depreciation increased $59.2 million during the six months ended June 30, 2017, as compared with the six months ended June 30, 2016. The increase is primarily a result of depletion recognized related to the sale of five cargos of oil during the six months ended June 30, 2017, as compared to three cargos during the six months ended June 30, 2016. In addition, the depletion rate is higher as a result of a decrease in recognized proved reserves associated with the Jubilee Field in the fourth quarter of 2016 and a higher depletion rate for the TEN fields.

Interest and other financing costs, net. Interest and other financing costs, net increased $17.0 million primarily a result of the TEN fields coming online in August 2016, which resulted in a $17.1 million decrease in capitalized interest.

Derivatives, net. During the six months ended June 30, 2017 and 2016, we recorded gain of $63.3 million and a loss of $50.6 million, respectively, on our outstanding hedge positions. The gain and loss recorded were a result of changes in the forward curve of oil prices during the respective periods.

Other expenses, net. Other expenses, net decreased $5.4 million primarily due to a $15.2 million impairment of inventory recorded during the six months ended June 30, 2016, compared to a $6.4 million loss recognized on our equity method investment in KBSL and arbitration related legal fees recorded during the six months ended, June 30, 2017.

Income tax expense (benefit). The Company’s effective tax rates for the six months ended June 30, 2017 and 2016 were 533% and 10%, respectively. The effective tax rates for the periods presented were impacted by losses, primarily related to exploration expenses, incurred in jurisdictions in which we are not subject to taxes and losses incurred in jurisdictions in which we have valuation allowances against our deferred tax assets and therefore we do not realize any tax benefit on such expenses or losses. The effective tax rate in Ghana is impacted by the timing of non-deductible expenditures incurred associated with the damage to the turret bearing which we expect to recover from insurance proceeds. Any such insurance recoveries would not be subject to income tax. Income tax expense increased $63.5 million during the six months ended June 30, 2017, as compared with June 30, 2016, primarily as a result of higher oil revenue in Ghana and mark to market gains on our oil derivatives, offset by depletion and depreciation expense associated with TEN production during the period ended June 30, 2017.

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Liquidity and Capital Resources

We are actively engaged in an ongoing process of anticipating and meeting our funding requirements related to exploring for and developing oil and natural gas resources along the Atlantic Margins. We have historically met our funding requirements through cash flows generated from our operating activities and obtained additional funding from issuances of equity and debt as well as partner carries. In relation to cash flow generated from our operating activities, if we are unable to continuously export associated natural gas in large quantities, which causes potential production restraints, then the Company’s cash flows from operations will be adversely affected. In the past we have experienced equipment failures on the FPSOs, and we are currently working to remediate the turret bearing issue on the Jubilee FPSO. This equipment downtime negatively impacted oil production and we are in the process of repairing the current mechanical issues and implementing a long-term solution for the turret issue.

While we are presently in a strong financial position, a future decline in oil prices, if prolonged, could negatively impact our ability to generate sufficient operating cash flows to meet our funding requirements. It could also impact the borrowing base available under the Facility or the related debt covenants. Commodity prices are volatile and future prices cannot be accurately predicted. We maintain a hedging program to partially mitigate the price volatility. Our investment decisions are based on longer-term commodity prices based on the long-term nature of our projects and development plans. Also, BP has agreed to partially carry our exploration, appraisal and development program in Mauritania and Senegal over the next several years. Current commodity prices, our hedging program, partner carries and our current liquidity position support our capital program for 2017, which is based on our development plans for Ghana and our exploration and appraisal program.

Our future financial condition and liquidity will be impacted by, among other factors, 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, the reliability of our oil and gas production facilities, our ability to continuously export oil and gas, our ability to secure and maintain partners and their alignment with respect to capital plans, the actual cost of exploration, appraisal and development of our oil and natural gas assets, and coverage of any claims under our insurance policies.

In March 2017, following the lender’s semi-annual redetermination, the borrowing base under our Facility was $1.3 billion (effective April 1, 2017). The borrowing base calculation includes value related to the Jubilee and TEN fields.

Sources and Uses of Cash

The following table presents the sources and uses of our cash and cash equivalents for the six months ended June 30, 2017 and 2016:

	Six Months Ended June 30,	
	2017	2016

	(In thousands)	
Sources of cash, cash equivalents and restricted cash:		
Net cash used in operating activities	$ (17,514)	$ (24,078)
Borrowings under long-term debt	—	325,000
Proceeds on sale of assets	222,068	196
	204,554	301,118
Uses of cash, cash equivalents and restricted cash:		
Oil and gas assets	42,805	417,704
Other property	1,454	601
Payments on long-term debt	200,000	—
Purchase of treasury stock	1,945	1,798
	246,204	420,103
Decrease in cash, cash equivalents and restricted cash	$ (41,650)	$ (118,985)

Net cash provided by (used in) operating activities. Net cash used in operating activities for the six months ended June 30, 2017 was $17.5 million compared with net cash used in operating activities for the six months ended June 30, 2016 of $24.1 million. The decrease in cash used in operating activities in the six months ended June 30, 2017 when

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compared to the same period in 2016 is primarily a result of an increase in oil and gas revenue and LOPI proceeds, net partially offset by an increase in exploration expense related to the stacked rig costs and rig option cancellation payment as well as a decrease in derivative cash settlements.

The following table presents our net debt and liquidity as of June 30, 2017:

	June 30, 2017
	(In thousands)
Cash and cash equivalents	$ 162,474
Restricted cash	69,071
Senior Notes at par	525,000
Drawings under the Facility	650,000
Net debt	$ 943,455
Availability under the Facility	$ 650,800
Availability under the Corporate Revolver	$ 400,000
Available borrowings plus cash and cash equivalents (“liquidity”)	$ 1,213,274

Capital Expenditures and Investments

We expect to incur capital costs as we:

· fund asset integrity projects at Jubilee;

· execute exploration and appraisal activities in our Senegal and Mauritania license areas; and

· acquire and analyze seismic, perform new ventures and manage our rig activities.

We have relied on a number of assumptions in budgeting for our future activities. These include the number of wells we plan to drill, our participating and carried interests in our prospects including disproportionate payment amounts, the costs involved in developing or participating in the development of a prospect, the timing of third-party projects, our ability to utilize our available drilling rig capacity, the availability of suitable equipment and qualified personnel and our cash flows from operations. We also evaluate potential corporate and asset acquisition opportunities to support and expand our asset portfolio which may impact our budget assumptions. 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 market conditions deteriorate; or one or more of our assumptions proves to be incorrect or if we choose to expand our acquisition, exploration, appraisal, development efforts or any other activity more rapidly than we presently anticipate. We may decide to raise additional funds before we need them if the conditions for raising capital are favorable. We may seek to sell equity or debt securities or obtain additional bank credit facilities. The sale of equity securities could result in dilution to our shareholders. The incurrence of additional indebtedness could result in increased fixed obligations and additional covenants that could restrict our operations.

2017 Capital Program

We estimate we will spend approximately $100 million of capital, net of carry amounts related to the Mauritania and Senegal transactions with BP, for the year ending December 31, 2017. Through June 30, 2017, we have spent approximately $156 million which was offset by the initial proceeds from the BP transaction of $222 million resulting in a credit to our capital budget of $66 million.

The ultimate amount of capital we will spend may fluctuate materially based on market conditions and the success of our drilling results among other factors. We resumed our previously suspended drilling program during the first quarter of 2017. Our future financial condition and liquidity will be impacted by, among other factors, our level of production of oil and the prices we receive from the sale of oil, our ability to effectively hedge future production volumes, 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, our partners' alignment with respect to capital plans, and the actual cost of exploration, appraisal and development of our oil and natural gas assets, and coverage of any claims under our insurance policies.

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Significant Sources of Capital

Facility

In March 2014, we amended and restated the commercial debt facility (the "Facility") with a total commitment of $1.5 billion from a number of financial institutions. The Facility supports our oil and gas exploration, appraisal and development programs and corporate activities.

In March 2017, following the lender's semi-annual redetermination, the borrowing base under our Facility was $1.3 billion (effective April 1, 2016). The borrowing base calculation includes value related to the Jubilee and TEN fields.

We were in compliance with the financial covenants contained in the Facility as of March 31, 2017 (the most recent assessment date). The Facility contains customary cross default provisions.

Corporate Revolver

In June 2015, we amended and restated the Corporate Revolver from a number of financial institutions, increasing the borrowing capacity to $400.0 million. The Corporate Revolver is available for all subsidiaries for general corporate purposes and for oil and gas exploration, appraisal and development programs.

As of June 30, 2017, there were no borrowings outstanding under the Corporate Revolver and the undrawn availability under the Corporate Revolver was $400.0 million.

We were in compliance with the financial covenants contained in the Corporate Revolver as of March 31, 2017 (the most recent assessment date). The Corporate Revolver contains customary cross default provisions.

Revolving Letter of Credit Facility

In July 2016, we amended and restated the revolving letter of credit facility agreement ("LC Facility"), extending the maturity date to July 2019. During the first quarter of 2017, the LC Facility size was $115.0 million. In April 2017, we reduced the size of our LC Facility to $70 million. As of June 30, 2017, there were seven outstanding letters of credit totaling $57.7 million under the LC Facility. The LC Facility contains customary cross default provisions.

7.875% Senior Secured Notes due 2021

During August 2014, we issued $300.0 million of Senior Notes and received net proceeds of approximately $292.5 million after deducting discounts, commissions and deferred financing costs. The Company used the net proceeds to repay a portion of the outstanding indebtedness under the Facility and for general corporate purposes.

During April 2015, we issued an additional $225.0 million Senior Notes and received net proceeds of $206.8 million after deducting discounts, commissions and other expenses. We used the net proceeds to repay a portion of the outstanding indebtedness under the Facility and for general corporate purposes. The additional $225.0 million of Senior Notes have identical terms to the initial $300.0 million Senior Notes, other than the date of issue, the initial price, the first interest payment date and the first date from which interest accrued.

The Senior Notes mature on August 1, 2021. Interest is payable semi-annually in arrears each February 1 and August 1 commencing on February 1, 2015 for the initial $300.0 million Senior Notes and August 1, 2015 for the additional $225.0 million Senior Notes. The Senior Notes are secured (subject to certain exceptions and permitted liens) by a first ranking fixed equitable charge on all shares held by us in our direct subsidiary, Kosmos Energy Holdings. The Senior Notes are currently guaranteed on a subordinated, unsecured basis by our existing restricted subsidiaries that guarantee the Facility and the Corporate Revolver, and, in certain circumstances, the Senior Notes will become guaranteed by certain of our other existing or future restricted subsidiaries. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources" section of our annual report on Form 10-K for the terms of the Senior Notes.

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Contractual Obligations

The following table summarizes by period the payments due for our estimated contractual obligations as of June 30, 2017:

	Payments Due By Year(5)						
	Total	2017(6)	2018	2019	2020	2021	Thereafter
	(In thousands)						
Principal debt repayments(1)	$ 1,175,000	$ —	$ —	$ 50,377	$ 404,971	$ 719,652	$ —
Interest payments on long-term debt(2)	309,966	43,272	81,702	74,398	65,341	45,253	—
Operating leases(3)	10,883	2,278	4,600	3,940	65	—	—
Atwood Achiever drilling rig contract(4)	80,325	80,325	—	—	—	—	—

(1) Includes the scheduled principal maturities for the $525.0 million aggregate principal amount of Senior Notes issued in August 2014 and April 2015 and the Facility. The scheduled maturities of debt related to the Facility are based on, as of June 30, 2017, our level of borrowings and our estimated future available borrowing base commitment levels in future periods. Any increases or decreases in the level of borrowings or increases or decreases in the available borrowing base would impact the scheduled maturities of debt during the next five years and thereafter. As of June 30, 2017, there were no borrowings under the Corporate Revolver.

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

(3) Primarily relates to corporate office and foreign office leases.

(4) In January 2017, Kosmos Energy Ventures (“KEV”) exercised its option to cancel the fourth year and revert to the original day rate of approximately $0.6 million per day and original agreement end date in November 2017. Commitments were calculated using the original day rate of $0.6 million, excluding applicable taxes.

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

(6) Represents the period from July 1, 2017 through December 31, 2017.

We currently have a commitment to drill two exploration wells in Mauritania. In Mauritania, our partner is obligated to fund our share of the cost of the exploration wells, subject to their maximum $221 million cumulative exploration and appraisal carry covering both our Mauritania and Senegal blocks. In Sao Tome and Principe and Western Sahara, we have 3D seismic requirements of 4,750 square kilometers and 5,000 square kilometers, respectively. Additionally, in Morocco certain geological studies are also required.

The following table presents maturities by expected debt maturity dates, 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

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value. Weighted-average interest rates are based on implied forward rates in the yield curve at the reporting date. This table does not take into account amortization of deferred financing costs.

	Years Ending December 31,						Asset (Liability) Fair Value at June 30,
	2017(5)	2018	2019	2020	2021	Thereafter	2017
	(In thousands, except percentages)						
Fixed rate debt:							
Senior Notes	$ —	$ —	$ —	$ —	$ 525,000	$ —	$ (536,356)
Fixed interest rate	7.88 %	7.88 %	7.88 %	7.88 %	7.88 %	—	
Variable rate debt:							
Facility(1)	$ —	$ —	$ 50,377	$ 404,971	$ 194,652	$ —	$ (650,000)
Weighted average interest rate(2)	4.50 %	5.16 %	5.55 %	6.19 %	6.62 %	—	
Capped interest rate swaps:							
Notional debt amount	$ 200,000	$ 200,000	$ —	$ —	$ —	$ —	$ 628
Cap	3.00 %	3.00 %	—	—	—	—	
Average fixed rate payable(3)	1.23 %	1.23 %	—	—	—	—	
Variable rate receivable(4)	1.27 %	1.54 %	—	—	—	—	

(1) The amounts included in the table represent principal maturities only. The scheduled maturities of debt are based on the level of borrowings and the available borrowing base as of June 30, 2017. Any increases or decreases in the level of borrowings or increases or decreases in the available borrowing base would impact the scheduled maturities of debt during the next five years and thereafter. As of June 30, 2017, there were no borrowings under the Corporate Revolver.

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

(3)

We expect to pay the fixed rate if 1-month LIBOR is below the cap, and pay the market rate less the spread between the cap and the fixed rate if LIBOR is above the cap, net of the capped interest rate swaps.

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

(5) Represents the period July 1, 2017 through December 31, 2017.

Off-Balance Sheet Arrangements

As of June 30, 2017, our material off-balance sheet arrangements and transactions include operating leases and undrawn letters of credit. There are no other transactions, arrangements, or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect Kosmos' liquidity or availability of or requirements for capital resources.

Critical Accounting Policies

We consider accounting policies related to our revenue recognition, exploration and development costs, receivables, income taxes, derivative instruments 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. There have been no changes to our critical accounting policies which are summarized in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" section in our annual report on Form 10-K, for the year ended December 31, 2016, other than as follows:

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Consolidations / Equity Method of Accounting

The Consolidated Financial Statements include the accounts of our wholly-owned subsidiaries. They also include Kosmos' share of the undivided interest in certain assets, liabilities, revenues and expenses. Investments in corporate joint ventures, which we exercise significant influence over, are accounted for using the equity method of accounting.

Equity method investments are integral to our operations. The other parties, who also have an equity interest in these companies, are independent third parties. Kosmos does not invest in these companies in order to remove liabilities from its balance sheet.

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 quarterly report on Form 10-Q and our annual report on Form 10-K, may adversely affect our results as indicated in forward-looking statements. You should read this quarterly report on Form 10-Q, the annual report on Form 10-K 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 and produce from our current discoveries and prospects;
- uncertainties inherent in making estimates of our oil and natural gas data;
- the successful implementation of our and our block partners' prospect discovery and development and drilling plans;
- projected and targeted capital expenditures and other costs, commitments and revenues;
- termination of or intervention in concessions, rights or authorizations granted by the governments of Ghana, Mauritania, Morocco, Sao Tome and Principe, Senegal or Suriname (or their respective national oil companies) or any other federal, state or local governments or authorities, to us;
- our dependence on our key management personnel and our ability to attract and retain qualified technical personnel;
- the ability to obtain financing and to comply with the terms under which such financing may be available;
- the volatility of oil and natural gas prices;
- the availability, cost, function and reliability of developing appropriate infrastructure around and transportation to our discoveries and prospects;

- the availability and cost of drilling rigs, production equipment, supplies, personnel and oilfield services;
- other competitive pressures;
- potential liabilities inherent in oil and natural gas operations, including drilling and production risks and other operational and environmental risks and hazards;
- current and future government regulation of the oil and gas industry or regulation of the investment in or ability to do business with certain countries or regimes;
- cost of compliance with laws and regulations;
- changes in environmental, health and safety or climate change or greenhouse gas (“GHG”) laws and regulations or the implementation, or interpretation, of those laws and regulations;
- adverse effects of sovereign boundary disputes in the jurisdictions in which we operate, including an ongoing maritime boundary demarcation dispute between Cote d’Ivoire and Ghana impacting our operations in the Deepwater Tano Block offshore Ghana;
- environmental liabilities;
- geological, geophysical and other technical and operations, including drilling and oil and gas production and processing;
- military operations, civil unrest, outbreaks of disease, terrorist acts, wars or embargoes;

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- the cost and availability of adequate insurance coverage and whether such coverage is enough to sufficiently mitigate potential losses and whether our insurers comply with their obligations under our coverage agreements;
- our vulnerability to severe weather events;
- our ability to meet our obligations under the agreements governing our indebtedness;
- the availability and cost of financing and refinancing our indebtedness;
- the amount of collateral required to be posted from time to time in our hedging transactions, letters of credit and other secured debt;
- the result of any legal proceedings, arbitrations, or investigations we may be subject to or involved in;
- our success in risk management activities, including the use of derivative financial instruments to hedge commodity and interest rate risks; and
- other risk factors discussed in the "Item 1A. Risk Factors" section of this quarterly report on Form 10-Q and our annual report on Form 10-K.

The words "believe," "may," "will," "aim," "estimate," "continue," "anticipate," "intend," "expect," "plan" and similar words a to identify estimates and forward-looking statements. Estimates and forward-looking statements speak only as of the date they were made, and, except to the extent required by law, we undertake no obligation to update or to review any estimate and/or forward-looking statement because of new information, future events or other factors. Estimates and forward-looking statements involve risks and uncertainties and are not guarantees of future performance. As a result of the risks and uncertainties described above, the estimates and forward-looking statements discussed in this 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. Qualitative and Quantitative Disclosures About Market Risk

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

We manage market and counterparty credit risk in accordance with our policies. In accordance with these policies and guidelines, our management determines the appropriate timing and extent of derivative transactions. See "Item 8. Financial Statements and Supplementary Data — Note 2 — Accounting Policies, Note 8 — Derivative Financial Instruments and Note 9 — Fair Value Measurements" section of our annual report on Form 10-K for a description of the accounting procedures we follow relative to our derivative financial instruments.

The following table reconciles the changes that occurred in fair values of our open derivative contracts during the six months ended June 30, 2017:

	Derivative Contracts Assets (Liabilities)		
	Commodities	Interest Rates	Total
	(In thousands)		
Fair value of contracts outstanding as of December 31, 2016	$ 1,638	$ 53	$ 1,691
Changes in contract fair value	58,708	236	58,944
Contract maturities	(19,756)	339	(19,417)
Fair value of contracts outstanding as of June 30, 2017	$ 40,590	$ 628	$ 41,218

Commodity Price Risk

The Company's revenues, earnings, cash flows, capital investments and, ultimately, future rate of growth are highly dependent on the prices we receive for our crude oil, which have historically been very volatile. Our oil sales are indexed against Dated Brent crude, prices during the six months ended June 30, 2017 ranged between $44.28 and $56.30.

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Commodity Derivative Instruments

We enter into various oil derivative contracts to mitigate our exposure to commodity price risk associated with anticipated future oil production. These contracts currently consist of four-way collars, three-way collars, put options, call options and swaps. In regards to our obligations under our various commodity derivative instruments, if our production does not exceed our existing hedged positions, our exposure to our commodity derivative instruments would increase.

Commodity Price Sensitivity

The following table provides information about our oil derivative financial instruments that were sensitive to changes in oil prices as of June 30, 2017. Volumes and weighted average prices are net of any offsetting derivatives entered into.

			Weighted Average Dated Brent Price per Bbl						Asset (Liability) Fair Value at June 30,
Term	Type of Contract	MBbl	Deferred Premium Payable, Net	Swap	Sold Put	Floor	Ceiling	Call	2017(2)
									(In thousands)
2017:									
July — December	Swap with puts/calls	1,006	$ 2.13	$ 72.50	$ 55.00	$ —	$ —	$ 90.00	$ 14,650
July — December	Swap with puts	1,006	—	64.95	50.00	—	—	—	12,965
July — December	Three-way collars	2,012	1.72	—	30.00	45.00	60.00	—	(1,602)
July — December	Sold calls(1)	1,000	—	—	—	—	85.00	—	—
2018:									
January — December	Three-way collars	2,913	$ 0.74	$ —	$ 41.57	$ 56.57	$ 65.90	$ —	$ 14,026
January — December	Four-way collars	3,000	1.06	—	40.00	50.00	61.33	70.00	3,686
January — December	Sold calls(1)	2,000	—	—	—	—	65.00	—	(2,461)
2019:									

January — December	Sold calls(1)	913	$ —	$ —	$ —	$ —	$ 80.00	$ —	$ (674)

(1) Represents call option contracts sold to counterparties to enhance other derivative positions.

(2) Fair values are based on the average forward Dated Brent oil prices on June 30, 2017 which by year are: 2017 — $48.35, 2018 — $50.53 and 2019 — $52.12. These fair values are subject to changes in the underlying commodity price. The average forward Dated Brent oil prices based on August 1, 2017 market quotes by year are: 2017 — $51.38, 2018 — $52.32 and 2019 — $53.10.

In July 2017, we entered into three-way collar contracts for 3.0 MMBbl from January 2019 through December 2019 with a weighted average floor price of $50.00 per barrel, a weighted average ceiling price of $61.67 per barrel and a weighted average sold put price of $40.00 per barrel. The contracts are indexed to Dated Brent prices.

At June 30, 2017, our open commodity derivative instruments were in a net asset position of $40.6 million. As of June 30, 2017, a hypothetical 10% price increase in the commodity futures price curves would decrease future pre-tax earnings by approximately $26.8 million. Similarly, a hypothetical 10% price decrease would increase future pre-tax earnings by approximately $23.7 million.

Interest Rate Derivative Instruments

See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Contractual Obligations" section of our annual report on Form 10-K for specific information regarding the terms of our interest rate derivative instruments that are sensitive to changes in interest rates.

Interest Rate Sensitivity

At June 30, 2017, we had indebtedness outstanding under the Facility of $650.0 million, of which $450.0 million bore interest at floating rates after consideration of our fixed rate interest rate hedges. The interest rate on this indebtedness as of June 30, 2017 was approximately 4.3%. If LIBOR increased by 10% at this level of floating rate debt, we would pay an additional $0.5 million in interest expense per year on the Facility. We pay commitment fees on the undrawn availability and unavailable commitments under the Facility and on the undrawn availability under the Corporate Revolver, which are not subject to changes in interest rates.

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As of June 30, 2017, the fair market value of our interest rate swaps was a net asset of approximately $0.6 million. If LIBOR changed by 10%, it would have a negligible impact on the fair market value of our interest rate swaps.

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. This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the SEC reports we file or submit under the Exchange Act is accurate, complete and timely. However, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. The design of a control system must reflect the fact that there are resource constraints, and the benefit of controls must be considered relative to their costs. Consequently, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. Based upon this evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of June 30, 2017, in ensuring that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, including that such information is accumulated and communicated to the Company's management, including our Chief Executive Officer and our Chief Financial Officer, to allow timely decisions regarding required disclosure.

Evaluation of Changes in Internal Control over Financial Reporting

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

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

There have been no material changes from the information concerning legal proceedings discussed in the "Item 3. Legal Proceedings" section of our annual report on Form 10-K.

Item 1A. Risk Factors

Other than with respect to the risk factors set forth below, there have been no material changes from the risks discussed in the "Item 1A. Risk Factors" section of our annual report on Form 10-K for the year ended December 31, 2016.

Offshore and deepwater operations involve special risks that could adversely affect results of operations.

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

Deepwater exploration generally involves greater operational and financial risks than exploration in shallower waters. Deepwater drilling generally requires more time and more advanced drilling technologies, involving a higher risk of equipment failure and usually higher drilling costs. In addition, there may be production risks of which we are currently unaware. If we participate in the development of new subsea infrastructure and use floating production systems to transport oil from producing wells, these operations may require substantial time for installation or encounter mechanical difficulties and equipment failures that could result in loss of production, significant liabilities, cost overruns or delays. For example, we have experienced mechanical issues in the Jubilee Field, including failures of its gas and water injection facilities on the FPSO, and are currently working to remediate the turret bearing issue on the FPSO. This resulted in the need to implement new operating and offloading procedures, including the use of tug boats for heading control and a dynamically positioned ("DP") shuttle tanker and storage vessel for offloading. The equipment downtime caused by these mechanical issues negatively impacted oil production during the year.

In addition, Kosmos and its Jubilee partners determined that the risers of the FPSO have experienced increased levels of stress compared to their original design basis, which may cause these risers to suffer operational fatigue earlier than originally anticipated. The Jubilee partnership is currently assessing the condition of the risers and, if required, plans for remediation work of this riser issue which may include instrumentation of the risers to assess further operational fatigue or replacement of all or a part of one or more risers. Such remediation efforts may negatively impact oil production, and/or result in additional expenses.

Furthermore, deepwater operations generally, and operations in Africa and South America, in particular, lack the physical and oilfield service infrastructure present in other regions. As a result, a significant amount of time may elapse between a deepwater discovery and the marketing of the associated oil and natural gas, increasing both the financial and operational risks involved with these operations. Because of the lack and high cost of this infrastructure, further discoveries we may make in Africa and South America may never be economically producible.

In addition, in the event of a well control incident, containment and, potentially, cleanup activities for offshore drilling are costly. The resulting regulatory costs or penalties, and the results of third party lawsuits, as well as associated legal and support expenses, including costs to address negative publicity, could well exceed the actual costs of containment and cleanup. As a result, a well control incident could result in substantial liabilities, and have a significant negative impact on our earnings, cash flows, liquidity, financial position, and stock price.

A maritime boundary demarcation between Cote d’Ivoire and Ghana may affect a portion of our license areas offshore Ghana, including some or all of the TEN fields.

The historical maritime boundary between Ghana and its western neighbor, the Republic of Cote d’Ivoire, forms the western boundary of the DT Block offshore Ghana. In early 2010, Cote d’Ivoire petitioned the United Nations to demarcate the Ivorian territorial maritime boundary with Ghana. In response to the petition, Ghana established a Boundary Commission to undertake negotiations with Cote d'Ivoire in an effort to resolve their respective maritime boundary. The Ivorian Government then issued a map in September 2011, which reflected potential petroleum license areas that overlap with the DT Block. In September 2014, Ghana submitted the matter to arbitration under the United Nations Convention on the Law of the Sea, and in December 2014, the two parties agreed to transfer the dispute to the ITLOS. On January 12, 2015, the ITLOS formed a special chamber to address the maritime boundary dispute.

On March 2, 2015, Cote D'Ivoire applied to the ITLOS for a provisional measures order suspending activities in the disputed area in which the TEN fields is located until the substantive case concerning the border dispute is adjudicated. More specifically, the provisional measures application asked that Ghana be ordered to: (i) suspend all ongoing exploration and exploitation operations in the disputed area, (ii) refrain from granting any authorizations for new exploration and exploitation in the disputed area, (iii) not use any data acquired in the disputed area in any way that would be detrimental to Cote d'Ivoire, and (iv) take any necessary action for the preservation of the continental shelf, its water, and its underground in the disputed area.

In late April 2015, the Special Chamber of ITLOS issued its order in response to Cote d'Ivoire's provisional measures application. In its order, ITLOS rejected Cote d'Ivoire's requests that Ghana suspend its ongoing exploration and development operations in the disputed area but ordered Ghana to: (i) take all necessary steps to ensure that no new drilling either by Ghana or any entity or person under its control takes place in the disputed area; (ii) take all necessary steps to prevent information resulting from past, ongoing or future exploration activities conducted by Ghana, or with its authorization, in the disputed area that is not already in the public domain from being used in any way whatsoever to the detriment of Cote d'Ivoire; (iii) carry out strict and continuous monitoring of all activities undertaken by Ghana or with its authorization in the disputed area with a view to ensuring the prevention of serious harm to the marine environment; (iv) take all necessary steps to prevent serious harm to the marine environment, including the continental shelf and its superjacent waters, in the disputed area and shall cooperate to that end; and (v) pursue cooperation with Cote d'Ivoire and refrain from any unilateral action that might lead to aggravating the dispute. On June 11, 2015, the Ghana Attorney General issued a letter to the DT Operator, which confirmed the DT Block partners may (i) continue to drill wells that had been started but not completed prior to the ITLOS order and (ii) carry out completion work on wells that have already been drilled. The TEN fields achieved first oil in the third quarter of 2016. With respect to the Wawa Discovery, in April 2016 the Ghana Ministry of Energy approved our request to enlarge the TEN fields and production area subject to continued subsurface and development concept evaluation, along with the requirement to integrate the Wawa Discovery into the TEN PoD. Any future drilling activities for the Wawa Discovery would be subject to resolution of the ITLOS order.

We do not know if the maritime boundary dispute will change our and our block partners' rights to undertake further development of and production from our discoveries within such areas. If Cote d'Ivoire is successful in the ITLOS proceeding, we may lose rights to certain acreage governed by our petroleum contracts for the DT block, which may potentially include some or all of the TEN fields. Thus, in the event that the ITLOS proceedings result in an unfavorable outcome for Ghana, our operations, production and reserves within such areas could be materially impacted. However, the Company could have contractual recourse against Ghana under the Company's concession agreements if this were to occur, which could limit the effect on the Company's and/or the DT Block partners' financial position or profitability.

We may not be able to commercialize our interests in any natural gas produced from our license areas.

The development of the market for natural gas in our license areas is in its early stages. Currently the infrastructure to transport and process natural gas on commercial terms is limited and the expenses associated with constructing such infrastructure ourselves may not be commercially viable given local prices currently paid for natural gas. Accordingly, there may be limited or no value derived from any natural gas produced from our license areas.

In Ghana, we currently produce associated gas from the Jubilee and TEN fields. A gas pipeline from the Jubilee Field has been constructed to transport such natural gas for processing and sale. However, we granted the first 200 Bcf of natural gas exported from the Jubilee Field to Ghana at zero cost. Through June 30, 2017, the Jubilee partners have provided approximately 58 Bcf of natural gas from the Jubilee Field to Ghana. Thus, in Ghana, it is forecasted to be a few years before we are able to commercialize the Jubilee Field natural gas. As a result, we do not currently book proved gas reserves associated with natural gas sales from the Jubilee Field in Ghana. However, upon finalization and execution of a gas sales agreement for such Jubilee Field natural gas that will have a price associated with it, we will book the associated gas reserves. A gas pipeline from the TEN fields to the Jubilee Field was completed in the first quarter of 2017 to transport associated natural gas as well as non-associated natural gas for processing and sale. However, we are still finalizing gas

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sales agreements for such gas, and as a result, we do not currenly book proved gas reserves associated with future natural gas sales from the TEN fields in Ghana.

In Mauritania and Senegal, we plan to export the majority of our gas resource to the liquefied natural gas ("LNG") market. However, that plan is contingent on making a final investment decision on our gas discoveries and constructing the necessary infrastructure to produce, liquefy and transport the gas to the market as well as finding an LNG purchaser. Additionally, such plans are also contingent upon receipt of required government approvals, including prior approval by the Governments of both Senegal and Mauritania of the Intergovernmental Cooperation Agreement ("ICA") which underpins fundamental commercial and legal assurances that are necessary to proceed with the cross-border unitization of the Greater Tortue Area. There is no certainty concerning if or when the ICA will be concluded.

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

Issuer Purchases of Equity Securities

Under the terms of our Long Term Incentive Plan ("LTIP"), we have issued restricted shares to our employees. On the date that these restricted shares vest, we provide such employees the option to sell shares to cover their tax liability, via a net exercise provision pursuant to our applicable restricted share award agreements and the LTIP, either the number of vested shares (based on the closing price of our common shares on such vesting date) equal to the minimum statutorily tax liability owed by such grantee or up to the maximum statutory tax liability for such grantee. The Company may repurchase the restricted shares sold by the grantees to settle their tax liability. The repurchased shares are reallocated to the number of shares available for issuance under the LTIP. The following table outlines the total number of restricted shares purchased during the six months ended, June 30, 2017 and the average price paid per share.

	Total Number of Shares Purchased (In thousands)	Average Price Paid per Share
January 1, 2017—January 31, 2017	74	$ 7.01
February 1, 2017—February 28, 2017	—	—
March 1, 2017—March 31, 2017	—	—
April 1, 2017—April 30, 2017	—	—
May 1, 2017—May 31, 2017	—	—
June 1, 2017—June 30, 2017	13	6.12
Total	87	6.87

Item 3.Defaults Upon Senior Securities

None.

Item 4.Mine Safety Disclosures

Not applicable.

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 annual report on Form 10-K, other than as follows:

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

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

We are not presently aware that we and our consolidated subsidiaries have knowingly engaged in any transaction or dealing reportable under Section 13(r) of the Exchange Act during the fiscal quarter ended June 30, 2017. In addition,

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except as described below, at the time of filing this quarterly report on Form 10-Q, we are not aware of any such reportable transactions or dealings by companies that may be considered our affiliates as to whether they have knowingly engaged in any such reportable transactions or dealings during such period. Upon the filing of periodic reports by such other companies for the fiscal quarter or fiscal year ended June 30, 2017, as the case may be, additional reportable transactions may be disclosed by such companies.

As of June 30, 2017, funds affiliated with Warburg Pincus (“Warburg Pincus”) held approximately 24% of our outstanding common shares. We are also a party to a shareholders agreement with Warburg Pincus pursuant to which, among other things, Warburg Pincus currently has the right to designate two members of our board of directors. Accordingly, Warburg Pincus may be deemed an “affiliate” of us, both currently and during the fiscal quarter ended June 30, 2017.

Disclosure relating to Warburg Pincus and its affiliates

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

SAMIH Disclosure:

Quarter ended March 31, 2017

Santander UK plc (“Santander UK”) holds two savings accounts and one current account for two customers resident in the United Kingdom (“UK”) who are currently designated by the United States (“US”) under the Specially Designated Global Terrorist (“SDGT”) sanctions program. Revenues and profits generated by Santander UK on these accounts in the first half of calendar year 2017 were negligible relative to the overall revenues and profits of Banco Santander SA.

Santander UK holds two frozen current accounts for two UK nationals who are designated by the US under the SDGT sanctions program. The accounts held by each customer have been frozen since their designation and have remained frozen through the first half of calendar year 2017. The accounts are in arrears (£1,844.73 in debit combined) and are currently being managed by Santander UK Collections & Recoveries department. No revenues or profits were generated by Santander UK on this account in the first half of calendar year 2017.

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 Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

	Kosmos Energy Ltd. (Registrant)
Date August 7, 2017	/s/ THOMAS P. CHAMBERS Thomas P. Chambers Senior Vice President and Chief Financial Officer (Principal Financial Officer)

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INDEX OF EXHIBITS

Exhibit Number	Description of Document
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.