Form

Unknown document format

D> 2,090

Total operating revenues

306,509 305,007 908,802 710,204

Operating expenses:

Production:

Lease operating

28,094 37,539 95,700 94,676

Workover and other

5,773 2,029 12,550 4,276

Taxes other than income

28,532 26,613 83,002 62,616

Gathering and other

7,460 3,766 18,119 6,901

Restructuring

987 507

General and administrative

29,569 33,762 90,110 98,885

Depletion, depreciation and accretion

135,578 143,091 388,956 320,264

Full cost ceiling impairment

909,098 61,165 909,098

Other operating property and equipment impairment

67,254 3,789 67,254

Goodwill impairment

228,875 228,875

Total operating expenses

235,006 1,452,027 754,378 1,793,352

Income (loss) from operations

71,503 (1,147,020) 154,424 (1,083,148)

Other income (expenses):

Net gain (loss) on derivative contracts

163,287 (54,427) 8,589 (38,749)

Interest expense and other, net

(38,450) (13,663) (107,114) (24,245)

Total other income (expenses)

124,837 (68,090) (98,525) (62,994)

Income (loss) before income taxes

196,340 (1,215,110) 55,899 (1,146,142)

Income tax benefit (provision)

1,295 360,283 1,295 333,868

Net income (loss)

197,635 (854,827) 57,194 (812,274)

Series A preferred dividends

(4,959) (5,070) (14,878) (5,786)

Preferred dividends on redeemable noncontrolling interest

(5,823) (6,719)

Net income (loss) available to common stockholders

$186,853 $(859,897) $35,597 $(818,060)

Net income (loss) per share of common stock:

Basic

$0.45	$(2.19)	$0.09	$(2.22)

Diluted

$0.36	$(2.19)	$0.08	$(2.22)

Weighted average common shares outstanding:

Basic

416,470	392,726	415,264	368,696

Diluted

548,246	392,726	423,033	368,696

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

Table of Contents

HALCÓN RESOURCES CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited)

(In thousands, except share and per share amounts)

	September 30, 2014	December 31, 2013
Current assets:		
Cash	$ 94,688	$ 2,834
Accounts receivable	281,582	312,518
Receivables from derivative contracts	19,715	2,028
Restricted cash	15,984	
Inventory	6,110	5,148
Prepaids and other	14,870	16,098
Total current assets	432,949	338,626
Oil and natural gas properties (full cost method):		
Evaluated	5,630,830	4,960,467
Unevaluated	2,259,099	2,028,044
Gross oil and natural gas properties	7,889,929	6,988,511
Less accumulated depletion	(2,631,832)	(2,189,515)
Net oil and natural gas properties	5,258,097	4,798,996
Other operating property and equipment:		
Gas gathering and other operating assets	157,703	125,837
Less accumulated depreciation	(13,898)	(8,461)
Net other operating property and equipment	143,805	117,376
Other noncurrent assets:		
Receivables from derivative contracts	24,144	22,734
Debt issuance costs, net	58,037	64,308
Deferred income taxes	11,683	8,474
Equity in oil and natural gas partnership	4,472	4,463
Funds in escrow and other	1,225	1,514
Total assets	$ 5,934,412	$ 5,356,491

Current liabilities:		
Accounts payable and accrued liabilities	$ 698,070	$ 636,589

Liabilities from derivative contracts	1,208	17,859
Asset retirement obligations	218	71
Current portion of deferred income taxes	11,683	8,474
Current portion of long-term debt	694	1,389
Total current liabilities	711,873	664,382
Long-term debt	3,533,158	3,183,823
Other noncurrent liabilities:		
Liabilities from derivative contracts	17,629	19,333
Asset retirement obligations	35,677	39,186
Other	7,501	2,157
Commitments and contingencies (Note 8)		
Mezzanine equity:		
Redeemable noncontrolling interest	110,708	
Stockholders' equity:		
Preferred stock: 1,000,000 shares of $0.0001 par value authorized; 345,000 shares of 5.75% Cumulative Perpetual Convertible Series A, issued and outstanding as of September 30, 2014 and December 31, 2013		
Common stock: 1,340,000,000 and 670,000,000 shares of $0.0001 par value authorized; 422,467,166 and 415,729,962 shares issued and outstanding at September 30, 2014 and December 31, 2013, respectively	41	41
Additional paid-in capital	2,988,445	2,953,786
Accumulated deficit	(1,470,620)	(1,506,217)
Total stockholders' equity	1,517,866	1,447,610
Total liabilities and stockholders' equity	$ 5,934,412	$ 5,356,491

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

Table of Contents

HALCÓN RESOURCES CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (Unaudited)

(In thousands)

	Preferred Stock		Common Stock		Additional Paid-In	Treasury Stock		Accumulated	Stockholders'
	Shares	Amount	Shares	Amount	Capital	Shares	Amount	Deficit	Equity
Balances at December 31, 2012		$	259,802	$ 26	$ 1,681,717	1,650	$ (9,298)	$ (274,463)	$ 1,397,982
Net income (loss)								(1,222,662)	(1,222,662)
Dividends on Series A preferred stock			2,045		9,092			(9,092)	
Preferred stock conversion			108,801	11	695,227				695,238
Sale of Series A preferred stock	345				345,000				345,000
Common stock issuance			43,700	4	222,866				222,870
Offering costs					(17,346)				(17,346)
Long-term incentive plan grants			3,267						
Long-term incentive plan forfeitures			(205)						
Reduction in shares to cover individuals' tax withholding			(30)		(148)				(148)
Retirement of shares in treasury			(442)		(2,492)	(442)	2,492		
Long-term incentive plan grants issued out of treasury			(1,208)		(6,806)	(1,208)	6,806		
Share-based compensation					26,676				26,676
Balances at December 31, 2013	345	$	415,730	$ 41	$ 2,953,786		$	$ (1,506,217)	$ 1,447,610
Net income (loss)								57,194	57,194
Dividends on Series A preferred stock			3,262		14,878			(14,878)	
Dividends on redeemable noncontrolling interest								(6,719)	(6,719)
Offering costs					39				39
Long-term incentive plan grants			3,916						
Long-term incentive plan forfeitures			(328)						
Reduction in shares to cover individuals' tax withholding			(113)		(444)				(444)
Share-based compensation					20,186				20,186
Balances at September 30, 2014	345	$	422,467	$ 41	$ 2,988,445		$	$ (1,470,620)	$ 1,517,866

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

Table of Contents

HALCÓN RESOURCES CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)

(In thousands)

	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Cash flows from operating activities:		
Net income (loss)	$ 57,194	$ (812,274)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depletion, depreciation and accretion	388,956	320,264
Full cost ceiling impairment	61,165	909,098
Other operating property and equipment impairment	3,789	67,254
Goodwill impairment		228,875
Deferred income tax provision (benefit)		(334,881)
Share-based compensation, net	13,837	11,994
Unrealized loss (gain) on derivative contracts	(38,660)	18,956
Amortization and write-off of deferred loan costs	3,198	1,343
Non-cash interest and amortization of discount and premium	1,976	1,395
Other income (expense)	(594)	(5,241)
Change in assets and liabilities, net of acquisitions:		
Accounts receivable	31,020	(83,001)
Inventory	(962)	(557)
Prepaids and other	1,742	(8,441)
Accounts payable and accrued liabilities	59,229	76,821
Net cash provided by (used in) operating activities	581,890	391,605
Cash flows from investing activities:		
Oil and natural gas capital expenditures	(1,178,649)	(1,828,969)
Acquisition of Williston Basin Assets		(32,181)
Proceeds received from sale of oil and natural gas assets	479,974	160,268
Advance on carried interest	(189,442)	
Other operating property and equipment capital expenditures	(40,356)	(120,071)
Funds held in escrow and other	1,221	(5,547)
Net cash provided by (used in) investing activities	(927,252)	(1,826,500)
Cash flows from financing activities:		
Proceeds from borrowings	1,744,000	2,760,000
Repayments of borrowings	(1,399,000)	(1,858,400)
Debt issuance costs	(757)	(19,302)
Series A preferred stock issuance		345,000
Common stock issued		222,870
HK TMS, LLC preferred stock issued	110,051	
HK TMS, LLC tranche rights	4,516	
Preferred dividends on redeemable noncontrolling interest	(3,518)	
Restricted cash	(15,984)	
Offering costs and other	(2,092)	(17,318)

Net cash provided by (used in) financing activities	437,216	1,432,850
Net increase (decrease) in cash	91,854	(2,045)
Cash at beginning of period	2,834	2,506
Cash at end of period	$ 94,688	$ 461
Disclosure of non-cash investing and financing activities:		
Accrued capitalized interest	$ (5,340)	$ 10,549
Asset retirement obligations	(3,396)	10,077
Series A preferred dividends paid in common stock	14,878	4,133
Deemed dividends on redeemable noncontrolling interest	3,201	

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. FINANCIAL STATEMENT PRESENTATION

Basis of Presentation and Principles of Consolidation

Halcón Resources Corporation (Halcón or the Company) is an independent energy company focused on the acquisition, production, exploration and development of onshore liquids-rich assets in the United States. The unaudited condensed consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries and an equity method investment. The Company operates in one segment which focuses on oil and natural gas acquisition, production, exploration and development. The Company's oil and natural gas properties are managed as a whole rather than through discrete operating areas. Operational information is tracked by operating area; however, financial performance is assessed as a whole. Allocation of capital is made across the Company's entire portfolio without regard to operating area. All intercompany accounts and transactions have been eliminated. These unaudited condensed consolidated financial statements reflect, in the opinion of the Company's management, all adjustments, consisting of normal and recurring adjustments, necessary to present fairly the financial position as of, and the results of operations for, the periods presented. During interim periods, Halcón follows the accounting policies disclosed in its 2013 Annual Report on Form 10-K, as filed with the United States Securities and Exchange Commission (SEC). Please refer to the notes in the 2013 Annual Report on Form 10-K when reviewing interim financial results.

Use of Estimates

The preparation of the Company's unaudited condensed consolidated financial statements in conformity with accounting principles generally accepted in the United States requires the Company's management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the unaudited condensed consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Estimates and assumptions that, in the opinion of management of the Company, are significant include oil and natural gas revenue, capital and operating expense accruals, oil and natural gas reserves, depletion relating to oil and natural gas properties, asset retirement obligations, fair value estimates and income taxes. The Company bases its estimates and judgments on historical experience and on various other assumptions and information that are believed to be reasonable under the circumstances. Estimates and assumptions about future events and their effects cannot be perceived with certainty and, accordingly, these estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as the Company's operating environment changes. Actual results may differ from the estimates and assumptions used in the preparation of the Company's unaudited condensed consolidated financial statements.

Interim period results are not necessarily indicative of results of operations or cash flows for the full year and accordingly, certain information normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States, has been condensed or omitted. The Company has evaluated events or transactions through the date of issuance of these unaudited condensed consolidated financial statements.

Accounts Receivable and Allowance for Doubtful Accounts

The Company's accounts receivable are primarily receivables from joint interest owners and oil and natural gas purchasers. Accounts receivable are recorded at the amount due, less an allowance for doubtful accounts, when applicable. The Company establishes provisions for losses on accounts

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. FINANCIAL STATEMENT PRESENTATION (Continued)

receivable if it determines that collection of all or part of the outstanding balance is doubtful. The Company regularly reviews collectability and establishes or adjusts the allowance for doubtful accounts as necessary using the specific identification method. There were no material allowances for doubtful accounts as of September 30, 2014 or December 31, 2013.

Other Operating Property and Equipment

Gas gathering systems and equipment are recorded at cost. Depreciation is calculated using the straight-line method over a 30-year estimated useful life. Upon disposition, the cost and accumulated depreciation are removed and any gains or losses are reflected in current operations. Maintenance and repair costs are charged to operating expense as incurred. Material expenditures which increase the life or productive capacity of an asset are capitalized and depreciated over the estimated remaining useful life of the asset. The Company capitalized $115.3 million and $92.0 million as of September 30, 2014 and December 31, 2013, respectively, related to the construction of its gas gathering systems.

Other operating assets are recorded at cost. Depreciation is calculated using the straight-line method over the following estimated useful lives: automobiles and computers, three years; computer software, fixtures, furniture and equipment, five years; trailers, seven years; heavy equipment, ten years; an airplane and buildings, twenty years and leasehold improvements, lease term. Upon disposition, the cost and accumulated depreciation are removed and any gains or losses are reflected in current operations. Maintenance and repair costs are charged to operating expense as incurred. Material expenditures which increase the life of an asset are capitalized and depreciated over the estimated remaining useful life of the asset.

The Company reviews its gas gathering systems and equipment and other operating assets for impairment in accordance with ASC 360, *Property, Plant, and Equipment* (ASC 360). ASC 360 requires the Company to evaluate gas gathering systems and equipment and other operating assets for impairment as events occur or circumstances change that would more likely than not reduce the fair value below the carrying amount. If the carrying amount is not recoverable from its undiscounted cash flows, then the Company would recognize an impairment loss for the difference between the carrying amount and the current fair value. Further, the Company evaluates the remaining useful lives of its gas gathering systems and other operating assets at each reporting period to determine whether events and circumstances warrant a revision to the remaining depreciation periods. For the three months ended September 30, 2013, the Company recorded a non-cash impairment charge of $67.3 million in *"Other operating property and equipment impairment"* in the Company's unaudited condensed consolidated statements of operations and in *"Gas gathering and other operating assets"* in the Company's unaudited condensed consolidated balance sheets. The impairment relates to the Company's gross investments of $68.3 million in gas gathering infrastructure that will not be economically recoverable due to the Company's shift in exploration, drilling and developmental plans from the Woodbine to El Halcón during the third quarter of 2013. Operating results for the nine months ended September 30, 2014 reflect the impact of approximately $3.8 million in charges related to the disposition of midstream infrastructure assets associated with certain non-core property divestitures. These charges are included in *"Other operating property and equipment impairment"* in the Company's unaudited condensed consolidated statements of operations.

In accordance with ASC 820, *Fair Value Measurements and Disclosures* (ASC 820), a financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. FINANCIAL STATEMENT PRESENTATION (Continued)

to the fair value measurement. The estimate of the fair value of the Company's gas gathering systems was based on an income approach that estimated future cash flows associated with those assets, which resulted in negative net cash flows due to insufficient throughput of natural gas volumes and certain fixed costs necessary to operate and maintain the assets. This estimation includes the use of unobservable inputs, such as estimated future production, and gathering and compression revenues and operating expenses. The use of these unobservable inputs results in the fair value estimate of the Company's gas gathering systems being classified as Level 3.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of liabilities assumed in an acquisition. ASC 350, *Intangibles Goodwill and Other* (ASC 350) requires that intangible assets with indefinite lives, including goodwill, be evaluated on an annual basis for impairment or more frequently if events occur or circumstances change that could potentially result in impairment. The goodwill impairment test requires the allocation of goodwill and all other assets and liabilities to reporting units. However, the Company has only one reporting unit. The Company performs its goodwill impairment test annually, using a measurement date of July 1, or more often if circumstances require. The Company carried goodwill as of December 31, 2012 related to its acquisition of GeoResources, Inc.

The Company performed its annual goodwill impairment test during the third quarter of 2013, and based on this review, the Company recorded a non-cash impairment charge of $228.9 million to reduce the carrying value of goodwill to zero. The Company has recorded the goodwill impairment in *"Goodwill impairment"* in the Company's unaudited condensed consolidated statements of operations. In the first step of the goodwill impairment test, the Company determined that the fair value of its reporting unit was less than the carrying amount, including goodwill, primarily due to pricing deterioration in the NYMEX forward pricing curve coupled with less favorable oil price differentials in the Company's core areas, both factors which adversely impacted the fair value of the Company's proved reserves. Therefore, the Company performed the second step of the goodwill impairment test, which led the Company to conclude that there would be no remaining implied fair value attributable to goodwill.

In estimating the fair value of its reporting unit, the Company used a combination of the income and market approaches. For purposes of estimating the fair value of the Company's oil and natural gas proved reserves, an income approach was used which estimated fair value based on the anticipated cash flows associated with the Company's proved reserves, discounted using a weighted average cost of capital rate. In estimating the fair value of the Company's unproved acreage, a market approach was used in which a review of recent transactions involving properties in the same geographical location indicated the fair value of the Company's unproved acreage from a market participant perspective.

The estimation of the fair value of the Company's reporting unit includes the use of unobservable inputs, such as estimates of proved reserves, unproved acreage values, the weighted average cost of capital (discount rate), future pricing beyond a certain period and estimated future capital and operating costs. The use of these unobservable inputs results in the fair value estimate being classified as Level 3. Although the Company believes the assumptions and estimates used in the fair value calculation of its reporting unit are reasonable and appropriate, different assumptions and estimates could materially impact the analysis and resulting conclusions. The assumptions used in estimating the

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. FINANCIAL STATEMENT PRESENTATION (Continued)

fair value of the reporting unit and performing the goodwill impairment test are inherently uncertain and require management judgment.

Recently Issued Accounting Pronouncements

In February 2013, the FASB issued ASU No. 2013-04, *Obligations Resulting from Joint and Several Liability Arrangements for which the Total Amount of the Obligation is Fixed at the Reporting Date* (ASU 2013-04). ASU 2013-04 provides guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements, such as debt arrangements, other contractual obligations and settled litigation and judicial rulings. This pronouncement must be applied retrospectively and is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The adoption of ASU 2013-04 did not have an impact to the Company's operating results, financial position and disclosures.

In February 2013, the FASB issued ASU No. 2013-11, *Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists* (ASU 2013-11). ASU 2013-11 provides explicit guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. This pronouncement should be applied prospectively to all unrecognized tax benefits that exist at the effective date and retrospective application is permitted. ASU 2013-11 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The adoption of this pronouncement did not have an impact to the Company's operating results and financial position.

In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers* (ASU 2014-09). ASU 2014-09 states that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The standard provides five steps an entity should apply in determining its revenue recognition. ASU 2014-09 must be applied retrospectively and is effective for annual reporting periods, and interim periods with that reporting period, beginning after December 15, 2016. Early adoption is not permitted. The Company is currently assessing the impact of the adoption of ASU 2014-09 on the Company's operating results, financial position and disclosures.

In August 2014, the FASB issued ASU No. 2014-15, *Presentation of Financial Statements Going Concern* (ASU 2014-15). ASU 2014-15 is effective for annual reporting periods (including interim periods within those periods) ending after December 15, 2016. Early application is permitted. The amendments in ASU 2014-15 create a new ASC Sub-topic 205-40, *Presentation of Financial Statements Going Concern* and require management to assess for each annual and interim reporting period if conditions exist that raise substantial doubt about an entity's ability to continue as a going concern. The rule requires various disclosures depending on the facts and circumstances surrounding an entity's ability to continue as a going concern. The Company is in the process of assessing the effects of the application of the new guidance.

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. ACQUISITIONS AND DIVESTITURES

Divestitures

East Texas Assets

On May 9, 2014, the Company completed the divestiture of certain non-core assets in East Texas (the East Texas Assets) to a privately-owned company for a total purchase price of $426.3 million after closing adjustments for (i) operating expenses, capital expenditures and revenues between the effective date and the closing date, (ii) title and environmental defects, and (iii) other purchase price adjustments customary in oil and gas purchase and sale agreements. The effective date of the transaction was April 1, 2014. Proceeds from the sale were recorded as a reduction to the carrying value of the Company's full cost pool with no gain or loss recorded.

Non-core Properties

During the third quarter of 2013, the Company entered into three separate purchase and sale agreements with unrelated parties to divest parcels of non-core properties located in the United States for total consideration, after post-closing adjustments, of approximately $276.6 million. All three of the divestitures were closed by December 31, 2013. The effective date of the transactions was July 1, 2013. Proceeds from the sales were recorded as a reduction to the carrying value of the Company's full cost pool with no gain or loss recorded.

Eagle Ford Assets

On July 19, 2013, the Company completed the sale of its interest in Eagle Ford assets located in Fayette and Gonzales Counties, Texas, previously acquired as part of the merger with GeoResources, Inc. (the Merger), to private buyers for proceeds of approximately $148.6 million, after post-closing adjustments. The transaction had an effective date of January 1, 2013. Proceeds from the sale were recorded as a reduction to the carrying value of the Company's full cost pool with no gain or loss recorded.

3. OIL AND NATURAL GAS PROPERTIES

The Company uses the full cost method of accounting for its investment in oil and natural gas properties. Under this method of accounting, all costs of acquisition, exploration and development of oil and natural gas reserves (including such costs as leasehold acquisition costs, geological expenditures, dry hole costs, tangible and intangible development costs and direct internal costs) are capitalized as the cost of oil and natural gas properties when incurred. To the extent capitalized costs of evaluated oil and natural gas properties, net of accumulated depletion, exceed the discounted future net revenues of proved oil and natural gas reserves, net of deferred taxes, such excess capitalized costs are charged to expense.

The Company assesses all properties classified as unevaluated property on a quarterly basis for possible impairment or reduction in value. The Company assesses properties on an individual basis or as a group, if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. OIL AND NATURAL GAS PROPERTIES (Continued)

associated leasehold costs are transferred to the full cost pool and are then subject to depletion and the full cost ceiling test limitation.

Investments in unevaluated oil and natural gas properties and exploration and development projects for which depletion expense is not currently recognized, and for which exploration or development activities are in progress, qualify for interest capitalization. The capitalized interest is determined by multiplying the Company's weighted-average borrowing cost on debt by the average amount of qualifying costs incurred that are excluded from the full cost pool; however, the amount of capitalized interest cannot exceed the amount of gross interest expense incurred in any given period. The capitalized interest amounts are recorded as additions to unevaluated oil and natural gas properties on the unaudited condensed consolidated balance sheets. As the costs excluded are transferred to the full cost pool, the associated capitalized interest is also transferred to the full cost pool. For the nine months ended September 30, 2014 and 2013, the Company capitalized interest costs of $128.9 million and $157.6 million, respectively.

At September 30, 2014, the ceiling test value of the Company's reserves was calculated based on the first-day-of-the-month average for the 12-months ended September 30, 2014 of the West Texas Intermediate (WTI) spot price of $99.08 per barrel, adjusted by lease or field for quality, transportation fees, and regional price differentials, and the first-day-of-the-month average for the 12-months ended September 30, 2014 of the Henry Hub price of $4.24 per million British thermal units (MMBtu), adjusted by lease or field for energy content, transportation fees, and regional price differentials. The Company's net book value of oil and natural gas properties at September 30, 2014 did not exceed the ceiling amount. At March 31, 2014, the Company recorded a full cost ceiling test impairment before income taxes of $61.2 million ($39.0 million after taxes).

At September 30, 2013 the ceiling test value of the Company's reserves was calculated based on the first-day-of-the-month average of the 12-months ended September 30, 2013 of the WTI spot price of $95.20 per barrel, adjusted by lease or field for quality, transportation fees, and regional price differentials, and the first-day-of-the-month average of the 12-months ended September 30, 2013 of the Henry Hub price of $3.61 per MMbtu, adjusted by lease or field for energy content, transportation fees, and regional price differentials. Using these prices, the Company's net book value of oil and natural gas properties at September 30, 2013 exceeded the ceiling amount. As a result, the Company recorded a full cost ceiling test impairment before income taxes of $909.1 million ($574.8 million after taxes). The combined impact of less favorable oil price differentials adversely affecting proved reserve values and the transfer of approximately $655.7 million of unevaluated Woodbine and Utica properties to the full cost pool contributed to the ceiling impairment.

The Company recorded the full cost ceiling test impairments in *"Full cost ceiling impairment"* in the Company's unaudited condensed consolidated statements of operations and in *"Accumulated depletion"* in the Company's unaudited condensed consolidated balance sheets. Changes in production rates, levels of reserves, future development costs, transfers of unevaluated properties, commodity prices, and other factors will determine the Company's ceiling test calculations and impairment analyses in future periods.

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. LONG-TERM DEBT

Long-term debt as of September 30, 2014 and December 31, 2013 consisted of the following:

	September 30, 2014(1)	December 31, 2013(1)
	(In thousands)	
Senior revolving credit facility	$ 345,000	$
9.25% senior notes due 2022	400,000	400,000
8.875% senior notes due 2021(2)	1,370,630	1,372,355
9.75% senior notes due 2020(3)	1,151,891	1,152,099
8.0% convertible note due 2017(4)	265,637	259,369
	$ 3,533,158	$ 3,183,823

(1) *Table excludes $0.7 million and $1.4 million of deferred premiums on derivative contracts which were classified as current at September 30, 2014 and December 31, 2013, respectively.*

(2) *Amounts are net of a $4.7 million and a $5.1 million unamortized discount at September 30, 2014 and December 31, 2013, respectively, related to the issuance of the original 2021 Notes. The unamortized premium related to the additional 2021 Notes was approximately $25.4 million and $27.5 million at September 30, 2014 and December 31, 2013, respectively. See "8.875% Senior Notes" below for more details.*

(3) *Amounts are net of an $8.1 million and an $8.9 million unamortized discount at September 30, 2014 and December 31, 2013, respectively, related to the issuance of the original 2020 Notes. The unamortized premium related to the additional 2020 Notes was approximately $10.0 million and $11.0 million at September 30, 2014 and December 31, 2013, respectively. See "9.75% Senior Notes" below for more details.*

(4) *Amount is net of a $24.0 million and a $30.3 million unamortized discount at September 30, 2014 and December 31, 2013, respectively. See "8.0% Convertible Note" below for more details.*

Senior Revolving Credit Facility

On February 8, 2012, the Company entered into a senior secured revolving credit agreement (the Senior Credit Agreement) with JPMorgan Chase Bank, N.A., as administrative agent, and the other lenders party thereto. The Senior Credit Agreement provides for a $1.5 billion facility with a current borrowing base of $1.05 billion. Amounts borrowed under the Senior Credit Agreement will mature on February 8, 2017. The borrowing base will be redetermined semi-annually, with the lenders and the Company each having the right to one interim unscheduled redetermination between any two consecutive semi-annual redeterminations. The borrowing base takes into account the Company's oil and natural gas properties, proved reserves, total indebtedness, and other relevant factors consistent with customary oil and natural gas lending criteria. The borrowing base is subject to a reduction equal to the product of 0.25 multiplied by the stated principal amount (without regard to any initial issue discount) of any future notes or other long-term debt securities that the Company may issue. Funds advanced under the Senior Credit Agreement may be paid down and re-borrowed during the five-year term of the facility. Amounts outstanding under the Senior Credit Agreement bear interest at specified margins over the base rate of 0.50% to 1.50% for ABR-based loans or at specified margins over

15

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. LONG-TERM DEBT (Continued)

LIBOR of 1.50% to 2.50% for Eurodollar-based loans. These margins fluctuate based on the Company's utilization of the facility. Advances under the Senior Credit Agreement are secured by liens on substantially all of the Company's and its restricted subsidiaries' properties and assets. The Senior Credit Agreement contains customary representations, warranties and covenants including, among others, restrictions on the payment of dividends on the Company's capital stock and financial covenants, including minimum working capital levels (the ratio of current assets plus the unused commitment under the Senior Credit Agreement to current liabilities) of not less than 1.0 to 1.0 and minimum coverage of interest expenses of i) not less than 2.0 to 1.0 through December 31, 2014 (pursuant to the Seventh Amendment, discussed below) and ii) not less than 2.5 to 1.0 for subsequent periods.

At September 30, 2014, the Company had $345.0 million of indebtedness outstanding, $1.1 million of letters of credit outstanding and approximately $703.9 million of borrowing capacity available under the Company's Senior Credit Agreement.

On September 30, 2014, the Company entered into the Eighth Amendment to its Senior Credit Agreement (the Eighth Amendment). The Eighth Amendment increased the borrowing base under its Senior Credit Agreement from $700.0 million to $1.05 billion. On March 21, 2014, the Company entered into the Seventh Amendment to its Senior Credit Agreement (the Seventh Amendment). The Seventh Amendment provided the Company additional flexibility under the interest coverage test by modifying the minimum Interest Coverage Ratio to be 2.0 to 1.0 for any fiscal quarter ending on or before December 31, 2014.

At September 30, 2014, the Company was in compliance with the financial covenants under the Senior Credit Agreement.

9.25% Senior Notes

On August 13, 2013, the Company issued at par $400.0 million aggregate principal amount of 9.25% senior notes due 2022 (the 2022 Notes). The net proceeds from the offering of approximately $392.1 million (after deducting commissions and offering expenses) were used to repay a portion of the then outstanding borrowings under the Company's Senior Credit Agreement.

The 2022 Notes bear interest at a rate of 9.25% per annum, payable semi- annually on February 15 and August 15 of each year, beginning on February 15, 2014. The 2022 Notes will mature on February 15, 2022. The 2022 Notes are senior unsecured obligations of the Company, rank equally with all of its current and future senior indebtedness and are jointly and severally, fully and unconditionally guaranteed on a senior unsecured basis by the Company's existing 100% owned subsidiaries, except for one subsidiary, HK TMS, LLC. Halcón, the issuer of the 2022 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

On May 23, 2014, the Company completed a registered exchange offer of the outstanding 2022 Notes for new registered notes having terms substantially identical to the 2022 Notes.

On or before August 15, 2016, the Company may redeem up to 35% of the aggregate principal amount of the 2022 Notes with the net cash proceeds of certain equity offerings at a redemption price of 109.25% of the principal amount plus accrued and unpaid interest to the redemption date provided that: at least 65% in aggregate principal amount of the 2022 Notes originally issued remains outstanding immediately after the redemption and the redemption occurs within 180 days of the related

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. LONG-TERM DEBT (Continued)

equity offering. In addition, at any time prior to August 15, 2017, the Company may redeem some or all of the 2022 Notes for the principal amount thereof, plus accrued and unpaid interest plus a make whole premium equal to the excess, if any of (a) the present value at such time of (i) the redemption price of such note at August 15, 2017, plus (ii) any required interest payments due on the notes through August 15, 2017 (excluding currently accrued and unpaid interest) computed using a discount rate equal to the Treasury Rate plus 50 basis points, discounted to the redemption date on a semi-annual basis, over (b) the principal amount of such note.

The indenture governing the 2022 Notes contains affirmative and negative covenants that, among other things, limit the ability of the Company and its subsidiaries that guarantee notes to incur indebtedness; purchase or redeem stock or subordinated indebtedness; make investments; create liens; enter into transactions with affiliates; sell assets; refinance certain indebtedness; merge with or into other companies or transfer substantially all of their assets; and, in certain circumstances, to pay dividends or make other distributions on stock. With respect to indebtedness, the indenture limits the Company's ability to incur additional indebtedness, including borrowings under its Senior Credit Agreement, unless the Company meets one of two tests: the fixed charge coverage ratio test, which requires that after giving effect to the incurrence of additional debt the ratio of the Company's adjusted consolidated EBITDA (as defined in the indenture) to its adjusted consolidated interest expense over the trailing four fiscal quarters will be at least 2.0 to 1.0; or, in the alternative, the Company may incur additional debt under Credit Facilities (as defined in the indenture) if the amount of such additional indebtedness is not more than the greater of a fixed sum of $750 million or 30% of the Company's adjusted consolidated net tangible assets (as defined in the indenture), which is determined primarily by the value of discounted future net revenues from proved oil and natural gas reserves as of the date of such determination.

8.875% Senior Notes

On November 6, 2012, the Company issued $750.0 million aggregate principal amount of its 8.875% senior notes due 2021 (the 2021 Notes), at a price to the initial purchasers of 99.247% of par. The net proceeds from the offering of approximately $725.6 million (after deducting the initial purchasers' discounts, commissions and offering expenses) were used to fund a portion of the cash consideration paid in the acquisition of two wholly-owned subsidiaries of Petro-Hunt Holdings, LLC and Pillar Holdings, LLC, which owned acreage prospective for the Bakken / Three Forks formations located in North Dakota, in Williams, Mountrail, McKenzie and Dunn Counties.

On January 14, 2013, the Company issued an additional $600.0 million aggregate principal amount of the 2021 Notes at a price to the initial purchasers of 105% of par. The net proceeds from the sale of the additional 2021 Notes of approximately $619.5 million (after the initial purchasers' premiums, commissions and offering expenses) were used to repay all of the then outstanding borrowings under the Senior Credit Agreement and for general corporate purposes, including funding a portion of the Company's 2013 capital expenditures program. These notes were issued as "additional notes" under the indenture governing the 2021 Notes and under the indenture are treated as a single series with substantially identical terms as the 2021 Notes previously issued.

The 2021 Notes bear interest at a rate of 8.875% per annum, payable semi- annually on May 15 and November 15 of each year, beginning on May 15, 2013. The Notes will mature on May 15, 2021. The 2021 Notes are senior unsecured obligations of the Company and rank equally with all of its

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. LONG-TERM DEBT (Continued)

current and future senior indebtedness. The 2021 Notes are jointly and severally, fully and unconditionally guaranteed on a senior unsecured basis by the Company's existing 100% owned subsidiaries, except for one subsidiary, HK TMS, LLC. Halcón, the issuer of the 2021 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

On June 4, 2013, the Company completed a registered exchange offer of outstanding 2021 Notes for new registered notes having terms substantially identical to the 2021 Notes.

On or before November 15, 2015, the Company may redeem up to 35% of the aggregate principal amount of the 2021 Notes with the net cash proceeds of certain equity offerings at a redemption price of 108.875% of the principal amount plus accrued and unpaid interest to the redemption date provided that: at least 65% in aggregate principal amount of the 2021 Notes originally issued remains outstanding immediately after the redemption and the redemption occurs within 180 days of the date of closing of the related equity offering. In addition, at any time prior to November 15, 2016, the Company may redeem some or all of the 2021 Notes for the principal amount thereof, plus accrued and unpaid interest plus a make whole premium equal to the excess, if any of (a) the present value at such time of (i) the redemption price of such note at November 15, 2016, plus (ii) any required interest payments due on the notes through November 15, 2016 (excluding currently accrued and unpaid interest) computed using a discount rate equal to the Treasury Rate plus 50 basis points, discounted to the redemption date on a semi-annual basis, over (b) the principal amount of such note.

In conjunction with the issuance of the 2021 Notes, the Company recorded a discount of approximately $5.7 million to be amortized over the remaining life of the 2021 Notes using the effective interest method. The remaining unamortized discount was $4.7 million at September 30, 2014. In conjunction with the issuance of the additional 2021 Notes, the Company recorded a premium of approximately $30.0 million to be amortized over the remaining life of the additional 2021 Notes using the effective interest method. The remaining unamortized premium was $25.4 million at September 30, 2014.

The indenture governing the 2021 Notes contains affirmative and negative covenants that are substantially the same as those contained in the indenture governing the 9.25% senior notes, described above.

9.75% Senior Notes

On July 16, 2012, the Company issued $750.0 million aggregate principal amount of 9.75% senior notes due 2020 issued at 98.646% of par (the 2020 Notes). The net proceeds from the offering were approximately $723.1 million after deducting the initial purchasers' discounts, commissions and offering expenses and were used to fund a portion of the cash consideration paid in the merger with GeoResources, Inc., and the acquisition of certain oil and gas leaseholds located in East Texas.

On December 19, 2013, the Company issued an additional $400.0 million aggregate principal amount of the 2020 Notes at a price to the initial purchasers of 102.750% of par. The net proceeds from the sale of the additional 2020 Notes of approximately $406.3 million (after the initial purchasers' fees, commissions and offering expenses) were used to repay a portion of the then outstanding borrowings under the Senior Credit Agreement. These notes were issued as "additional notes" under the indenture governing the 2020 Notes and under the indenture are treated as a single series with substantially identical terms as the 2020 Notes previously issued.

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. LONG-TERM DEBT (Continued)

The 2020 Notes bear interest at a rate of 9.75% per annum, payable semi- annually on January 15 and July 15 of each year, beginning on January 15, 2013. The 2020 Notes will mature on July 15, 2020. The 2020 Notes are senior unsecured obligations of the Company and rank equally with all of its current and future senior indebtedness. The 2020 Notes are jointly and severally, fully and unconditionally guaranteed on a senior unsecured basis by the Company's existing 100% owned subsidiaries, except for one subsidiary, HK TMS, LLC. Halcón, the issuer of the 2020 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

On June 4, 2013, the Company completed a registered exchange offer of the outstanding 2020 Notes originally issued, for new registered notes having terms substantially identical to the original 2020 Notes. On May 23, 2014, the Company completed a registered exchange offer of the outstanding additional 2020 Notes for new registered notes having terms substantially identical to the additional 2020 Notes.

On or before July 15, 2015, the Company may redeem up to 35% of the aggregate principal amount of the 2020 Notes with the net cash proceeds of certain equity offerings at a redemption price of 109.750% of the principal amount plus accrued and unpaid interest to the redemption date provided that: at least 65% in aggregate principal amount of the 2020 Notes originally issued remains outstanding immediately after the redemption and the redemption occurs within 180 days of the equity offering. In addition, at any time prior to July 15, 2016, the Company may redeem some or all of the 2020 Notes for the principal amount thereof, plus accrued and unpaid interest plus a make whole premium equal to the excess , if any of (a) the present value at such time of (i) the redemption price of such note at July 15, 2016, plus (ii) any required interest payments due on the notes through July 15, 2016 (excluding currently accrued and unpaid interest) computed using a discount rate equal to the Treasury Rate plus 50 basis points, discounted to the redemption date on a semi-annual basis, over (b) the principal amount of such note.

In conjunction with the issuance of the 2020 Notes, the Company recorded a discount of approximately $10.2 million to be amortized over the remaining life of the 2020 Notes using the effective interest method. The remaining unamortized discount was $8.1 million at September 30, 2014. In conjunction with the issuance of the additional 2020 Notes, the Company recorded a premium of approximately $11.0 million to be amortized over the remaining life of the additional 2020 Notes using the effective interest method. The remaining unamortized premium was approximately $10.0 million at September 30, 2014.

The indenture governing the 2020 Notes contains affirmative and negative covenants that are substantially the same as those contained in the indenture governing the 9.25% senior notes, described above.

8.0% Convertible Note

On February 8, 2012, the Company issued the 2017 Note in the principal amount of $275.0 million together with five year warrants (February 2012 Warrants) for an aggregate purchase price of $275.0 million. The 2017 Note bears interest at a rate of 8% per annum, payable quarterly on March 31, June 30, September 30 and December 31 of each year and matures on February 8, 2017. Through the March 31, 2014 interest payment date, the Company was permitted to elect to pay the interest in kind, by adding to the principal of the 2017 Note, all or any portion of the interest due on the 2017 Note. The Company elected to pay the interest in kind on March 31, June 30 and

Table of Contents

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. LONG-TERM DEBT (Continued)

September 30, 2012, and added $3.2 million, $5.7 million and $5.8 million of interest incurred during the first, second and third quarters of 2012, respectively, into the 2017 Note, increasing the principal amount to $289.7 million. The Company did not elect to pay-in-kind interest for the quarterly payments due subsequent to September 30, 2012. As of February 8, 2014, holders of the 2017 Note became entitled to convert at their election each $4.50 of principal and accrued but unpaid interest into one share of the Company's common stock. The 2017 Note is a senior unsecured obligation of the Company.

The Company allocated the proceeds received for the 2017 Note and February 2012 Warrants on a relative fair value basis. Consequently, the Company recorded a discount of $43.6 million to be amortized over the remaining life of the 2017 Note utilizing the effective interest rate method. The remaining unamortized discount was $24.0 million at September 30, 2014.

Debt Issuance Costs

The Company capitalizes certain direct costs associated with the issuance of long-term debt and amortizes such costs over the lives of the respective debt. During the three months ended September 30, 2014, the Company capitalized $0.7 million of debt issuance costs associated with the Eighth Amendment to its Senior Credit Agreement. At September 30, 2014 and December 31, 2013, the Company had approximately $58.0 million and $64.3 million, respectively, of unamortized debt issuance costs.

5. FAIR VALUE MEASUREMENTS

Pursuant to ASC 820, the Company's determination of fair value incorporates not only the credit standing of the counterparties involved in transactions with the Company resulting in receivables on the Company's unaudited condensed consolidated balance sheets, but also the impact of the Company's nonperformance risk on its own liabilities. ASC 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). ASC 820 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy assigns the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 measurements are inputs that are observable for assets or liabilities, either directly or indirectly, other than quoted prices included within Level 1. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The Company classifies fair value balances based on the observability of those inputs.

The following tables set forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value as of September 30, 2014 and December 31, 2013. As required by ASC 820, a financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There were no transfers between fair value hierarchy levels for the nine months ended September 30, 2014.

Table of Contents

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. FAIR VALUE MEASUREMENTS (Continued)

	September 30, 2014			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets				
Receivables from derivative contracts	$	$ 43,859	$	$ 43,859
Liabilities				
Liabilities from derivative contracts	$	$ 16,001	$ 2,836	$ 18,837

	December 31, 2013			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets				
Receivables from derivative contracts	$	$ 24,762	$	$ 24,762
Liabilities				
Liabilities from derivative contracts	$	$ 34,376	$ 2,816	$ 37,192

Derivative contracts listed above as Level 2 include collars, swaps and put options that are carried at fair value. The Company records the net change in the fair value of these positions in *"Net gain (loss) on derivative contracts"* in the Company's unaudited condensed consolidated statements of operations. The Company is able to value the assets and liabilities based on observable market data for similar instruments, which resulted in the Company reporting its derivatives as Level 2. This observable data includes the forward curves for commodity prices based on quoted markets prices and implied volatility factors related to changes in the forward curves. See Note 6, *"Derivative and Hedging Activities"* for additional discussion of derivatives.

Derivative contracts listed above as Level 3 include extendable collars that are carried at fair value. The significant unobservable inputs for these Level 3 contracts include unpublished forward strip prices and market volatilities. The following table sets forth a reconciliation of changes in the fair value of the Company's extendable collar contracts classified as Level 3 in the fair value hierarchy (in thousands):

	Significant Unobservable Inputs (Level 3)

		September 30, 2014		December 31, 2013
Beginning Balance	$	(2,816)	$	
Net gain (loss) on derivative contracts		(20)		(2,816)
Settlements				
Purchase of derivative contracts				
Buy out of derivative contracts				
Ending Balance	$	(2,836)	$	(2,816)

Change in unrealized gains (losses) included in earnings related to derivatives still held at September 30, 2014 and December 31, 2013	$	(20)	$	(2,816)

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. FAIR VALUE MEASUREMENTS (Continued)

As of September 30, 2014 and December 31, 2013, the Company's derivative contracts were with major financial institutions with investment grade credit ratings which are believed to have a minimal credit risk. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts; however, the Company does not anticipate such nonperformance. Each of the counterparties to the Company's current derivative contracts is a lender or an affiliate of a lender in the Company's Senior Credit Agreement. The Company did not post collateral under any of these contracts as they are secured under the Senior Credit Agreement.

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of ASC 825, *Financial Instruments*. The estimated fair value amounts have been determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. The estimated fair value of the Company's Senior Credit Agreement approximates carrying value because the interest rates approximate current market rates. The following table presents the estimated fair values of the Company's fixed interest rate, long-term debt instruments as of September 30, 2014 and December 31, 2013 (excluding discounts, premiums and deferred premiums on derivative contracts):

	September 30, 2014		December 31, 2013	
Debt	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
		(In thousands)		
9.25% $400 million senior notes	$ 400,000	$ 400,600	$ 400,000	$ 407,432
8.875% $1.35 billion senior notes	1,350,000	1,329,750	1,350,000	1,390,500
9.75% $1.15 billion senior notes	1,150,000	1,170,125	1,150,000	1,197,438
8.0% $289.7 million convertible note	289,669	343,094	289,669	368,418
	$ 3,189,669	$ 3,243,569	$ 3,189,669	$ 3,363,788

The fair value of the Company's fixed interest debt instruments was calculated using Level 2 criteria at September 30, 2014 and December 31, 2013. The fair value of the Company's senior notes is based on quoted market prices from trades of such debt. The fair value of the Company's convertible note is based on published market prices and risk-free rates.

On June 16, 2014, the Company entered into a transaction to develop its Tuscaloosa Marine Shale assets with funds and accounts managed by affiliates of Apollo Global Management, LLC. See Note 9, *"Mezzanine Equity,"* for a discussion of the valuation approach used to allocate the investment proceeds to the transaction's components, for the classification of the estimate within the fair value hierarchy, and for a reconciliation of the beginning and ending liability balances for the tranche rights and the embedded derivative.

During the three months ended September 30, 2013, the Company recorded a non-cash impairment charge of $67.3 million related to its gas gathering systems. See Note 1, *"Financial Statement Presentation,"* for a discussion of the valuation approach used and the classification of the estimate within the fair value hierarchy.

As of July 1, 2013, the Company performed its annual goodwill impairment test which involved the fair value estimation of the Company's reporting unit. See Note 1, *"Financial Statement Presentation,"*

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. FAIR VALUE MEASUREMENTS (Continued)

for a discussion of the valuation approaches used and the classification of the estimate within the fair value hierarchy.

The Company follows the provisions of ASC 820, for nonfinancial assets and liabilities measured at fair value on a non-recurring basis. These provisions apply to the Company's initial recognition of asset retirement obligations for which fair value is used. The asset retirement obligation estimates are derived from historical costs and management's expectation of future cost environments; and therefore, the Company has designated these liabilities as Level 3. See Note 7, "*Asset Retirement Obligations,"* for a reconciliation of the beginning and ending balances of the liability for the Company's asset retirement obligations.

6. DERIVATIVE AND HEDGING ACTIVITIES

The Company is exposed to certain risks relating to its ongoing business operations, such as commodity price risk and interest rate risk. Derivative contracts are utilized to economically hedge the Company's exposure to price fluctuations and reduce the variability in the Company's cash flows associated with anticipated sales of future oil and natural gas production. The Company generally hedges a substantial, but varying, portion of anticipated oil and natural gas production for future periods. Derivatives are carried at fair value on the unaudited condensed consolidated balance sheets as assets or liabilities, with the changes in the fair value included in the unaudited condensed consolidated statements of operations for the period in which the change occurs. Historically, the Company has also entered into interest rate swaps to mitigate exposure to market rate fluctuations. The Company does not enter into derivative contracts for speculative trading purposes.

It is the Company's policy to enter into derivative contracts, including interest rate derivatives, only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. Each of the counterparties to the Company's current derivative contracts is a lender or an affiliate of a lender in its Senior Credit Agreement. The Company did not post collateral under any of these contracts as they are secured under the Company's Senior Credit Agreement.

At September 30, 2014 and December 31, 2013, the Company's crude oil and natural gas derivative positions consisted of swaps, swaptions, costless put/call "collars," extendable costless collars and put options. Swaps are designed so that the Company receives or makes payments based on a differential between fixed and variable prices for crude oil and natural gas. A costless collar consists of a sold call, which establishes a maximum price the Company will receive for the volumes under contract and a purchased put that establishes a minimum price. Extendable collars are costless put/call contracts that may be extended annually at the option of the counterparty on a designated date. A sold put option limits the exposure of the counterparty's risk should the price fall below the strike price. Sold put options limit the effectiveness of purchased put options at the low end of the put/call collars to market prices in excess of the strike price of the put option sold. Swaptions are swap contracts that may be extended annually at the option of the counterparty on a designated date. The Company has elected not to designate any of its derivative contracts for hedge accounting. Accordingly, the Company records the net change in the mark- to-market valuation of these derivative contracts, as well as all payments and receipts on settled derivative contracts, in *"Net gain (loss) on derivative contracts"* on the unaudited condensed consolidated statements of operations.

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. DERIVATIVE AND HEDGING ACTIVITIES (Continued)

At September 30, 2014, the Company had 110 open commodity derivative contracts summarized in the following tables: 10 natural gas collar arrangements, 69 crude oil collar arrangements, 19 crude oil swaps, one crude oil put option, one crude oil call option, eight crude oil swaptions and two crude oil extendable collars.

At December 31, 2013, the Company had 86 open commodity derivative contracts summarized in the following tables: 10 natural gas collar arrangements, 52 crude oil collar arrangements, five crude oil three-way collars, one crude oil put option, eight crude oil swaps, eight crude oil swaptions and two crude oil extendable collars.

All derivative contracts are recorded at fair market value in accordance with ASC 815 and ASC 820 and included in the unaudited condensed consolidated balance sheets as assets or liabilities. The following table summarizes the location and fair value amounts of all derivative contracts in the unaudited condensed consolidated balance sheets as of September 30, 2014 and December 31, 2013:

	Asset derivative contracts			Liability derivative contracts		
Derivatives not designated as hedging contracts under ASC 815	**Balance sheet**	**September 30, 2014**	**December 31, 2013**	**Balance sheet**	**September 30, 2014**	**December 31, 2013**
		(In thousands)			**(In thousands)**	
Commodity contracts	Current assets receivables from derivative contracts	$ 19,715	$ 2,028	Current liabilities liabilities from derivative contracts	$ (1,208)	$ (17,859)
Commodity contracts	Other noncurrent assets receivables from derivative contracts	24,144	22,734	Other noncurrent liabilities liabilities from derivative contracts	(17,629)	(19,333)
Total derivatives not designated as hedging contracts under ASC 815		$ 43,859	$ 24,762		$ (18,837)	$ (37,192)

The following table summarizes the location and amounts of the Company's realized and unrealized gains and losses on derivative contracts in the Company's unaudited condensed consolidated statements of operations:

Derivatives not designated as hedging contracts under ASC 815	**Location of gain or (loss) recognized in income on derivative contracts**	**Amount of gain or (loss) recognized in income on derivative contracts for the Three Months Ended September 30,**		**Amount of gain or (loss) recognized in income on derivative contracts for the Nine Months Ended September 30,**	
		2014	**2013**	**2014**	**2013**
		(In thousands)		**(In thousands)**	
Commodity contracts:					
Unrealized gain (loss) on commodity contracts	Other income (expenses) net gain (loss) on derivative	$ 169,713	$ (38,095)	$ 36,900	$ (20,379)

	contracts				
Realized gain (loss) on commodity contracts	Other income (expenses) net gain (loss) on derivative contracts	(6,426)	(16,332)	(28,311)	(18,370)
Total net gain (loss) on derivative contracts	Other income (expenses) net gain (loss) on derivative contracts	$ 163,287	$ (54,427)	$ 8,589	$ (38,749)

24

Table of Contents

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. DERIVATIVE AND HEDGING ACTIVITIES (Continued)

At September 30, 2014 and December 31, 2013, the Company had the following open crude oil and natural gas derivative contracts:

				September 30, 2014							
				Floors		Ceilings		Put Options		Call Options	
Period	Instrument	Commodity	Volume in Mmbtu's/ Bbl's	Price / Price Range	Weighted Average Price	Price / Price Range	Weighted Average Price	Price / Price Range	Weighted Average Price	Price / Price Range	Weighted Average Price
October 2014 - December 2014	Call	Crude Oil	92,000	$	$	$	$	$	$	$ 95.00	$ 95.00
October 2014 - December 2014	Collars	Crude Oil	2,369,000	85.00 - 95.00	88.83	92.50 - 108.45	96.58				
October 2014 - December 2014	Collars	Natural Gas	2,990,000	3.75 - 4.00	3.85	4.26 - 4.55	4.35				
October 2014 - December 2014	Put	Crude Oil	92,000					90.00	90.00		
October 2014 - December 2014	Swaps	Crude Oil	138,000	96.00 - 96.17	96.11						
January 2015 - June 2015	Collars	Crude Oil	1,583,750	85.00 - 90.00	86.29	91.00 - 98.50	93.14				
January 2015 - December 2015	Collars	Natural Gas	6,387,500	4.00	4.00	4.55 - 4.85	4.68				
January 2015 - December 2015[(1)]	Collars	Crude Oil	6,205,000	82.50 - 90.00	86.47	90.00 - 100.25	94.39				
January 2015 - December 2015[(2)]	Swaps	Crude Oil	1,825,000	91.00 - 92.75	91.76						
March 2015 - December 2015	Collars	Crude Oil	306,000	87.50	87.50	92.50	92.50				
April 2015 - December 2015	Collars	Crude Oil	412,500	87.50	87.50	92.50	92.50				
July 2015 - December 2015	Collars	Crude Oil	1,104,000	85.00 - 87.50	85.83	90.00 - 92.50	90.92				
January 2016 - June 2016	Collars	Crude Oil	182,000	90.00	90.00	96.85	96.85				
January 2016 - December 2016	Collars	Crude Oil	1,830,000	87.50 - 90.00	88.55	92.70 - 95.10	93.84				
January 2016 - December 2016	Collars	Natural Gas	732,000	4.00	4.00	4.22	4.22				
January 2016 - December 2016[(3)]	Swaps	Crude Oil	4,026,000	88.00 - 91.73	89.65						

(1) *Includes an outstanding crude oil collar which may be extended at a floor of $85.00 per Bbl and a ceiling of $96.20 per Bbl for a total of 732,000 Bbls for the year ended December 31, 2016. Also includes an outstanding crude oil collar which may be extended at a floor of $85.00 per Bbl and a ceiling of $96.00 per Bbl for a total of 366,000 Bbls for the year ended December 31, 2016.*

(2) *Includes an outstanding crude oil swap of which may be extended at a price of $91.25 per Bbl for 732,000 Bbls for the year ended December 31, 2016. Also includes certain outstanding crude oil swaps which may be extended at a price of $91.00 per Bbl totaling 366,000 Bbls for the year ended December 31, 2016.*

(3) *Includes an outstanding crude oil swap which may be extended at a price of $88.25 per Bbl for a total of 730,000 Bbls for the year ended December 31, 2017. Also includes certain outstanding crude oil swaps which may be extended at a price of $88.00 per Bbl totaling 912,500 Bbls for the year ended December 31, 2017. Includes an outstanding crude oil swap which may be extended at a price of $88.87 per Bbl totaling 547,500 Bbls for the year ended December 31, 2017.*

				December 31, 2013					
				Floors		Ceilings		Put Options	
Period	Instrument	Commodity	Volume in Mmbtu's/ Bbl's	Price / Price Range	Weighted Average Price	Price / Price Range	Weighted Average Price	Price / Price Range	Weighted Average Price
January 2014 - March 2014	Three-Way Collars	Crude Oil	144,000	$95.00	$ 95.00	$98.60 - 109.50	$ 100.03	$ 70.00	$ 70.00
January 2014 - June 2014	Collars	Crude Oil	724,000	90.00	90.00	96.50 - 99.50	98.00		
January 2014 - December 2014	Collars	Crude Oil	7,573,750	85.00 - 95.00	88.67	93.60 - 108.45	96.22		
January 2014 - December 2014	Collars	Natural Gas	11,862,500	3.75 - 4.00	3.85	4.26 - 4.55	4.35		
April 2014 - June 2014	Three-Way Collars	Crude Oil	136,500	95.00	95.00	98.20 - 101.00	99.13	70.00	70.00
July 2014 - December 2014	Collars	Crude Oil	920,000	87.50 - 90.00	89.50	92.50 - 100.25	97.87		
July 2014 - December 2014	Collars	Natural Gas	920,000	4.00	4.00	4.42	4.42		
July 2014 - December 2014	Put	Crude Oil	184,000					90.00	90.00
January 2015 - June 2015	Collars	Crude Oil	1,583,750	85.00 - 90.00	86.29	91.00 - 98.50	93.14		
January 2015 - December 2015(1)	Collars	Crude Oil	5,110,000	82.50 - 90.00	86.07	90.00 - 100.25	94.65		
January 2015 - December 2015	Collars	Natural Gas	6,387,500	4.00	4.00	4.55 - 4.85	4.68		
January 2015 - December 2015(2)	Swaps	Crude Oil	1,095,000	91.00 - 91.25	91.17				
January 2016 - December 2016(3)	Swaps	Crude Oil	2,190,000	88.00 - 88.87	88.30				

(1) *Includes an outstanding crude oil collar which may be extended at a floor of $85.00 per Bbl and a ceiling of $96.20 per Bbl for a total of 730,000 Bbls for the year ended December 31, 2016. Also includes an outstanding crude oil collar which may be extended at a floor of $85.00 per Bbl and a ceiling of $96.00 per Bbl for a total of 365,000 Bbls for the year ended December 31, 2016.*

(2) *Includes an outstanding crude oil swap which may be extended at a price of $91.25 per Bbl for 730,000 Bbls for the year ended December 31, 2016. Also includes certain outstanding crude oil swaps which may be extended at a price of $91.00 per Bbl totaling 365,000 Bbls for the year ended December 31, 2016.*

(3) *Includes an outstanding crude oil swap which may be extended at a price of $88.25 per Bbl for a total of 730,000 Bbls for the year ended December 31, 2017. Also includes certain outstanding crude oil swaps which may be extended at a price of $88.00 per Bbl totaling 912,500 Bbls for the year ended December 31, 2017. Includes an outstanding crude oil swap which may be extended at a price of $88.87 per Bbl totaling 547,500 Bbls for the year ended December 31, 2017.*

The Company presents the fair value of its derivative contracts at the gross amounts in the unaudited condensed consolidated balance sheets. The following table shows the potential effects of

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. DERIVATIVE AND HEDGING ACTIVITIES (Continued)

master netting arrangements on the fair value of the Company's derivative contracts at September 30, 2014 and December 31, 2013:

Offsetting of Derivative Assets and Liabilities	Derivative Assets September 30, 2014	Derivative Assets December 31, 2013	Derivative Liabilities September 30, 2014	Derivative Liabilities December 31, 2013
	(In thousands)		(In thousands)	
Gross Amounts Presented in the Consolidated Balance Sheet	$ 43,859	$ 24,762	$ (18,837)	$ (37,192)
Amounts Not Offset in the Consolidated Balance Sheet	(18,263)	(20,036)	17,762	19,507
Net Amount	$ 25,596	$ 4,726	$ (1,075)	$ (17,685)

The Company enters into an International Swap Dealers Association Master Agreement (ISDA) with each counterparty prior to a derivative contract with such counterparty. The ISDA is a standard contract that governs all derivative contracts entered into between the Company and the respective counterparty. The ISDA allows for offsetting of amounts payable or receivable between the Company and the counterparty, at the election of both parties, for transactions that occur on the same date and in the same currency.

7. ASSET RETIREMENT OBLIGATIONS

The Company records an asset retirement obligation (ARO) when it can reasonably estimate the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon costs. For gas gathering systems and equipment, the Company records an ARO when the system is placed in service and it can reasonably estimate the fair value of an obligation to perform site reclamation and other necessary work when it is required. The Company records the ARO liability on the unaudited condensed consolidated balance sheets and capitalizes a portion of the cost in *"Oil and natural gas properties"* or *"Other operating property and equipment"* during the period in which the obligation is incurred. The Company records the accretion of its ARO liabilities in *"Depletion, depreciation and accretion"* expense in the unaudited condensed consolidated statements of operations. The additional capitalized costs are depreciated on a unit-of-production basis or straight-line basis.

The Company recorded the following activity related to its ARO liability for the nine months ended September 30, 2014 (in thousands, inclusive of the current portion):

Liability for asset retirement obligations as of December 31, 2013	$ 39,257
Liabilities settled and divested[(1)]	(8,277)
Additions	3,205
Acquisitions	181
Accretion expense	1,375
Revisions in estimated cash flows	154
Liability for asset retirement obligations as of September 30, 2014	$ 35,895

(1) *See Note 2, "Acquisitions and Divestitures" for additional information on the Company's divestiture activities.*

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. COMMITMENTS AND CONTINGENCIES

Commitments

The Company leases corporate office space in Houston, Texas; Tulsa, Oklahoma; and Denver, Colorado as well as a number of other field office locations. Rent expense was approximately $6.0 million and $6.8 million for the nine months ended September 30, 2014 and 2013, respectively. In addition, the Company has commitments for certain equipment under long-term operating lease agreements, namely drilling rigs as well as pipeline and well equipment, with various expiration dates through 2018. Early termination of the drilling rig commitments would result in termination penalties approximating $63.7 million, which would be in lieu of the remaining $109.9 million of drilling rig commitments as of September 30, 2014. As of September 30, 2014, the amount of commitments under office and equipment lease agreements is consistent with the levels at December 31, 2013, as disclosed in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2013, approximating $62.2 million in the aggregate, and containing various expiration dates through 2024.

The Company has entered into various long-term gathering, transportation and sales contracts in its Bakken / Three Forks formations in North Dakota. As of September 30, 2014, the Company had in place nine long-term crude oil contracts and two long-term natural gas contracts in this area. Under the terms of these contracts, the Company has committed a substantial portion of its Bakken / Three Forks production for periods ranging from five to ten years from the date of first production. The sales prices under these contracts are based on posted market rates. The Company believes that there are sufficient available reserves and supplies in the Bakken / Three Forks formations to meet its commitments. Historically, the Company has been able to meet its delivery commitments.

On December 20, 2013, the Company entered into a carry and earning agreement, as amended (the Agreement) with an independent third party (Seller) associated with the acquisition of certain properties believed to be prospective for the Tuscaloosa Marine Shale (TMS), primarily in Wilkinson County, Mississippi and in West Feliciana and East Feliciana Parishes, Louisiana. The Agreement required the Company to fund up to $189.4 million (the Carry Amount) in exchange for approximately 117,870 net acres. The Company paid $62.5 million of the Carry Amount at closing on February 28, 2014 and the remaining $126.9 million during the three months ended June 30, 2014, reflected as *"Advance on carried interest"* in the accompanying unaudited condensed consolidating statements of cash flows. The Carry Amount is to be used by the Seller to fund wells prospective for the TMS to be drilled by the Seller (the Carry Wells) on the Seller's retained acreage. As part of the transaction, the Company will also receive a 5% working interest in the Carry Wells. Any portion of the Carry Amount not spent by the Seller, in accordance with the Agreement, on or before August 31, 2017, will be returned to the Company.

On June 16, 2014, the Company entered into a transaction to develop its TMS assets with funds and accounts managed by affiliates of Apollo Global Management, LLC. See Note 9, "*Mezzanine Equity,"* for a discussion of the drilling obligation associated with the transaction.

Contingencies

From time to time, the Company may be a plaintiff or defendant in a pending or threatened legal proceeding arising in the normal course of its business. While the outcome and impact of currently pending legal proceedings cannot be determined, the Company's management and legal counsel believe that the resolution of these proceedings through settlement or adverse judgment will not have a material effect on the Company's unaudited condensed consolidated operating results, financial position or cash flows.

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. MEZZANINE EQUITY

On June 16, 2014, funds and accounts managed by affiliates of Apollo Global Management, LLC (Apollo) contributed $150 million in cash to HK TMS, LLC, a wholly owned Delaware limited liability company (HK TMS), that, as of June 16, 2014 holds all of the Company's undeveloped acreage in Mississippi and Louisiana that management believes is prospective for the TMS formation, in exchange for the issuance by HK TMS of 150,000 preferred shares. At the closing, the Company also contributed $50 million in cash to HK TMS. Holders of the HK TMS preferred shares will receive quarterly cash dividends of 8% cumulative perpetual per annum, subject to HK TMS' option to pay such dividends "in-kind" through the issuance of additional preferred shares. For the nine months ended September 30, 2014, HK TMS paid Apollo approximately $3.5 million in cash dividends. The cash dividends are presented within "*Preferred dividends on redeemable noncontrolling interest"* on the condensed consolidated statements of operations. The preferred shares will be automatically redeemed and cancelled when the holders receive cash dividends and distributions on the preferred shares equating to the greater of a 12% annual rate of return plus principal and 1.25 times their investment plus applicable fees (the Redemption Price), subject to adjustment under certain circumstances. The preferred shares have a liquidation preference in the event of dissolution in an amount equal to the redemption price plus any unpaid dividends not otherwise included in the calculation of the redemption price through the date of liquidation payment. If the preferred shares remain outstanding after June 16, 2018 Apollo can require HK TMS to redeem the preferred shares at the Redemption Price. HK TMS may also redeem the preferred shares at any time by paying the Redemption Price, or may be required to redeem the preferred shares for the Redemption Price plus certain fees under certain circumstances. The preferred shares have been classified as "*Redeemable noncontrolling interest*" and included in *"Mezzanine equity"* between total liabilities and shareholders' equity on the unaudited condensed consolidated balance sheets pursuant to ASC 480-10-S99-3A. The preferred shares, while not currently redeemable, are considered probable of becoming redeemable and therefore will be subsequently remeasured each reporting period by accreting the initial value to the estimated required redemption value through June 16, 2018. The accretion is presented as a deemed dividend and recorded in "*Redeemable noncontrolling interest*" on the condensed consolidated balance sheet and within "*Preferred dividends on redeemable noncontrolling interest"* on the condensed consolidated statements of operations. In accordance with ASC 480-10-S99-3A, an adjustment to the carrying amount presented in mezzanine equity will be recognized as charges against retained earnings and will reduce income available to common shareholders in the calculation of earnings per share. Adjustments to the carrying amount may not be necessary if the application of ASC 810 results in a noncontrolling interest balance in excess of what is required pursuant to ASC 480-10-S99-3A.

Under certain circumstances, Apollo may acquire up to an additional 250,000 preferred shares of HK TMS on the same terms, with HK TMS receiving up to an additional $250 million in cash proceeds (Tranche Rights). The Tranche Rights have been recognized separately as a liability instrument within *"Other noncurrent liabilities"* in the unaudited condensed consolidated balance sheets, in accordance with ASC 480 as the shares underlying the Tranche Rights are redeemable equity instruments. The Tranche Rights will be subsequently remeasured at fair value each reporting period in accordance with ASC 480, with fair value changes recorded in *"Interest expense and other, net"* on the condensed consolidated statements of operations.

In conjunction with the issuance of the preferred shares, HK TMS conveyed a 4.0% overriding royalty interest (ORRI), subject to reduction to 2.0% under certain circumstances, in 75 net wells to be drilled and completed on its TMS acreage. The number of wells subject to the ORRI will increase to

Table of Contents

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. MEZZANINE EQUITY (Continued)

the extent that Apollo subscribes for additional preferred shares, with a maximum of 200 net operated wells subject to such ORRI if Apollo subscribes for the full additional 250,000 preferred shares. The ORRI has been recognized separately as a conveyance of oil and natural gas properties in *"Unevaluated properties"* on the unaudited condensed consolidated balance sheets and within *"Proceeds received from the sale of oil and natural gas assets"* on the unaudited condensed consolidated statements of cash flows. The Company has committed to drill a minimum of 6.5 net wells in each of the six consecutive twelve month periods beginning June 16, 2014.

Of the $150 million initial investment proceeds from Apollo, the Company allocated the proceeds as follows (in thousands):

HK TMS, LLC preferred stock	$	110,051
Tranche rights		4,516
Overriding royalty interest		34,576
Embedded derivative		857
Total initial investment proceeds	$	150,000

For purposes of estimating the fair values of the transaction components, an income approach was used that estimated fair value based on the anticipated cash flows associated with the Company's proved reserves, discounted using a weighted average cost of capital rate. The estimation of the fair value of these components includes the use of unobservable inputs, such as estimates of proved reserves, the weighted average cost of capital (discount rate), estimated future revenues, and estimated future capital and operating costs. The use of these unobservable inputs results in the fair value estimates being classified as Level 3. Although the Company believes the assumptions and estimates used in the fair value calculation of the transaction components are reasonable and appropriate, different assumptions and estimates could materially impact the analysis and resulting conclusions. The assumptions used in estimating the fair value of the transaction components are inherently uncertain and require management judgment. The following table sets forth a reconciliation of the changes in fair value of the Tranche Rights and embedded derivative classified as Level 3 in the fair value hierarchy (in thousands):

		Tranche rights		Embedded derivative
Balances at June 30, 2014	$	4,516	$	857
Change in fair value		151		35
Balances at September 30, 2014	$	4,667	$	892

As part of the transaction, HK TMS is required to maintain a minimum cash balance equal to two quarterly dividend payments, of approximately $3.0 million each, plus $10.0 million, which is presented on the unaudited condensed consolidated balance sheets in *"Restricted cash."*

Table of Contents

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. MEZZANINE EQUITY (Continued)

The Company recorded the following activity related to the preferred shares recorded in *"Mezzanine equity"* for the nine months ended September 30, 2014 (in thousands, except share amounts):

	Redeemable noncontrolling interest (Mezzanine equity)		
	Shares		Amount
Balances at December 31, 2013		$	
Issuance of HK TMS, LLC preferred stock	150,000		110,051
Offering costs			(2,544)
Deemed dividends on redeemable noncontrolling interest			3,201
Balances at September 30, 2014	150,000	$	110,708

10. STOCKHOLDERS' EQUITY

5.75% Series A Convertible Perpetual Preferred Stock

On June 18, 2013, the Company completed its offering of 345,000 shares of its 5.75% Series A Convertible Perpetual Preferred Stock (the Series A Preferred Stock) at a public offering price of $1,000 per share (the Liquidation Preference). The net proceeds to the Company were approximately $335.2 million, after deducting the underwriting discount and offering expenses. The Company used the net proceeds to repay a portion of the outstanding borrowings under its Senior Credit Agreement.

Holders of the Series A Preferred Stock are entitled to receive, when, as and if declared by the Company's Board of Directors, cumulative dividends at the rate of 5.75% per annum (the dividend rate) on the Liquidation Preference per share of the Series A Preferred Stock, payable quarterly in arrears on each dividend payment date. Dividends may be paid in cash or, where freely transferable by any non-affiliate recipient thereof, in common stock of the Company, or a combination thereof, and are payable on March 1, June 1, September 1 and December 1 of each year. On September 2, 2014, the Company incurred cumulative, declared dividends of $5.0 million by issuing approximately 1.0 million shares of common stock. For the nine months ended September 30, 2014, the Company incurred cumulative, declared dividends of $14.9 million by issuing approximately 3.3 million shares of common stock. As of September 30, 2014, cumulative, undeclared dividends on the Series A Preferred Stock amounted to approximately $1.7 million.

The Series A Preferred Stock has no maturity date, is not redeemable by the Company at any time, and will remain outstanding unless converted by the holders or mandatorily converted by the Company. Each share of Series A Preferred Stock is convertible, at the holder's option at any time, into approximately 162.4431 shares of common stock of the Company (which is equivalent to a conversion price of approximately $6.16 per share), subject to specified adjustments as set forth in the Series A Designation. Based on the initial conversion rate, approximately 56.0 million shares of common stock of the Company would be issuable upon conversion of all the shares of Series A Preferred Stock. On or after June 6, 2018, the Company may, at its option, give notice of its election to cause all outstanding shares of the Series A Preferred Stock to be automatically converted into shares of common stock of the Company at the conversion rate (as defined in the Series A Designation), if

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. STOCKHOLDERS' EQUITY (Continued)

the closing sale price of the Company's common stock equals or exceeds 150% of the conversion price for at least 20 trading days in a period of 30 consecutive trading days.

If the Company undergoes a fundamental change (as defined in the Series A Designation) and a holder converts its shares of the Series A Preferred Stock at any time beginning at the opening of business on the trading day immediately following the effective date of such fundamental change and ending at the close of business on the 30th trading day immediately following such effective date, the holder will receive, for each share of the Series A Preferred Stock surrendered for conversion, a number of shares of common stock of the Company equal to the greater of: (1) the sum of (i) the conversion rate and (ii) the make-whole premium, if any, as described in the Series A Designation; and (2) the conversion rate which will be increased to equal (i) the sum of the $1,000 liquidation preference plus all accumulated and unpaid dividends to, but excluding, the settlement date for such conversion, divided by (ii) the average of the closing sale prices of the Company's common stock for the five consecutive trading days ending on the third business day prior to such settlement date; provided that the prevailing conversion rate as adjusted pursuant to this will not exceed 292.3977 shares of common stock of the Company per share of the Series A Preferred Stock (subject to adjustment in the same manner as the conversion rate).

Except as required by Delaware law, holders of the Series A Preferred Stock will have no voting rights unless dividends are in arrears and unpaid for six or more quarterly periods. Until such arrearage is paid in full, the holders (voting as a single class with the holders of any other preferred shares having similar voting rights) will be entitled to elect two additional directors and the number of directors on the Company's Board of Directors will increase by that same number.

Common Stock

On May 22, 2014, with stockholder approval, the Company filed a Certificate of Amendment of the Amended and Restated Certificate of Incorporation with the Delaware Secretary of State to increase its authorized common stock by approximately 670.0 million shares for a total of 1.34 billion authorized shares of common stock.

On August 13, 2013, the Company completed the issuance and sale of 43.7 million shares of its common stock in an underwritten public offering. The shares of common stock sold have been registered under the Securities Act pursuant to a Registration Statement on Form S-3 (No. 333-188640), which was filed with the SEC and became automatically effective on May 16, 2013. The net proceeds to the Company from the offering of common stock were approximately $215.2 million, after deducting the underwriting discount and estimated offering expenses. The Company used the net proceeds from the offering to repay a portion of the then outstanding borrowings under its Senior Credit Agreement.

On January 17, 2013, with stockholder approval, the Company filed a Certificate of Amendment of the Amended and Restated Certificate of Incorporation with the Delaware Secretary of State to increase its authorized common stock by approximately 333.3 million shares for a total of 670.0 million authorized shares of common stock.

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. STOCKHOLDERS' EQUITY (Continued)

Warrants

In February 2012, in conjunction with the issuance of the 2017 Notes, the Company issued warrants to purchase 36.7 million shares of the Company's common stock at an exercise price of $4.50 per share of common stock, which the Company refers to as the February 2012 Warrants. The Company allocated $43.6 million to the February 2012 Warrants which is reflected in additional paid-in capital in stockholders' equity, net of $0.6 million in issuance costs. The February 2012 Warrants entitle the holders to exercise the warrants in whole or in part at any time prior to the expiration date of February 8, 2017.

In August 2012, as part of the Company's acquisition of GeoResources by merger, the Company assumed outstanding GeoResources common stock warrants. At the date of the merger 0.6 million GeoResources warrants were outstanding and were converted to 1.2 million Halcón warrants (the August 2012 Warrants). Each GeoResources warrant was converted into an August 2012 Warrant to acquire one share of Halcón common stock (Share Portion) at an exercise price of $8.40 per share of common stock and the right to receive $20 in cash per equivalent assumed share (Cash Portion) at an exercise price of $0.82 per $1.00 received. The August 2012 Warrants contained substantially the same terms of the original GeoResources warrants with adjustments to the exercise price and addition of the Cash Portion to reflect the impact of the consideration per share in the merger. The August 2012 Warrants expired on June 9, 2013. The August 2012 Warrants were reflected as a current liability in the unaudited condensed consolidated balance sheets at March 31, 2013 and were recorded at fair value. Changes in fair value were recognized in "*Interest expense and other, net*" in the unaudited condensed consolidated statements of operations.

Incentive Plan

On May 8, 2006, the Company's stockholders first approved its 2006 Long-Term Incentive Plan (the Plan). On May 23, 2013, shareholders last approved an increase in authorized shares under the Plan from 11.5 million to 41.5 million. As of September 30, 2014 and December 31, 2013, a maximum of 13.7 million and 25.7 million shares of common stock, respectively, remained reserved for issuance under the Plan.

The Company accounts for share-based payment accruals under authoritative guidance on stock compensation, as set forth in ASC Topic 718. The guidance requires all share-based payments to employees and directors, including grants of performance units, stock options, and restricted stock, to be recognized in the financial statements based on their fair values.

For the three and nine months ended September 30, 2014, the Company recognized $4.6 million and $13.8 million, respectively, of share-based compensation expense as a component of "*General and administrative*" on the unaudited condensed consolidated statements of operations. For the three and nine months ended September 30, 2013, the Company recognized $5.0 million and $12.0 million, respectively, of share-based compensation expense.

Performance Share Units

During the three months ended March 31, 2014, the Company granted performance share units (PSU) under the Plan covering 1.6 million shares of common stock to senior management of the Company. The PSU provides that the number of shares of common stock received upon vesting will

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. STOCKHOLDERS' EQUITY (Continued)

vary if the market price of the Company's common stock exceeds certain pre-established target thresholds as measured by the average of the adjusted closing price of a share of the Company's common stock during the sixty trading days preceding the third anniversary of issuance, or the measurement date. The PSU utilizes $4.00 as the floor price, below which the PSU will not vest and will expire. If the average market price at the measurement date is equal to $4.00, the PSU will vest and represent the right to receive 50% of the number of shares of common stock underlying the PSU. At $7.00, the PSU will vest and represent the right to receive the full number of shares of common stock underlying the PSU; and at $10.00, the PSU will vest and represent the right to receive 200% of the number of shares of common stock underlying the PSU. All stock price targets are subject to customary adjustments based upon changes in the Company's capital structure. In the event the average market price falls between targeted price thresholds, the PSU will represent the right to receive a proportionate number of shares, e.g., 75% of the number of shares of common stock underlying the PSU if the average market price at such time is $5.50, 150% of the number of shares of common stock underlying the PSU if the average market price at such time is $8.50, and so forth. The Company has reserved for issuance under the Plan the maximum number of shares that participants might have the right to receive upon vesting of the PSU, or 3.2 million shares of common stock. At September 30, 2014, the Company had $4.0 million of unrecognized compensation expense related to non-vested PSU to be recognized over a weighted-average period of 2.4 years.

Stock Options

During the nine months ended September 30, 2014, the Company granted stock options under the Plan covering 6.2 million shares of common stock to employees of the Company. The stock options have exercise prices ranging from $3.67 to $7.42 with a weighted average exercise price of $3.70. These awards typically vest over a three year period at a rate of one-third on the annual anniversary date of the grant and expire ten years from the grant date. At September 30, 2014, the Company had $13.3 million of unrecognized compensation expense related to non-vested stock options to be recognized over a weighted-average period of 1.1 years.

During the nine months ended September 30, 2013, the Company granted stock options under the Plan covering 6.1 million shares of common stock to employees of the Company. The stock options have exercise prices ranging from $4.43 to $8.23 with a weighted average exercise price of $7.07. These awards typically vest over a three year period at a rate of one-third on the annual anniversary date of the grant and expire ten years from the grant date. At September 30, 2013, the Company had $15.7 million of unrecognized compensation expense related to non-vested stock options to be recognized over a weighted-average period of 1.3 years.

Restricted Stock

During the nine months ended September 30, 2014, the Company granted 3.9 million shares of restricted stock under the Plan to directors and employees of the Company. These restricted shares were granted at prices ranging from $3.67 to $7.42 with a weighted average price of $3.85. Employee shares vest over a three year period at a rate of one-third on the annual anniversary date of the grant, and the non-employee directors' shares vest six-months from the date of grant. At September 30, 2014, the Company had $13.7 million of unrecognized compensation expense related to non-vested restricted stock awards to be recognized over a weighted-average period of 1.2 years.

Table of Contents

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. STOCKHOLDERS' EQUITY (Continued)

During the nine months ended September 30, 2013, the Company granted 3.3 million shares of restricted stock under the Plan to directors and employees of the Company. These restricted shares were granted at prices ranging from $4.43 to $7.65 with a weighted average price of $6.91. Employee shares vest over a three year period at a rate of one-third on the annual anniversary date of the grant, and the non-employee directors' shares vest six- months from the date of grant. At September 30, 2013, the Company had $14.1 million of unrecognized compensation expense related to non-vested restricted stock awards to be recognized over a weighted-average period of 1.3 years.

Treasury Stock

During the nine months ended September 30, 2013, the Company granted 3.3 million shares of restricted stock under the Plan to directors and employees of the Company of which 1.2 million shares were issued out of treasury stock. In addition, the Company retired 0.4 million shares from treasury stock representing shares that were repurchased for taxes tendered upon vesting of stock based compensation awards in prior years. As of September 30, 2013, the Company had no issued shares held in treasury.

11. INCOME TAXES

Under guidance contained in ASC Topic 740, deferred taxes are determined by applying the provisions of enacted tax laws and rates for the jurisdictions in which the Company operates to the estimated future tax effects of the differences between the tax basis of assets and liabilities and their reported amounts in the Company's financial statements. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

In assessing the need for a valuation allowance on the Company's deferred tax assets, the Company considers possible sources of taxable income that may be available to realize the benefit of deferred tax assets, including projected future taxable income, the reversal of existing temporary differences, taxable income in carryback years and available tax planning strategies. The Company considers all available evidence (both positive and negative) in determining whether a valuation allowance is required. A significant item that weighted heavily on the consideration of recoverability of the deferred tax asset was the cumulative three-year book loss driven primarily by ceiling test write-downs in 2013. Based upon the evaluation of the available evidence the Company continued to record a valuation allowance against its net deferred tax assets as of September 30, 2014.

The Company recorded an income tax benefit of $1.3 million on pre-tax income of $55.9 million for the nine months ended September 30, 2014 primarily due to the valuation allowance offset by expected refunds from the filing of certain prior year tax returns during the three months ended September 30, 2014. For the nine months ended September 30, 2013, the Company recorded a tax benefit of $333.9 million on a pre-tax loss of $1.1 billion. The effective tax rate for the nine months ended September 30, 2014 was (2.3)% compared to 29.1% for the nine months ended September 30, 2013. The significant difference in the effective tax rate is primarily due to the valuation allowance that was established during the fourth quarter of 2013 and the expected refunds from the filing of tax returns during the three months ended September 30, 2014.

During the first quarter of 2014, the Internal Revenue Service commenced an audit of GeoResources' tax returns for the tax years ending December 31, 2010 through August 1, 2012. The audit is ongoing as of the date of this filing.

Table of Contents

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. EARNINGS PER COMMON SHARE

The following represents the calculation of earnings (loss) per share (in thousands, except per share amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(In thousands, except per share amounts)			
Basic:				
Net income (loss) available to common stockholders	$ 186,853	$ (859,897)	$ 35,597	$ (818,060)
Weighted average basic number of common shares outstanding	416,470	392,726	415,264	368,696
Basic net income (loss) per share of common stock	$ 0.45	$ (2.19)	$ 0.09	$ (2.22)
Diluted:				
Net income (loss) available to common stockholders	$ 186,853	$ (859,897)	$ 35,597	$ (818,060)
Net income from assumed conversions	9,004			
Net income (loss) available to common stockholders after assumed conversions	$ 195,857	$ (859,897)	$ 35,597	$ (818,060)
Weighted average basic number of common shares outstanding	416,470	392,726	415,264	368,696
Common stock equivalent shares representing shares issuable upon:				
Exercise of stock options	741	Anti-dilutive	452	Anti-dilutive
Exercise of February 2012 Warrants	7,549	Anti-dilutive	5,226	Anti-dilutive
Exercise of August 2012 Warrants				Anti-dilutive
Vesting of restricted shares	2,609	Anti-dilutive	1,608	Anti-dilutive
Vesting of performance units	463		483	
Conversion of 2017 Notes	64,371	Anti-dilutive	Anti-dilutive	Anti-dilutive
Conversion of preferred stock				Anti-dilutive
Conversion of Series A preferred stock	56,043	Anti-dilutive	Anti-dilutive	Anti-dilutive
Weighted average diluted number of common shares outstanding	548,246	392,726	423,033	368,696

Diluted net income (loss) per share of common stock	$	0.36	$	(2.19)	$	0.08	$	(2.22)

Common stock equivalents totaling 9.9 million and 144.2 million shares for the three and nine months ended September 30, 2014, respectively, were not included in the computation of diluted earnings per share of common stock because the effect would have been anti-dilutive. Common stock equivalents totaling 170.9 million and 142.4 million shares for the three and nine months ended

Table of Contents

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. EARNINGS PER COMMON SHARE (Continued)

September 30, 2013, respectively, were not included in the computation of diluted earnings per share of common stock because the effect would have been anti-dilutive due to net losses.

13. ADDITIONAL FINANCIAL STATEMENT INFORMATION

Certain balance sheet amounts are comprised of the following:

	September 30, 2014	December 31, 2013
	(In thousands)	
Accounts receivable:		
Oil, natural gas and natural gas liquids revenues	$ 169,348	$ 129,355
Joint interest accounts	107,383	170,907
Affiliated partnership	46	500
Other	4,805	11,756
	$ 281,582	$ 312,518
Prepaids and other:		
Prepaids	$ 7,484	$ 5,636
Income tax receivable	6,815	10,404
Other	571	58
	$ 14,870	$ 16,098
Accounts payable and accrued liabilities:		
Trade payables	$ 85,121	$ 87,661
Accrued oil and natural gas capital costs	302,874	292,472
Revenues and royalties payable	165,414	124,222
Accrued interest expense	74,871	82,570
Accrued employee compensation	14,879	2,272
Accrued lease operating expenses	24,197	21,469
Drilling advances from partners	29,650	24,882
Affiliated partnership	748	679
Other	316	362
	$ 698,070	$ 636,589

14. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The Company's senior notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by all of the Company's existing 100% owned subsidiaries, other than HK TMS. On June 16, 2014, the Company contributed undeveloped acreage in Mississippi and Louisiana that management believes is prospective for the TMS into HK TMS.

The following condensed consolidating balance sheets, condensed consolidating statements of operations, and condensed consolidating statements of cash flows for the parent company, subsidiary guarantors on a combined basis, the non-guarantor subsidiary, the consolidating adjustments and the total consolidated amounts are presented as of September 30, 2014 and for the three and nine months ended September 30, 2014. Such condensed consolidating financial information may not necessarily be indicative of the financial position, results of operations or cash flows had these subsidiaries operated as independent entities.

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

14. CONDENSED CONSOLIDATING FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

	Three Months Ended September 30, 2014				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
			(In thousands)		
Operating revenues:					
Oil, natural gas and natural gas liquids sales:					
Oil	$	$ 282,644	$ 5,219	$	$ 287,863
Natural gas		8,248			8,248
Natural gas liquids		10,273			10,273
Total oil, natural gas and natural gas liquids sales		301,165	5,219		306,384
Other		125			125
Total operating revenues		301,290	5,219		306,509
Operating expenses:					
Production:					
Lease operating		27,869	225		28,094
Workover and other		5,773			5,773
Taxes other than income	76	28,382	74		28,532
Gathering and other		7,460			7,460
General and administrative	18,591	10,621	1,613	(1,256)	29,569
Depletion, depreciation and accretion	685	132,756	4,161	(2,024)	135,578
Full cost ceiling impairment			20,893	(20,893)	
Total operating expenses	19,352	212,861	26,966	(24,173)	235,006
Income (loss) from operations	(19,352)	88,429	(21,747)	24,173	71,503
Other income (expenses):					
Net gain (loss) on derivative contracts		163,287			163,287
Interest expense and other, net	(79,212)	40,907	(145)		(38,450)
Total other income (expenses)	(79,212)	204,194	(145)		124,837
Income (loss) before income taxes	(98,564)	292,623	(21,892)	24,173	196,340
Income tax benefit (provision)		1,423	482	(610)	1,295
Equity in earnings of subsidiary, net of tax	290,376	(3,671)		(286,705)	

Net income (loss)	191,812	290,375	(21,410)	(263,142)	197,635
Series A preferred dividends	(4,959)				(4,959)
Preferred dividends on redeemable noncontrolling interest			(5,823)		(5,823)
Net income (loss) available to common stockholders	$ 186,853	$ 290,375	$ (27,233)	$ (263,142)	$ 186,853

Table of Contents

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

14. CONDENSED CONSOLIDATING FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

	Nine Months Ended September 30, 2014				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
			(In thousands)		
Operating revenues:					
Oil, natural gas and natural gas liquids sales:					
Oil	$	$ 841,193	$ 6,911	$	$ 848,104
Natural gas		27,965			27,965
Natural gas liquids		28,396			28,396
Total oil, natural gas and natural gas liquids sales		897,554	6,911		904,465
Other		4,337			4,337
Total operating revenues		901,891	6,911		908,802
Operating expenses:					
Production:					
Lease operating		95,349	351		95,700
Workover and other		12,550			12,550
Taxes other than income	228	82,597	177		83,002
Gathering and other		18,119			18,119
Restructuring		987			987
General and administrative	55,850	33,765	3,889	(3,394)	90,110
Depletion, depreciation and accretion	2,038	383,652	4,883	(1,617)	388,956
Full cost ceiling impairment		61,165	20,893	(20,893)	61,165
Other operating property and equipment impairment		3,789			3,789
Total operating expenses	58,116	691,973	30,193	(25,904)	754,378
Income (loss) from operations	(58,116)	209,918	(23,282)	25,904	154,424
Other income (expenses):					
Net gain (loss) on derivative contracts		8,589			8,589
Interest expense and other, net	(237,307)	130,331	(138)		(107,114)
Total other income (expenses)	(237,307)	138,920	(138)		(98,525)
Income (loss) before income taxes	(295,423)	348,838	(23,420)	25,904	55,899

Income tax benefit (provision)		1,295	(80)	80	1,295
Equity in earnings of subsidiary, net of tax	345,898	(4,236)		(341,662)	
Net income (loss)	50,475	345,897	(23,500)	(315,678)	57,194
Series A preferred dividends	(14,878)				(14,878)
Preferred dividends on redeemable noncontrolling interest			(6,719)		(6,719)
Net income (loss) available to common stockholders	$ 35,597	$ 345,897	$ (30,219)	$ (315,678)	$ 35,597

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

14. CONDENSED CONSOLIDATING FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING BALANCE SHEETS

	September 30, 2014				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
	(In thousands)				
Current assets:					
Cash	$	$ 112	$ 94,576	$	$ 94,688
Accounts receivable		265,751	15,936	(105)	281,582
Receivables from derivative contracts		19,715			19,715
Restricted cash			15,984		15,984
Inventory		6,108	2		6,110
Prepaids and other	830	14,040			14,870
Total current assets	830	305,726	126,498	(105)	432,949
Oil and natural gas properties (full cost method):					
Evaluated		5,564,223	69,395	(2,788)	5,630,830
Unevaluated		1,885,704	373,395		2,259,099
Gross oil and natural gas properties		7,449,927	442,790	(2,788)	7,889,929
Less accumulated depletion		(2,628,502)	(25,841)	22,511	(2,631,832)
Net oil and natural gas properties		4,821,425	416,949	19,723	5,258,097
Other operating property and equipment:					
Gas gathering and other operating assets	14,434	143,132	137		157,703
Less accumulated depreciation	(5,913)	(7,978)	(7)		(13,898)
Net other operating property and equipment	8,521	135,154	130		143,805
Other noncurrent assets:					
Receivables from derivative contracts		24,144			24,144
Debt issuance costs, net	58,037				58,037
Deferred income taxes	1,807	9,876			11,683
Intercompany notes and accounts receivable	4,748,375	219,154		(4,967,529)	
Investment in subsidiary	453,899	391,969		(845,868)	
Equity in oil and natural gas partnership		4,472			4,472
Funds in escrow and other	516	709			1,225
Total assets	$ 5,271,985	$ 5,912,629	$ 543,577	$ (5,793,779)	$ 5,934,412

Current liabilities:									
Accounts payable and accrued liabilities	$		$	643,349	$	54,906	$	(185)	$ 698,070
Liabilities from derivative contracts				1,208					1,208
Asset retirement obligations				218					218
Current portion of deferred income taxes		1,807		9,876					11,683
Current portion of long-term debt				694					694
Total current liabilities		1,807		655,345		54,906		(185)	711,873
Long-term debt		3,533,158							3,533,158
Other noncurrent liabilities:									
Liabilities from derivative contracts				17,629					17,629
Asset retirement obligations				35,440		237			35,677
Intercompany notes and accounts payable		219,154		4,748,375				(4,967,529)	
Other				1,941		5,560			7,501
Commitments and contingencies									
Mezzanine equity:									
Redeemable noncontrolling interest						110,708			110,708
Stockholders' equity:									
Preferred stock									
Common stock		41							41
Additional paid-in capital		2,988,445				402,385		(402,385)	2,988,445
Retained earnings (accumulated deficit)		(1,470,620)		453,899		(30,219)		(423,680)	(1,470,620)
Total stockholders' equity		1,517,866		453,899		372,166		(826,065)	1,517,866
Total liabilities and stockholders' equity	$	5,271,985	$	5,912,629	$	543,577	$	(5,793,779)	$ 5,934,412

Table of Contents

HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

14. CONDENSED CONSOLIDATING FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30, 2014				
	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
			(In thousands)		
Cash flows from operating activities:					
Net cash provided by (used in) operating activities	$ (277,458)	$ 859,079	$ 3,057	$ (2,788)	$ 581,890
Cash flows from investing activities:					
Oil and natural gas capital expenditures		(1,116,504)	(64,933)	2,788	(1,178,649)
Proceeds received from sale of oil and natural gas assets		446,197	33,777		479,974
Advance on carried interest		(62,500)	(126,942)		(189,442)
Other operating property and equipment capital expenditures	(1,050)	(39,259)	(47)		(40,356)
Advances to subsidiary	(63,183)	(154,138)		217,321	
Funds held in escrow and other		1,221			1,221
Net cash provided by (used in) investing activities	(64,233)	(924,983)	(158,145)	220,109	(927,252)
Cash flows from financing activities:					
Proceeds from borrowings	1,744,000				1,744,000
Repayments of borrowings	(1,399,000)				(1,399,000)
Debt issuance costs	(757)				(757)
HK TMS, LLC preferred stock issued			110,051		110,051
HK TMS, LLC tranche rights			4,516		4,516
Preferred dividends on redeemable noncontrolling interest			(3,518)		(3,518)
Restricted cash			(15,984)		(15,984)
Proceeds from subsidiary		63,183	154,138	(217,321)	
Offering costs and other	(2,553)		461		(2,092)
Net cash provided by (used in) financing activities	341,690	63,183	249,664	(217,321)	437,216
Net increase (decrease) in cash	(1)	(2,721)	94,576		91,854
Cash at beginning of period	1	2,833			2,834
Cash at end of period	$	$ 112	$ 94,576	$	$ 94,688

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

The following discussion is intended to assist in understanding our results of operations for the three and nine months ended September 30, 2014 and 2013 should be read in conjunction with our unaudited condensed consolidated financial statements and the notes thereto included in this Quarterly Report on Form 10-Q and with the consolidated financial statements, notes and management's discussion and analysis of financial condition and results of operations included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2013.

Statements in this discussion may be forward-looking. These forward-looking statements involve risks and uncertainties, including those discussed below, which could cause actual results to differ from those expressed. For more information, see *"Special note regarding forward-looking statements."*

Overview

We are an independent energy company focused on the acquisition, production, exploration and development of onshore liquids-rich oil and natural gas assets in the United States. We were incorporated in Delaware on February 5, 2004 and were recapitalized on February 8, 2012. During 2012, we focused our efforts on the acquisition of unevaluated leasehold and producing properties in selected prospect areas, providing us with an extensive drilling inventory in multiple basins that we believe allow for multiple years of production growth and broad flexibility to direct our capital resources to projects with the greatest potential returns. During 2013 and 2014, we focused on the development of acquired properties and also divested non-core assets in order to fund activities in our core resource plays. Additionally, in 2014, we began the development of certain assets we believe are prospective for the Tuscaloosa Marine Shale (TMS).

Our oil and natural gas assets consist of undeveloped acreage positions in unconventional liquids-rich basins/fields. We have acquired acreage and may acquire additional acreage in the Bakken / Three Forks formations in North Dakota, the Eagle Ford formation in East Texas and the TMS formation in Louisiana and Mississippi, as well as other areas.

Our average daily oil and natural gas production increased 31% in the first nine months of 2014 compared to the same period in the prior year. During the first nine months of 2014, production averaged 40,769 barrels of oil equivalent (Boe) per day (Boe/d) compared to average daily production of 31,007 Boe/d during the first nine months of 2013. The increase in production compared to the prior year period was driven primarily by operated drilling results and increased production volumes associated with the development of properties we have acquired in the Bakken / Three Forks and the Eagle Ford formation in East Texas (which we refer to as "El Halcón"). These areas collectively accounted for an increase of approximately 17,000 Boe/d. This increase was partially offset by production decreases from our divestiture of non-core properties during 2013 and 2014. During the first nine months of 2014, we participated in the drilling of 230 gross (80.9 net) wells, all of which were completed and capable of production.

Recent Developments

Amendments to the Senior Credit Agreement and Borrowing Base

On September 30, 2014, we entered into the Eighth Amendment to our Senior Credit Agreement (the Eighth Amendment). The Eighth Amendment increased the borrowing base under our Senior Credit Agreement to $1.05 billion. On March 21, 2014, we entered into the Seventh Amendment to our Senior Credit Agreement (the Seventh Amendment). The Seventh Amendment provided us additional flexibility under the interest coverage test by modifying the minimum Interest Coverage Ratio to be 2.0 to 1.0 for any fiscal quarter ending on or before December 31, 2014.

HK TMS, LLC Preferred Stock Issuance

On June 16, 2014, we entered into a transaction with funds and accounts managed by affiliates of Apollo Global Management, LLC (Apollo) pursuant to which HK TMS, LLC (HK TMS), which holds our acreage in Mississippi and Louisiana that we believe is prospective for the TMS, sold 150,000 preferred shares in exchange for $150 million and the right to overriding royalty interests in future wells. HK TMS does not participate in our Senior Credit Agreement and is not a guarantor of any of our senior notes.

Divestiture of East Texas Assets

On May 9, 2014, we completed the divestiture of certain non-core assets in East Texas (the East Texas Assets) to a privately-owned company for a total purchase price of $426.3 million after closing adjustments for (i) operating expenses, capital expenditures and revenues between the effective date and the closing date, (ii) title and environmental defects, and (iii) other purchase price adjustments customary in oil and gas purchase and sale agreements. The effective date of the transaction was April 1, 2014. Proceeds from the sale were recorded as a reduction to the carrying value our full cost pool with no gain or loss recorded.

Capital Resources and Liquidity

Our near-term capital spending requirements are expected to be funded with cash flows from operations, proceeds from potential non-core asset divestitures, proceeds from potential capital market transactions and borrowings under our Senior Credit Agreement, which has a current borrowing base of $1.05 billion. Our borrowing base is redetermined on a semi-annual basis (with us and the lenders each having the right to one interim unscheduled redetermination between any two consecutive semi-annual redeterminations) and adjusted based on the estimated value of our oil and natural gas reserves, the amount and cost of our other indebtedness and other relevant factors. Our ability to utilize the full amount of our borrowing capacity is influenced by a variety of factors, including redeterminations of our borrowing base and covenants under our Senior Credit Agreement and our senior unsecured debt indentures. Our Senior Credit Agreement contains customary financial and other covenants, including minimum working capital levels (the ratio of current assets plus the unused commitment under the Senior Credit Agreement to current liabilities) of not less than 1.0 to 1.0 and minimum coverage of interest expenses (as defined in the Senior Credit Agreement) of i) not less than 2.0 to 1.0 through December 31, 2014 (pursuant to the Seventh Amendment), and ii) not less than 2.5 to 1.0 for subsequent periods. We are subject to additional covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. Additionally, the indentures governing our senior unsecured debt contain covenants limiting our ability to incur additional indebtedness, including borrowings under our Senior Credit Agreement, unless we meet one of two alternative tests. The first test, the fixed charge coverage ratio test, applies to all indebtedness and requires that after giving effect to the incurrence of additional debt the ratio of our adjusted consolidated EBITDA (as defined in our indentures) to our adjusted consolidated interest expense over the trailing four fiscal quarters will be at least 2.0 to 1.0. The second test allows us to incur additional indebtedness, beyond the limitations of the fixed charge coverage ratio test, as long as this additional debt is incurred under Credit Facilities (as defined in our indentures) and the amount of such additional indebtedness is not more than the greater of a fixed sum of $750 million or 30% of our adjusted consolidated net tangible assets (as defined in all of our indentures), which is determined primarily by the value of discounted future net revenues from proved oil and natural gas reserves as of the date of such determination. At September 30, 2014, we had $345.0 million indebtedness outstanding under our Senior Credit Agreement, $1.1 million of letters of credit outstanding and approximately $703.9 million of borrowing capacity available under our Senior Credit Agreement.

Table of Contents

Our ability to meet our debt covenants and our capacity to incur additional indebtedness will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. For example, lower oil and natural gas prices could result in a redetermination of the borrowing base under our Senior Credit Agreement at a lower level and reduce our adjusted consolidated EBITDA, as well as our adjusted consolidated net tangible assets as determined under our indentures, and thus could reduce our ability to incur indebtedness. Our strategic divestitures of non-core producing properties in favor of investing in undeveloped acreage, coupled with our aggressive drilling plans also impact our near-term ability to comply with our debt covenants, particularly the interest coverage test under our Senior Credit Agreement and the fixed charge coverage ratio under our indentures by reducing our production and reserves on a current and, for purposes of covenant calculations, a pro forma historical basis, while drilling takes time to replace these losses. Of course, over the longer term, we expect that our strategy and our investments will result in increased production and reserves, lower lease operating costs and more abundant drilling opportunities. As a consequence, we constantly monitor our liquidity and capital resources, endeavor to anticipate potential covenant compliance issues and work with the lenders under our Senior Credit Agreement to address any such issues ahead of time.

We have in the past obtained amendments to the covenants under our Senior Credit Agreement under circumstances where we anticipated that it might be challenging for us to comply with our financial covenants for a particular period of time. During 2013, we obtained amendments to the calculation of the interest coverage ratio covenant under our Senior Credit Agreement allowing us to annualize our quarterly EBITDA because, among other things, we anticipated that our strategic decision to divest various non-core producing properties and invest in the acquisition and drilling of undeveloped acreage would have caused us to fall below the interest coverage ratio. We requested a reduction in the minimum required interest coverage ratio of 2.0 to 1.0 for 2014 and that request was granted on March 21, 2014. The basis for the amendment request is similar to previously requested waivers described above, i.e., the potential for us to fall out of compliance primarily as a result of our strategic decision to divest producing properties, invest extensively in undeveloped acreage and the long lead times associated with replacing lost production through our drilling program. As part of our plan to manage liquidity risks, we have scaled back our capital expenditures budget, focused our drilling program on our highest return projects, entered into a transaction with funds and accounts managed by affiliates of Apollo Global Management, LLC, to finance the development of our TMS assets, and we continue to explore opportunities to divest non-core properties.

If, in the future, the lenders under our Senior Credit Agreement are unwilling to provide us with the covenant flexibility we seek, and we are unable to comply with those covenants, we may be forced to repay or refinance amounts then outstanding under the Senior Credit Agreement and seek alternative sources of capital to fund our business and anticipated capital expenditures. In the event that we are unable to access sufficient capital to fund our business and planned capital expenditures, we may be required to curtail our drilling, development, land acquisition and other activities, which could result in a decrease in our production of oil and natural gas, may be subject to forfeitures of leasehold interests to the extent we are unable or unwilling to renew them, and may be forced to sell some of our assets on an untimely or unfavorable basis, each of which could adversely affect our results of operations and financial condition. Further, the failure to comply with the restrictive covenants relating to our indebtedness could result in the declaration of a default and cross default under the instruments governing our indebtedness, potentially resulting in acceleration of our obligations and adversely impacting our financial condition.

Our future capital resources and liquidity depend, in part, on our success in developing our leasehold interests, growing reserves and production and finding additional reserves. Cash is required to fund capital expenditures necessary to offset inherent declines in our production and proven reserves, which is typical in the capital-intensive oil and natural gas industry. We therefore continuously monitor

Table of Contents

our liquidity and the capital markets and evaluate our development plans in light of a variety of factors, including, but not limited to, our cash flows, capital resources, acquisition opportunities and drilling success.

We strive to maintain financial flexibility while pursuing our drilling plans and evaluating potential acquisitions, and will therefore likely continue to access capital markets (if on acceptable terms) as necessary to, among other things, maintain substantial borrowing capacity under our Senior Credit Agreement, facilitate drilling on our large undeveloped acreage position and permit us to selectively expand our acreage position and infrastructure projects while sustaining sufficient operating cash levels. Our ability to complete future debt and equity offerings and maintain or increase our borrowing base is subject to a number of variables, including our level of oil and natural gas production, reserves and commodity prices, as well as various economic and market conditions that have historically affected the oil and natural gas industry. Prices for oil and natural gas have historically been subject to seasonal fluctuations characterized by peak demand and higher prices in the winter heating season; however, the impact of other risks and uncertainties have influenced prices throughout recent years. Even if we are otherwise successful in growing our reserves and production, if oil and natural gas prices decline for a sustained period of time, our ability to fund our capital expenditures, complete acquisitions, reduce debt, meet our financial obligations and become profitable may be materially impacted.

Cash Flow

Our primary sources of cash for the nine months ended September 30, 2014 were from operating and financing activities and for the nine months ended September 30, 2013 were from financing activities. In the first nine months of 2014, cash generated by operating and financing activities was used to fund our drilling program and acquire additional leasehold interests. Cash provided by financing activities was attributable to net borrowings on our Senior Credit Agreement and the sale of HK TMS preferred stock to Apollo. See *"Results of Operations"* for a review of the impact of prices and volumes on sales.

Net increase (decrease) in cash is summarized as follows:

	Nine Months Ended September 30,	
	2014	**2013**
	(In thousands)	
Cash flows provided by (used in) operating activities	$ 581,890	$ 391,605
Cash flows provided by (used in) investing activities	(927,252)	(1,826,500)
Cash flows provided by (used in) financing activities	437,216	1,432,850
Net increase (decrease) in cash	$ 91,854	$ (2,045)

Operating Activities. Net cash provided by operating activities for the nine months ended September 30, 2014 and 2013, was $581.9 million and $391.6 million, respectively.

The $581.9 million of operating cash flows for the nine months ended September 30, 2014 primarily reflect the impact of increased production from our developmental drilling activities which drove an increase in revenues, as compared to the prior year period, and outpaced related operating expenses. Increased revenues were driven by the increase in production volumes from our Bakken / Three Forks and El Halcón areas.

Investing Activities. The primary driver of cash used in investing activities is capital spending, specifically drilling and completions coupled with the acquisition of unevaluated leasehold acreage in our target areas. Net cash used in investing activities was approximately $927.3 million and $1.8 billion for the nine months ended September 30, 2014 and 2013, respectively.

Table of Contents

During the first nine months of 2014, we incurred cash expenditures of $1.2 billion on oil and natural gas capital expenditures, of which $906.5 million related to drilling and completion costs and the remainder was primarily associated with leasing, acquisitions and seismic data. We participated in the drilling of 230 gross (80.9 net) wells, all of which were completed and capable of production. These expenditures were offset by $480.0 million in proceeds received from the divestitures of various non-core assets, including the East Texas Assets. As part of HK TMS's transaction with Apollo, discussed in further detail below, as well as in Item 1. *Condensed Consolidated Financial Statements (Unaudited)* Note 9,*"Mezzanine Equity,"* we received proceeds of approximately $33.8 million from the conveyance of an overriding royalty interest to Apollo.

On December 20, 2013, we entered into a carry and earning agreement, as amended with an independent third party (seller) associated with the acquisition of certain properties believed to be prospective for the TMS, primarily in Wilkinson County, Mississippi and in West Feliciana and East Feliciana Parishes, Louisiana. The agreement required us to fund up to $189.4 million in exchange for approximately 117,870 net acres. We paid $62.5 million of the carry amount at closing on February 28, 2014 and the remaining $126.9 million during the three months ended June 30, 2014, reflected as *"Advance on carried interest"* in the accompanying unaudited condensed consolidating statements of cash flows. The carry amount is to be used by the seller to fund wells prospective for the TMS to be drilled by the seller on the seller's retained acreage. As part of the transaction, we will also receive a 5% working interest in the carry wells. Any portion of the carry amount not spent by the seller, in accordance with the agreement, on or before August 31, 2017, will be returned to us.

During the first nine months of 2014, we spent an additional $40.4 million on other operating property and equipment capital expenditures, of which $29.6 million pertained to pipelines and related infrastructure projects, and a majority of the remainder was spent on leasehold improvements.

During the first nine months of 2013, we incurred $1.8 billion on oil and natural gas capital expenditures. We participated in the drilling of 213 gross (87.6 net) wells of which 210 gross (84.6 net) wells were completed and capable of production, and 3 gross (3.0 net) wells were dry holes. We spent an additional $120.1 million on other operating property and equipment capital expenditures, of which $104.5 million pertained to pipelines and related infrastructure projects, and the remainder was spent on leasehold improvements, the purchase of an aircraft and automobiles, and computers and software primarily in our corporate office in Houston, Texas. Proceeds from sales of oil and gas properties were approximately $160.3 million primarily attributable to the July 2013 sale of Eagle Ford Shale assets located in Fayette and Gonzales Counties, Texas.

Financing Activities. Net cash flows provided by financing activities were $437.2 million and $1.4 billion for the nine months ended September 30, 2014 and 2013, respectively. The primary drivers of cash provided by financing activities for the nine months ended September 30, 2014 were net borrowings on our Senior Credit Agreement. In addition, on June 16, 2014, HK TMS entered into a transaction with Apollo by selling 150,000 preferred shares in HK TMS, which holds all of our acreage in Mississippi and Louisiana believed to be prospective for the TMS. Apollo contributed $150 million to HK TMS and we contributed all our assets related to the TMS as well as $50 million in cash. The proceeds from Apollo were allocated to the components of the transaction, resulting in approximately $110.1 million of proceeds associated with the issuance of HK TMS preferred stock and approximately $4.5 million associated with Apollo's rights to additional preferred shares within cash flows from financing activities and the aforementioned $33.8 million investing cash flows related to the overriding royalty conveyance. The proceeds are being used to develop the TMS.

On August 13, 2013, we completed the issuance of $400 million aggregate principal amount of our 2022 Notes. The net proceeds to us from the offering were approximately $392.1 million after deducting commissions and offering expenses and were used to repay a portion of the then outstanding borrowings under our Senior Credit Agreement.

Table of Contents

On August 13, 2013, we also completed our offering of 43.7 million shares of common stock in an underwritten public offering. The net proceeds from the offering of our common stock were approximately $215.2 million, after deducting the underwriting discount and estimated offering expenses. We used the net proceeds from the offering to repay a portion of the then outstanding borrowings on our Senior Credit Agreement.

On June 18, 2013, we completed our offering of 345,000 shares of the Series A Preferred Stock at a public offering price of $1,000 per share. The net proceeds to us from the offering of the Series A Preferred Stock were approximately $335.2 million, after deducting the underwriting discount and offering expenses. We used the net proceeds from the offering to repay a portion of the then outstanding borrowings under our Senior Credit Agreement.

On January 14, 2013, we completed the issuance of an additional $600.0 million aggregate principal amount of our 2021 Notes at a price to the initial purchasers of 105% of par. The net proceeds from the sale of the additional 2021 Notes were approximately $619.5 million (after deducting offering fees and expenses) and were used to repay all of the then outstanding borrowings under our Senior Credit Agreement and for general corporate purposes, including funding a portion of our 2013 capital expenditures program.

Contractual Obligations

We lease corporate office space in Houston, Texas; Tulsa, Oklahoma; and Denver, Colorado as well as a number of other field office locations. Rent expense was approximately $6.0 million and $6.8 million for the nine months ended September 30, 2014 and 2013, respectively. In addition, we have commitments for certain equipment under long-term operating lease agreements, namely drilling rigs as well as pipeline and well equipment, with various expiration dates through 2018. Early termination of the drilling rig commitments would result in termination penalties approximating $63.7 million, which would be in lieu of the remaining $109.9 million of drilling rig commitments as of September 30, 2014. As of September 30, 2014, the amount of commitments under office and equipment lease agreements is consistent with the levels at December 31, 2013 disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2013, approximating $62.2 million in the aggregate, and containing various expiration dates through 2024.

We have entered into various long-term gathering, transportation and sales contracts in the Bakken / Three Forks formations in North Dakota. As of September 30, 2014, we had in place nine long-term crude oil contracts and two long-term natural gas contracts in this area. Under the terms of these contracts, we have committed a substantial portion of our Bakken / Three Forks production for periods ranging from five to ten years from the date of first production. The sales prices under these contracts are based on posted market rates. We believe that there are sufficient available reserves and supplies in the Bakken / Three Forks formations to meet our commitments. Historically, we have been able to meet our delivery commitments.

On December 20, 2013, we entered into a carry and earning agreement associated with the acquisition of certain properties believed to be prospective for the TMS, primarily in Wilkinson County, Mississippi and in West Feliciana and East Feliciana Parishes, Louisiana. The agreement required us to fund up to $189.4 million in exchange for approximately 117,870 net acres. We paid $62.5 million of the carry amount at closing on February 28, 2014 and the remaining $126.9 million during the three months ended June 30, 2014, reflected as *"Advance on carried interest"* in the accompanying unaudited condensed consolidating statements of cash flows. The carry amount is to be used by the seller to fund wells prospective for the TMS to be drilled by the seller on the seller's retained acreage. As part of the transaction, we will also receive a 5% working interest in the carry wells. Any portion of the carry amount not spent by the seller, in accordance with the Agreement, on or before August 31, 2017, will be returned to us.

Table of Contents

On June 16, 2014, we entered into a transaction to develop our TMS assets with funds and accounts managed by affiliates of Apollo Global Management, LLC. See Item 1. *Condensed Consolidated Financial Statements (Unaudited)* Note 9, "*Mezzanine Equity,"* for a discussion of the drilling obligation associated with the transaction.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon the unaudited condensed consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. Preparation of these unaudited condensed consolidated financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. There have been no material changes to our critical accounting policies from those described in our Annual Report on Form 10-K for the fiscal year ended December 31, 2013.

Table of Contents

Results of Operations

Three Months Ended September 30, 2014 and 2013

We reported net income of $197.6 million for the three months ended September 30, 2014 compared to a net loss of $854.8 million for the three months ended September 30, 2013. The following table summarizes key items of comparison and their related change for the periods indicated.

In thousands (except per unit and per Boe amounts)	Three Months Ended September 30, 2014	2013	Change
Net income (loss)	$ 197,635	$ (854,827)	$ 1,052,462
Operating revenues:			
Oil	287,863	288,850	(987)
Natural gas	8,248	7,457	791
Natural gas liquids	10,273	7,894	2,379
Other	125	806	(681)
Operating expenses:			
Production:			
Lease operating	28,094	37,539	(9,445)
Workover and other	5,773	2,029	3,744
Taxes other than income	28,532	26,613	1,919
Gathering and other	7,460	3,766	3,694
General and administrative:			
General and administrative	24,978	28,743	(3,765)
Share-based compensation	4,591	5,019	(428)
Depletion, depreciation and accretion:			
Depletion Full cost	132,968	139,852	(6,884)
Depreciation Other	2,183	2,236	(53)
Accretion expense	427	1,003	(576)
Full cost ceiling impairment		909,098	(909,098)
Other operating property and equipment impairment		67,254	(67,254)
Goodwill impairment		228,875	(228,875)
Other income (expenses):			
Net gain (loss) on derivative contracts	163,287	(54,427)	217,714
Interest expense and other, net	(38,450)	(13,663)	(24,787)
Income tax (provision) benefit	1,295	360,283	(358,988)
Production:			
Oil MBbls	3,301	2,885	416
Natural Gas Mmcf	2,398	2,195	203
Natural gas liquids MBbls	306	218	88
Total MBoe*(1)*	4,007	3,469	538
Average daily production Boe*(1)*	43,554	37,707	5,847
Average price per unit*(2)*:			
Oil price Bbl	$ 87.20	$ 100.12	$ (12.92)
Natural gas price Mcf	3.44	3.40	0.04
Natural gas liquids price Bbl	33.57	36.21	(2.64)
Total per Boe*(1)*	76.46	87.69	(11.23)
Average cost per Boe:			
Production:			
Lease operating	$ 7.01	$ 10.82	$ (3.81)
Workover and other	1.44	0.58	0.86
Taxes other than income	7.12	7.67	(0.55)
Gathering and other	1.86	1.09	0.77
General and administrative:			
General and administrative	6.23	8.29	(2.06)
Share-based compensation	1.15	1.45	(0.30)
Depletion	33.18	40.31	(7.13)

(1)

Natural gas reserves are converted to oil reserves using a ratio of six Mcf to one Bbl of oil. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.

(2) *Amounts exclude the impact of cash paid/received on settled contracts as we did not elect to apply hedge accounting.*

For the three months ended September 30, 2014, oil, natural gas and natural gas liquids revenues were largely inline with the same period in 2013 as the impact of increased production volumes associated with the development of properties in our Bakken / Three Forks and El Halcón areas was largely offset by a decrease in realized average prices per Boe, which decreased $11.23 per Boe to $76.46 per Boe. These areas collectively accounted for an increase of approximately 14,400 Boe/d and $72.7 million of incremental revenues.

Lease operating expenses decreased $9.4 million for the three months ended September 30, 2014, primarily due to our divestiture of non-core properties in 2013 and 2014 which, historically, had higher operating costs. This decrease was partially offset by costs incurred in our core areas and the increase in relative production within these areas as we continue to carry out our development plan. Lease operating expenses were $7.01 per Boe for the three months ended September 30, 2014, compared to $10.82 per Boe for the same period in 2013. The decrease in lease operating expenses per Boe primarily results from the increase in our production and efforts to reduce costs and become more efficient operating since the comparable 2013 period.

Workover expenses increased $3.7 million for the three months ended September 30, 2014 compared to the same period in 2013 primarily due to $3.4 million of expenses associated with our core areas and an increase in activity in these areas.

Taxes other than income increased $1.9 million for the three months ended September 30, 2014 as compared to the same period in 2013 primarily due to $7.2 million of taxes associated with increased production attributable to acquired properties as we continue to carry out our development plan. The increase was partially offset by a decrease in production associated with non-core properties we divested in 2013 and 2014. Most production taxes are based on realized prices at the wellhead. As revenues or volumes from oil and natural gas sales increase or decrease, production taxes on these sales also increase or decrease. On a per unit basis, taxes other than income were $7.12 per Boe and $7.67 per Boe for the three months ended September 30, 2014 and 2013, respectively.

Gathering and other expenses for the three months ended September 30, 2014 and 2013 were $7.5 million and $3.8 million, respectively. The $7.5 million of expenses incurred for the three months ended September 30, 2014 primarily relate to gathering and other fees paid on our oil and natural gas production, which has increased 16% compared to the prior year period.

General and administrative expense for the three months ended September 30, 2014 decreased $3.8 million to $25.0 million as compared to the same period in 2013. The decrease in general and administrative expenses results from decreases in professional fees amounting to $3.7 million. On a per unit basis, general and administrative expenses were $6.23 per Boe and $8.29 per Boe, for the three months ended September 30, 2014 and 2013, respectively.

Share-based compensation expense for the three months ended September 30, 2014 was $4.6 million, a decrease of $0.4 million compared to the same period in 2013. The decrease results from lower fair market values for new awards granted to employees and directors subsequent to the comparable prior year period.

Depletion for oil and natural gas properties is calculated using the unit of production method, which depletes the capitalized costs of evaluated properties plus future development costs based on the ratio of production for the current period to total reserve volumes of evaluated properties as of the beginning of the period. Depletion expense decreased $6.9 million to $133.0 million for the three months ended September 30, 2014 compared to the same period in 2013. On a per unit basis, depletion expense was $33.18 per Boe for the three months ended September 30, 2014 compared to $40.31 per Boe for the three months ended September 30, 2013. The decrease in the depletion rate per Boe is partially attributable to decreases in the amortizable base due to the full cost ceiling test impairments since the prior year period.

Accretion expense is a function of changes in the present value of our asset retirement obligations from period to period. We recorded accretion expense of $0.4 million for the three months ended September 30, 2014 and $1.0 million for the same period in 2013. The decrease in accretion expense is attributable to our divestiture of non-core properties and associated asset retirement obligations in 2013 and 2014.

We utilize the full cost method of accounting to account for our oil and natural gas exploration and development activities. Under this method of accounting, we are required on a quarterly basis to determine whether the book value of our oil and natural gas properties (excluding unevaluated properties) is less than or equal to the "ceiling", based upon the expected after tax present value (discounted at 10%) of the future net cash flows from our proved reserves. Any excess of the net book value of our oil and natural gas properties over the ceiling must be recognized as a non-cash impairment expense. Our net book value of oil and natural gas properties at September 30, 2014 did not exceed the ceiling amount. At September 30, 2013, our costs exceeded our ceiling limitation by $909.1 million, resulting in a write-down of our oil and natural gas properties before income taxes. During the three months ended September 30, 2013, we transferred $655.7 million of unevaluated property costs to the full cost pool primarily related to Woodbine assets in East Texas where capital was reallocated to El Halcón, and certain Utica/Point Pleasant assets in Northwest Pennsylvania related to non-economical drilling results obtained in the third quarter of 2013. The combined impact of less favorable oil price differentials adversely affecting proved reserve values and the aforementioned transfers of unevaluated properties to the full cost pool contributed to the ceiling impairment. Changes in production rates, levels of reserves, future development costs, transfers of unevaluated properties, commodity prices, and other factors will determine our actual ceiling test calculation and impairment analyses in future periods.

We review our gas gathering systems and equipment and other operating assets for impairment in accordance with ASC 360. For the three months ended September 30, 2013, we recorded a non-cash impairment charge of $67.3 million. The impairment relates to our gross investments of $68.3 million in gas gathering infrastructure that will not be economically recoverable due to our shift in exploration, drilling and developmental plans from the Woodbine area to El Halcón during the third quarter of 2013.

During the third quarter of 2013, we performed our annual goodwill impairment test, and based on this review; we recorded a non-cash impairment charge of $228.9 million to reduce the carrying value of goodwill to zero. In the first step of the goodwill impairment test, we determined that the fair value of our reporting unit was less than the carrying amount, including goodwill, primarily due to pricing deterioration in the NYMEX forward pricing curve coupled with less favorable oil price differentials in our core areas, both factors which adversely impacted the fair value of our proved reserves. Therefore, we performed the second step of the goodwill impairment test, which led us to conclude that there would be no remaining implied fair value attributable to goodwill.

We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil and natural gas production. Consistent with prior years, we have elected not to designate any positions as cash flow hedges for accounting purposes, and accordingly, we record the net change in the mark-to-market value of these derivative contracts in our unaudited condensed consolidated statements of operations. At September 30, 2014, we had a $43.9 million derivative asset, $19.7 million of which was classified as current, and we had a $18.8 million derivative liability, $1.2 million of which was classified as current associated with these contracts. We recorded a net derivative gain of $163.3 million ($169.7 million net unrealized gain and $6.4 million net realized loss on settled contracts and premium costs) for the three months ended September 30, 2014 compared to a net derivative loss of $54.4 million ($38.1 million net unrealized loss and $16.3 million net realized loss on settled contracts and premium costs), in the same period in 2013.

Table of Contents

Interest expense increased $24.8 million for the three months ended September 30, 2014 from the same period in 2013. Capitalized interest for the three months ended September 30, 2014 and 2013 was $40.4 million and $53.2 million, respectively. The decrease in capitalized interest was driven by decreases in our unevaluated properties since September 30, 2013, which is the basis of our capitalized interest calculation. Interest expense subject to capitalization increased to $79.2 million in the three months ended September 30, 2014 from $67.4 million in the comparable prior year period. The increase in interest subject to capitalization is attributed to the issuance of the additional 2020 Notes subsequent to September 30, 2013.

We recorded an income tax benefit of $1.3 million for the three months ended September 30, 2014 due to an offsetting valuation allowance and expected tax refunds, as discussed further in Item 1. *Condensed Consolidated Financial Statements (Unaudited)* Note 11,*"Income Taxes,"* compared to an income tax benefit of $360.3 million due to our pre-tax loss of $1.2 billion in the comparable prior year period. The effective tax rate for the three months ended September 30, 2014 was (0.7)% compared to 29.7% for the three months ended September 30, 2013. The change in effective tax rate is due to the valuation allowance recorded against our net deferred tax assets as of September 30, 2014 and expected refunds from the filing of tax returns during the three months ended September 30, 2014.

Table of Contents

Nine Months Ended September 30, 2014 and 2013

We reported net income of $57.2 million and a net loss of $812.3 million for the nine months ended September 30, 2014 and 2013, respectively. The following table summarizes key items of comparison and their related change for the periods indicated.

In thousands (except per unit and per Boe amounts)	Nine Months Ended September 30, 2014	2013	Change
Net income (loss)	$ 57,194	$ (812,274)	$ 869,468
Operating revenues:			
Oil	848,104	672,167	175,937
Natural gas	27,965	19,971	7,994
Natural gas liquids	28,396	15,976	12,420
Other	4,337	2,090	2,247
Operating expenses:			
Production:			
Lease operating	95,700	94,676	1,024
Workover and other	12,550	4,276	8,274
Taxes other than income	83,002	62,616	20,386
Gathering and other	18,119	6,901	11,218
Restructuring	987	507	480
General and administrative:			
General and administrative	76,273	86,891	(10,618)
Share-based compensation	13,837	11,994	1,843
Depletion, depreciation and accretion:			
Depletion Full cost	381,152	312,658	68,494
Depreciation Other	6,429	4,778	1,651
Accretion expense	1,375	2,828	(1,453)
Full cost ceiling impairment	61,165	909,098	(847,933)
Other operating property and equipment impairment	3,789	67,254	(63,465)
Goodwill impairment		228,875	(228,875)
Other income (expenses):			
Net gain (loss) on derivative contracts	8,589	(38,749)	47,338
Interest expense and other, net	(107,114)	(24,245)	(82,869)
Income tax (provision) benefit	1,295	333,868	(332,573)
Production:			
Oil MBbls	9,343	7,028	2,315
Natural Gas Mmcf	6,192	5,887	305
Natural gas liquids MBbls	755	456	299
Total MBoe*(1)*	11,130	8,465	2,665
Average daily production Boe*(1)*	40,769	31,007	9,762
Average price per unit*(2)*:			
Oil price Bbl	$ 90.77	$ 95.64	$ (4.87)
Natural gas price Mcf	4.52	3.39	1.13
Natural gas liquids price Bbl	37.61	35.04	2.57
Total per Boe*(1)*	81.26	83.65	(2.39)
Average cost per Boe:			
Production:			
Lease operating	$ 8.60	$ 11.18	$ (2.58)
Workover and other	1.13	0.51	0.62
Taxes other than income	7.46	7.40	0.06
Gathering and other	1.63	0.82	0.81
Restructuring	0.09	0.06	0.03
General and administrative:			
General and administrative	6.85	10.26	(3.41)
Share-based compensation	1.24	1.42	(0.18)
Depletion	34.25	36.94	(2.69)

(1) *Natural gas reserves are converted to oil reserves using a ratio of six Mcf to one Bbl of oil. This ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.*

(2) *Amounts exclude the impact of cash paid/received on settled contracts as we did not elect to apply hedge accounting.*

For the nine months ended September 30, 2014, oil, natural gas and natural gas liquids revenues increased $196.4 million from the same period in 2013. The increase was primarily due to increased production volumes associated with the development of properties in the Bakken / Three Forks and El Halcón areas. These areas collectively accounted for an increase of approximately 17,000 Boe/d and $367.0 million of incremental revenues. The increase was partially offset by production decreases due to our divestitures of non-core properties during late 2013 and 2014. Also partially offsetting the increased production was a decrease in realized average prices per Boe, which decreased $2.39 to $81.26 per Boe.

Lease operating expenses increased $1.0 million for the nine months ended September 30, 2014, primarily due to $44.8 million of costs incurred in our core areas and the increase in production within these areas as we continue to carry out our development plan. This increase was partially offset by our divestiture of non-core properties in 2013 and 2014 which, historically, had higher relative operating costs. Lease operating expenses were $8.60 per Boe for the nine months ended September 30, 2014, compared to $11.18 per Boe for the same period in 2013. The decrease in lease operating expenses per Boe results from the increase in our production and efforts to reduce costs since the comparable 2013 period.

Workover expenses increased $8.3 million for the nine months ended September 30, 2014 compared to the same period in 2013 primarily due to $6.2 million of expenses associated with our core areas and an increase in activity in these areas.

Taxes other than income increased $20.4 million for the nine months ended September 30, 2014 as compared to the same period in 2013 primarily due to $32.3 million of taxes associated with increased production as we continue to carry out our development plan. The increase was partially offset by a decrease in production associated with non-core properties we divested in 2013 and 2014. Most production taxes are based on realized prices at the wellhead. As revenues or volumes from oil and natural gas sales increase or decrease, production taxes on these sales also increase or decrease. On a per unit basis, taxes other than income were $7.46 per Boe and $7.40 per Boe for the nine months ended September 30, 2014 and 2013, respectively.

Gathering and other expenses for the nine months ended September 30, 2014 and 2013 were $18.1 million and $6.9 million, respectively. The $18.1 million of expenses incurred for the nine months ended September 30, 2014 primarily relate to gathering and other fees paid on our oil and natural gas production, which has increased 31% compared to the prior year period.

In conjunction with our divestitures of certain non-core properties, we incurred approximately $1.0 million in severance costs and accelerated stock-based compensation expense related to the termination of certain employees for the nine months ended September 30, 2014. In March 2012, we announced our intention to close our Plano, Texas office and began the process of relocating key administrative functions to our corporate headquarters in Houston, Texas. As part of this restructuring, we offered severance and retention benefits to affected employees. As of May 2013, the requisite service period had ended and all severance and retention related payments had been made.

General and administrative expense for the nine months ended September 30, 2014 decreased $10.6 million to $76.3 million as compared to the same period in 2013. The decrease in general and administrative expenses results from decreases in professional fees, salaries and benefits, and office expenses amounting to $10.0 million, $2.4 million and $2.9 million, respectively. The decrease was partially offset by increases in transaction costs of approximately $3.2 million primarily related to non-core divestitures. On a per unit basis, general and administrative expenses were $6.85 per Boe and $10.26 per Boe, for the nine months ended September 30, 2014 and 2013, respectively.

Share-based compensation expense for the nine months ended September 30, 2014 was $13.8 million, an increase of $1.8 million compared to the same period in 2013. The increase in share-based compensation expense results from additional awards to employees and directors subsequent to the prior year period.

Depletion for oil and natural gas properties is calculated using the unit of production method, which depletes the capitalized costs of evaluated properties plus future development costs based on the ratio of production for the current period to total reserve volumes of evaluated properties as of the beginning of the period. Depletion expense increased $68.5 million to $381.2 million for the nine months ended September 30, 2014 compared to the same period in 2013, primarily due to increased production associated with the development of properties in the Bakken / Three Forks and El Halcón areas. On a per unit basis, depletion expense was $34.25 per Boe for the nine months ended September 30, 2014 compared to $36.94 per Boe for the nine months ended September 30, 2013. The decrease in the depletion rate per Boe is partially attributable to decreases in the amortizable base due to the full cost ceiling test impairments since the prior year period.

Accretion expense is a function of changes in the present value of our asset retirement obligations from period to period. We recorded accretion expense of $1.4 million for the nine months ended September 30, 2014, compared to $2.8 million for the same period in 2013. The decrease in accretion expense is attributable to our divestiture of non-core properties and associated asset retirement obligations in 2013 and 2014.

We utilize the full cost method of accounting to account for our oil and natural gas exploration and development activities. Under this method of accounting, we are required on a quarterly basis to determine whether the book value of our oil and natural gas properties (excluding unevaluated properties) is less than or equal to the "ceiling", based upon the expected after tax present value (discounted at 10%) of the future net cash flows from our proved reserves. Any excess of the net book value of our oil and natural gas properties over the ceiling must be recognized as a non-cash impairment expense. We recorded a full cost ceiling test impairment before income taxes of $61.2 million during the three months ended March 31, 2014. At September 30, 2013, our costs exceeded our ceiling limitation by $909.1 million, resulting in a write-down of our oil and natural gas properties before income taxes. During the three months ended September 30, 2013, we transferred $655.7 million of unevaluated property costs to the full cost pool primarily related to Woodbine assets in East Texas where capital was reallocated to El Halcón, and certain Utica/Point Pleasant assets in Northwest Pennsylvania related to non-economical drilling results obtained in the third quarter of 2013. The combined impact of less favorable oil price differentials adversely affecting proved reserve values and the aforementioned transfers of unevaluated properties to the full cost pool contributed to the ceiling impairment. Changes in production rates, levels of reserves, future development costs, transfers of unevaluated properties, commodity prices, and other factors will determine our actual ceiling test calculation and impairment analyses in future periods.

We review our gas gathering systems and equipment and other operating assets for impairment in accordance with ASC 360. For the nine months ended September 30, 2014, we recorded non-cash impairment charge of $3.8 million related to the disposition of midstream infrastructure assets associated with certain non-core property divestitures. For the nine months ended September 30, 2013, we recorded a non-cash impairment charge of $67.3 million. The impairment relates to our gross investments of $68.3 million in gas gathering infrastructure that will not be economically recoverable due to our shift in exploration, drilling and developmental plans from the Woodbine area to El Halcón during the third quarter of 2013.

During the third quarter of 2013, we performed our annual goodwill impairment test, and based on this review; we recorded a non-cash impairment charge of $228.9 million to reduce the carrying value of goodwill to zero. In the first step of the goodwill impairment test, we determined that the fair value of our reporting unit was less than the carrying amount, including goodwill, primarily due to pricing deterioration in the NYMEX forward pricing curve coupled with less favorable oil price differentials in our core areas, both factors which adversely impacted the fair value of our proved reserves. Therefore, we performed the second step of the goodwill impairment test, which led us to conclude that there would be no remaining implied fair value attributable to goodwill.

Table of Contents

We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil and natural gas production. Consistent with prior years, we have elected not to designate any positions as cash flow hedges for accounting purposes, and accordingly, we recorded the net change in the mark-to-market value of these derivative contracts in the unaudited condensed consolidated statements of operations. At September 30, 2014, we had a $43.9 million derivative asset, $19.7 million of which was classified as current, and we had a $18.8 million derivative liability, $1.2 million of which was classified as current. We recorded a net derivative gain of $8.6 million ($36.9 million net unrealized gain and $28.3 million net realized loss on settled contracts and premium costs) for the nine months ended September 30, 2014 compared to a net derivative loss of $38.8 million ($20.4 million net unrealized loss and $18.4 million net realized loss on settled contracts and premium costs), in the same period in 2013.

Interest expense increased $82.9 million for the nine months ended September 30, 2014 from the same period in 2013. Capitalized interest for the nine months ended September 30, 2014 and 2013 was $129.5 million and $159.6 million, respectively. This decrease in capitalized interest was driven by decreases in our unevaluated properties since September 30, 2013, which is the basis of our capitalized interest calculation. Interest expense subject to capitalization increased to $237.5 million in the nine months ended September 30, 2014 from $186.0 million in the comparable prior year period. The increase in interest subject to capitalization is due to our issuance of the 2022 Notes and the issuance of the additional 2020 Notes since the prior year period.

We recorded an income tax benefit of $1.3 million for the nine months ended September 30, 2014 due to an offsetting valuation allowance and expected tax refunds, as discussed further in Item 1. *Condensed Consolidated Financial Statements (Unaudited)* Note 11,*"Income Taxes,"* compared to an income tax benefit of $333.9 million due to our pre-tax loss of $1.1 billion in the comparable prior year period. The effective tax rate for the nine months ended September 30, 2014 was (2.3)% compared to 29.1% for the nine months ended September 30, 2013. The change in effective tax rate is due to the valuation allowance recorded against our net deferred tax assets as of September 30, 2014 and expected refunds from the filing of tax returns during the three months ended September 30, 2014.

Recently Issued Accounting Pronouncements

We discuss recently adopted and issued accounting standards in Item 1. *Condensed Consolidated Financial Statements (Unaudited)* Note 1, *"Financial Statement Presentation."*

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Derivative Instruments and Hedging Activity

We are exposed to various risks, including energy commodity price risk. When oil, natural gas, and natural gas liquids prices decline significantly our ability to finance our capital budget and operations may be adversely impacted. Commodity prices have been and we expect them to remain volatile and unpredictable; therefore, we have designed a risk management policy utilizing derivative instruments to provide partial protection against declines in commodity prices by reducing our exposure to price volatility and the affect it could have on our cash flows and operations. The types of derivative instruments that we typically utilize include costless collars, swaps, and put options. The total volumes that we hedge through the use of derivative instruments varies from period to period, however, generally our objective is to hedge approximately 70% to 80% of our current and anticipated production for the next 18 to 24 months. Our hedge policies and objectives may change significantly as our operational profile changes and/or commodities prices change. We do not enter into derivative contracts for speculative trading purposes.

We are exposed to market risk on our open derivative contracts related to potential non-performance by our counterparties. It is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competitive market makers. Each of the counterparties to our derivative contracts is a lender or an affiliate of a lender under our Senior Credit Agreement. We typically do not specifically post collateral under any of these contracts as they are secured by liens under our Senior Credit Agreement. Please refer to Item 1. *Condensed Consolidated Financial Statements (Unaudited)* Note 6,"*Derivative and Hedging Activities"* for additional information.

We are also exposed to interest rate risk on our variable interest rate debt. If interest rates increase, our interest expense would increase and our available cash flows would decrease. Historically, we entered into interest rate swaps which reduce exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. At September 30, 2014 and 2013, we did not have any open positions converting our variable interest rate debt to fixed interest rates. We continue to monitor our exposure to interest rate fluctuations as we incur indebtedness with variable interest rates and enter into swaps in accordance with our risk management policy when we believe it is warranted.

We account for our derivative activities under the provisions of ASC 815, *Derivatives and Hedging* (ASC 815). ASC 815 establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. Please refer to Item 1. *Condensed Consolidated Financial Statements (Unaudited)* Note 6,"*Derivative and Hedging Activities"* for additional information.

Fair Market Value of Financial Instruments

The estimated fair values for financial instruments under ASC 825, *Financial Instruments* (ASC 825) are determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. See Item 1. *Condensed Consolidated Financial Statements (Unaudited)* Note 5, "*Fair Value Measurements"* for additional information.

Interest Rate Sensitivity

We are also exposed to market risk related to adverse changes in interest rates. Our interest rate risk exposure results primarily from fluctuations in short-term rates, which are LIBOR and ABR based and may result in reductions of earnings or cash flows due to increases in the interest rates we pay on these obligations.

At September 30, 2014, total long-term debt was approximately $3.5 billion of which approximately 90% bears interest at a weighted average fixed interest rate of 9.2% per year. The remaining 10% of our total debt balance at September 30, 2014 bears interest at floating or market interest rates that, at our option, are tied to prime rate or LIBOR. Fluctuations in market interest rates will cause our annual interest costs to fluctuate. At September 30, 2014, the weighted average interest rate on our variable rate debt was 2.3% per year. If the balance of our variable rate debt at September 30, 2014 were to remain constant, a 10% change in market interest rates would impact our cash flow by approximately $0.2 million per quarter.

Item 4. Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we evaluated the design and operation of our disclosure controls and procedures (as defined in rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, or the Exchange Act) as of September 30, 2014. On the basis of this review, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures are designed, and are effective, to give reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and to ensure that information required to be disclosed in the reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, in a manner that allows timely decisions regarding required disclosure.

We did not have any change in our internal controls over financial reporting during the quarter ended September 30, 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

On May 14, 2013, the Committee of Sponsoring Organizations of the Treadway Commission (COSO) issued an updated version of its Internal Control Integrated Framework (the 2013 Framework). Originally issued in 1992 (the 1992 Framework), the framework helps organizations design, implement and evaluate the effectiveness of internal controls and simplifies their use and application. The 1992 Framework remains available during the transition period, which extends to December 15, 2014, after which time COSO will consider it as superseded by the 2013 Framework. As of September 30, 2014, we continued to utilize the 1992 Framework and will transition to the 2013 Framework by the end of 2014.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

From time to time, we may be a plaintiff or defendant in a pending or threatened legal proceeding arising in the normal course of our business. While the outcome and impact of currently pending legal proceedings cannot be determined, our management and legal counsel believe that the resolution of these proceedings through settlement or adverse judgment will not have a material effect on our consolidated operating results, financial position or cash flows.

Item 1A. Risk Factors

There have been no changes to the risk factors described in our Annual Report on Form 10-K for the fiscal year ended December 31, 2013, except as described below.

Requirements to reduce gas flaring in North Dakota could have an adverse effect on our operations.

Wells in the Bakken / Three Forks formations in North Dakota, where we have significant operations, yield natural gas as a byproduct of oil production. Bottlenecks in the current gas gathering network in certain areas have resulted in some of that natural gas being flared instead of processed. The North Dakota Industrial Commission (NDIC), the State's chief energy regulator, recently issued an order to reduce the volume of natural gas flared from oil wells in the Bakken / Three Forks formations. The State's objectives are to cause operators to capture 74 percent of the natural gas by the fourth quarter 2014, 77 percent by the first quarter 2015, 85 percent by the first quarter 2016, and 90 percent, with the potential for 95 percent, by the fourth quarter 2020. In addition, the NDIC is requiring operators to develop gas capture plans that describe how much natural gas is expected to be produced, how it will be delivered to a processor and where it will be processed. Production caps or penalties will be imposed on certain wells that cannot meet the capture goals. These capture requirements, and any similar future obligations in North Dakota or our other locations, may increase our operational costs or restrict our production, which could materially and adversely affect our financial condition, results of operations and cash flows.

Table of Contents

Crude oil from the Bakken / Three Forks formations may pose unique hazards that may have an adverse effect on our operations.

The U.S. Department of Transportation (USDOT) recently concluded that crude oil from the Bakken / Three Forks formations has a higher volatility than most other U.S. crude oil and thus is more ignitable and flammable. Based on that information, and several fires involving rail transportation of crude oil, USDOT has started a rulemaking to develop new requirements for shipping crude oil by rail. Any new regulations that significantly affect transportation of crude oil production could materially and adversely affect our financial condition, results of operations and cash flows.

Federal, state and local legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with many of the wells for which we are the operator. Federal, state, tribal and local governments have been adopting or considering restrictions on or prohibitions of fracturing in areas where we currently conduct operations, or in the future plan to conduct operations. Consequently, we could be subject to additional levels of regulation, operational delays or increased operating costs and could have additional regulatory burdens imposed upon us that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

From time to time, for example, legislation has been proposed in Congress to amend the federal Safe Drinking Water Act to require federal permitting of hydraulic fracturing and the disclosure of chemicals used in the hydraulic fracturing process. Further, the Environmental Protection Agency (EPA) is conducting a wide-ranging study on the effects of hydraulic fracturing on drinking water resources. In December 2012, the EPA issued a progress report describing its ongoing study, and announcing its expectation that a final draft report will be released for public comment and peer review in 2014. Other governmental reviews have also been recently conducted or are under way that focus on environmental aspects of hydraulic fracturing, including, for example, a federal Bureau of Land Management rulemaking for hydraulic fracturing practices on federal and Indian lands that has resulted in a May 2013 proposal that would require public disclosure of chemicals used in hydraulic fracturing, confirmation that the wells used in fracturing operations meet proper construction standards and development of plans for managing related flowback water. These activities could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

Certain states, including North Dakota, Ohio, Pennsylvania, and Texas where we conduct operations, likewise are considering or have adopted more stringent requirements for various aspects of hydraulic fracturing operations, such as permitting, disclosure, air emissions, well construction, seismic monitoring, waste disposal and water use. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general or hydraulic fracturing in particular. Such efforts have extended to bans on hydraulic fracturing. On December 19, 2013, the Pennsylvania Supreme Court overturned several portions of Pennsylvania's law regulating hydraulic fracturing, allowing local governments in Pennsylvania to regulate hydraulic fracturing through local land use regulations. Other local jurisdictions, including Dallas, Texas and several cities in Colorado, have adopted restrictions on hydraulic fracturing, and anti-hydraulic fracturing activists are seeking more such controls.

The proliferation of regulations may limit our ability to operate. If the use of hydraulic fracturing is limited, prohibited or subjected to further regulation, these requirements could delay or effectively prevent the extraction of oil and natural gas from formations which would not be economically viable without the use of hydraulic fracturing. This could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Regulation related to global warming and climate change could have an adverse effect on our operations and demand for oil and natural gas.

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response to these studies, governments have been adopting domestic and international climate change regulations that require reporting and reductions of the emission of greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change, and the Kyoto Protocol address greenhouse gas emissions, and several countries, including those comprising the European Union, have established greenhouse gas regulatory systems.

In the United States, many states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories, emission targets, greenhouse gas cap and trade programs or incentives for renewable energy generation, while others have considered adopting such greenhouse gas programs.

At the federal level, the Obama Administration is attempting to address climate change through a variety of administrative actions. The EPA has issued greenhouse gas monitoring and reporting regulations that went into effect January 1, 2010, and required reporting by regulated facilities by March 2011 and annually thereafter. In November 2010, the EPA extended the reporting obligation to oil and natural gas facilities. On July 19, 2011, the EPA amended the oil and natural gas facility greenhouse gas reporting rule to require reporting beginning in September 2012. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding certain greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding served as the first step to issuing regulations that require permits for and reductions in greenhouse gas emissions for certain facilities. In March 2014, moreover, the President released a Strategy to Reduce Methane Emissions that includes consideration of both voluntary programs and targeted regulations for the oil and gas sector. Towards that end, the EPA has released five draft white papers on methane and volatile organic compound emissions and mitigation measures for natural gas compressors, hydraulically fractured oil wells, pneumatic devices, well liquids unloading facilities and natural gas production and transmission facilities. The EPA is seeking responses to the white papers and intends to use this process to determine how best to pursue additional emission reductions from the oil and natural gas sector. Also as part of the President's strategy, the federal Bureau of Land Management is expected to propose standards for reducing venting and flaring on public lands.

In the courts, several decisions have been issued that may increase the risk of claims being filed by governments and private parties against companies that have significant greenhouse gas emissions. Such cases may seek to challenge air emissions permits that greenhouse gas emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur additional operating costs, such as costs to purchase and operate emissions controls or other compliance costs, and reduce demand for our products.

Table of Contents

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

The following table sets forth information regarding our acquisition of shares of common stock for the periods presented.

	Total Number of Shares Purchased[1]	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
July 2014	213	$ 6.65		
August 2014	2,669	5.38		
September 2014	1,649	4.38		

(1) *All of the shares were surrendered by employees in satisfaction of tax obligations upon the vesting of restricted stock awards. The acquisition of the surrendered shares was not part of a publicly announced program to repurchase shares of our common stock, nor were they considered as or accounted for as treasury shares.*

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Table of Contents

Item 6. Exhibits

The following documents are included as exhibits to this Quarterly Report on Form 10-Q. Those exhibits incorporated by reference are so indicated by the information supplied with respect thereto. Those exhibits which are not incorporated by reference are attached hereto.

2.1 Agreement of Sale and Purchase by and among Halcón Energy Properties, Inc., Halcón Field Services, LLC, HK Energy, LLC, Halcón Operating Co, Inc., HK Energy Operating, LLC, and Halcón Resources Operating, Inc., and New Gulf Resources, LLC, dated February 25, 2014 (Incorporated by reference to Exhibit 2.1 of our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2014 filed May 8, 2014).

2.2 Amendment No. 1 Agreement of Sale and Purchase by and among Halcón Energy Properties, Inc., Halcón Field Services, LLC, HK Energy, LLC, Halcón Operating Co, Inc., HK Energy Operating, LLC, and Halcón Resources Operating, Inc., and New Gulf Resources, LLC, dated April 10, 2014 (Incorporated by reference to Exhibit 2.2 of our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2014 filed July 31, 2014).

3.1 Amended and Restated Certificate of Incorporation of RAM Energy Resources, Inc. dated February 8, 2012 (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed February 9, 2012).

3.2 Certificate of Amendment of the Amended and Restated Certificate of Incorporation of Halcón Resources Corporation, effective as of February 10, 2012 (Incorporated by reference to Exhibit 3.2 of our Current Report on Form 8-K filed February 9, 2012).

3.3 Certificate of Designation, Preferences, Rights and Limitations of 8% Automatically Convertible Preferred Stock of Halcón Resources Corporation dated March 2, 2012 (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed March 5, 2012).

3.4 Certificate of Elimination of 8% Automatically Convertible Preferred Stock dated November 30, 2012 (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed December 4, 2012).

3.5 Certificate of Designation, Preferences, Rights and Limitations of 8% Automatically Convertible Preferred Stock of Halcón Resources Corporation dated December 5, 2012 (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed December 11, 2012).

3.6 Certificate of Amendment of the Amended and Restated Certificate of Incorporation of Halcón Resources Corporation dated January 17, 2013 (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed January 23, 2013).

3.7 Certificate of Amendment of the Amended and Restated Certificate of Incorporation of Halcón Resources Corporation, effective as of May 23, 2013 (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed May 29, 2013).

3.8 Certificate of Designations, Preferences, Rights and Limitations of 5.75% Series A Convertible Perpetual Preferred Stock of Halcón Resources Corporation (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed June 18, 2013).

3.9 Certificate of Elimination of 8% Automatically Convertible Preferred Stock of Halcón Resources Corporation (Incorporated by reference to Exhibit 3.2 of our Current Report on Form 8-K filed June 18, 2013).

3.10	Certificate of Amendment of the Amended and Restated Certificate of Incorporation, effective as of May 22, 2014 (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed May 27, 2014).
3.11	Fourth Amended and Restated Bylaws of Halcón Resources Corporation (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed November 6, 2012).
4.1	Convertible Promissory Note dated February 8, 2012, between Halcón Resources Corporation and HALRES LLC (formerly Halcón Resources LLC) (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed February 9, 2012).
4.2	Warrant Certificate dated February 8, 2012, between Halcón Resources Corporation and HALRES LLC (formerly Halcón Resources LLC) (Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed February 9, 2012).
4.3	Registration Rights Agreement dated February 8, 2012, between Halcón Resources Corporation and HALRES LLC (formerly Halcón Resources LLC) (Incorporated by reference to Exhibit 4.3 of our Current Report on Form 8-K filed February 9, 2012).
4.4	Indenture dated as of July 16, 2012, among Halcón Resources Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as Trustee, relating to Halcón Resources Corporation's 9.75% Senior Notes due 2020 (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed July 17, 2012).
4.5	Registration Rights Agreement dated July 16, 2012, among Halcón Resources Corporation, the subsidiary guarantors named therein, and the initial purchaser named therein (Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed July 17, 2012).
4.6	First Supplemental Indenture dated as of August 1, 2012, by and among Halcón Resources Corporation, the parties named therein as subsidiary guarantors, and U.S. Bank National Association, as Trustee, relating to the 9.75% senior notes due 2020 (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed August 2, 2012).
4.7	Second Supplemental Indenture dated as of August 1, 2012, by and among Halcón Resources Corporation, the parties named therein as subsidiary guarantors, and U.S. Bank National Association, as Trustee, relating to the 9.75% senior notes due 2020 (Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed August 2, 2012).
4.8	Registration Rights Agreement dated as of August 1, 2012, among CH4 Energy II, LLC, PetroMax Leon, LLC and Petro Texas LLC and Halcón Resources Corporation (subsequently joined by U.S. King King LLC) (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed August 7, 2012).
4.9	Registration Rights Agreement dated March 5, 2012, between Halcón Resources Corporation and Barclays Capital, Inc. as lead placement agent for the benefit of the initial holders named therein (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed March 5, 2012).
4.10	Registration Rights Agreement dated as of November 6, 2012, among Halcón Resources Corporation, the subsidiary guarantors named therein, and the initial purchaser named therein (Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed November 7, 2012).

Table of Contents

4.11 Indenture dated as of November 6, 2012, among Halcón Resources Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as Trustee, relating to Halcón Resources Corporation's 8.875% Senior Notes due 2021 (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed November 7, 2012).

4.12 First Supplemental Indenture dated December 6, 2012, among Halcón Williston I, LLC and Halcón Williston II, LLC, the existing guarantors, Halcón Resources Corporation, the parties named therein as subsidiary guarantors and U.S. Bank National Association, as trustee, relating to the 8.875% senior notes due 2021 (Incorporated by reference to Exhibit 4.3 of our Current Report on Form 8-K filed December 11, 2012).

4.13 Third Supplemental Indenture dated December 6, 2012, among Halcón Resources Corporation and U.S. Bank National Association, as Trustee, relating to the 9.75% senior notes due 2020 (Incorporated by reference to Exhibit 4.4 of our Current Report on Form 8-K filed December 11, 2012).

4.14 Registration Rights Agreement dated December 6, 2012, between Halcón Resources Corporation and Petro-Hunt Holdings LLC and Pillar Holdings LLC (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed December 11, 2012).

4.15 First Amendment to Registration Rights Agreement dated December 6, 2012, between Halcón Resources Corporation and HALRES LLC (formerly Halcón Resources LLC) (Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed December 11, 2012).

4.16 Registration Rights Agreement, dated as of January 14, 2013, between Halcón Resources Corporation and Wells Fargo Securities, LLC, on behalf of the initial purchasers named therein (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed January 15, 2013).

4.17 Waiver, dated July 3, 2013, relating to Registration Rights Agreement dated December 6, 2012 by and among Halcón Resources Corporation and Petro-Hunt Holdings, LLC and Pillar Holdings, LLC (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed July 10, 2013).

4.18 Indenture dated as of August 13, 2013, among Halcón Resources Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as Trustee, relating to Halcón Resources Corporation's 9.25% Senior Notes due 2022 (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed August 13, 2013).

4.19 Registration Rights Agreement dated as of August 13, 2013, among Halcón Resources Corporation and BMO Capital Markets Corp., on behalf of the initial purchaser named therein (Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed August 13, 2013).

4.20 Registration Rights Agreement, dated as of December 19, 2013, between Halcón Resources Corporation and Barclays Capital Inc. and Wells Fargo Securities, LLC as the initial purchasers (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed December 20, 2013).

10.1 Seventh Amendment to Senior Revolving Credit Agreement, dated as of March 21, 2014, among Halcón Resources Corporation, as borrower, each of the lenders party thereto, and JPMorgan Chase Bank, N.A., as administrative agent for the lenders (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed March 27, 2014).

Table of Contents

10.2	Eighth Amendment to Senior Revolving Credit Agreement, dated as of September 30, 2014, among Halcón Resources Corporation, as borrower, each of the lenders party thereto, and JPMorgan Chase Bank, N.A., as administrative agent for the lenders (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed October 2, 2014).
10.3	Employment Agreement between Charles E. Cusack, III and Halcón Resources Corporation dated November 8, 2012 (Incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed March 27, 2014).
10.4	Form of Performance Unit Award Agreement (Incorporated by reference to Exhibit 10.3 of our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2014 filed July 31, 2014).
12.1*	Computation of Ratio of Earnings to Combined Fixed Charges and Preference Dividends
31.1*	Sarbanes-Oxley Section 302 certification of Principal Executive Officer
31.2*	Sarbanes-Oxley Section 302 certification of Principal Financial Officer
32*	Sarbanes-Oxley Section 906 certification of Principal Executive Officer and Principal Financial Officer
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

* *Attached hereto.*

Indicates management contract or compensatory plan or arrangement.

Table of Contents

SIGNATURES

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

	HALCÓN RESOURCES CORPORATION
November 10, 2014	By: /s/ FLOYD C. WILSON Name: Floyd C. Wilson Title: *Chairman of the Board and Chief Executive Officer*
November 10, 2014	By: /s/ MARK J. MIZE Name: Mark J. Mize Title: *Executive Vice President, Chief Financial Officer and Treasurer*
November 10, 2014	By: /s/ JOSEPH S. RINANDO, III Name: Joseph S. Rinando, III Title: *Vice President and Chief Accounting Officer*