HALCON RESOURCES CORP
Form 10-Q
November 08, 2012
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2012

OR

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

For the transition period from to

Commission File Number: 001-35467

Halcón Resources Corporation

(Exact name of registrant as specified in its charter)

Delaware	**1311**	**20-0700684**
(State or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification Number)

1000 Louisiana Street, Suite 6700, Houston, TX 77002

(Address of principal executive offices)

(832) 538-0300

(Registrant s telephone number, including area code)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding twelve months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

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

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

Large Accelerated Filer o	Accelerated Filer x
Non-Accelerated Filer o (Do not check if a smaller reporting company)	Smaller Reporting Company o

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

At November 5, 2012, 216,217,427 shares of the Registrant s Common Stock were outstanding.

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Third Quarter 2012 Form 10-Q Report

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Special note regarding forward-looking statements

This Quarterly Report on Form 10-Q contains, and we may from time to time otherwise make in other public filings, press releases and presentations, forward-looking statements within the meaning of the federal securities laws. All statements, other than statements of historical facts, concerning, among other things, planned or pending acquisitions, including expectations regarding closings, capital expenditures, potential increases in oil and natural gas production, the number and location of anticipated wells to be drilled in the future, future cash flows and borrowings, pursuit of potential acquisition opportunities, our financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. These forward-looking statements are identified by their use of terms and phrases such as may, expect, estimate, project, plan, believe, intend, achievable, anticipate, will, continue, potential, should, could and sin Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Actual results could differ materially from those anticipated in these forward-looking statements. You should consider carefully the risks discussed under the Risk Factors section of our previously filed Annual Report on Form 10-K for the year ended December 31, 2011, and the other disclosures contained herein and therein, which describe factors that could cause our actual results to differ from those anticipated in the forward-looking statements, including, but not limited to, the following factors:

- volatility in commodity prices for oil, natural gas liquids (or NGLs) and natural gas;

- our ability to successfully identify and acquire oil and natural gas properties, prospects and leaseholds, including undeveloped acreage in new and emerging resource plays;

- our ability to successfully integrate acquired oil and natural gas businesses and operations, including our recently closed acquisition of GeoResources, Inc. (GeoResources) and assets in East Texas;

- the possibility that acquisitions may involve unexpected costs or delays, will not achieve intended benefits and will divert management s time and energy, which could have an adverse effect on our financial position, results of operations or cash flows;

- the possibility that our industry may be subject to future regulatory or legislative actions (including any additional taxes and changes in environmental regulation);

- the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs;

- our ability to generate sufficient cash flow from operations, or access to capital through borrowings or other sources to fully execute our business plans;

- our ability to economically replace oil and natural gas reserves;
- environmental risks;
- drilling and operating risks;
- exploration and development risks;
- competition, including competition for acreage in resource play areas;
- management s ability to execute our plans to meet our goals;
- our ability to attract and retain key members of senior management and key technical employees;
- the cost and availability of goods and services, such as drilling rigs, fracture stimulation services and tubulars;
- access to and availability of water and other treatment materials to carry out planned fracture stimulations of our wells;
- access to adequate gathering systems and transportation take-away capacity to handle our expected production;

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- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business, may be less favorable than expected, including the possibility that the economic conditions in the United States will worsen and that capital markets are disrupted, which could adversely affect demand for oil, NGLs and natural gas and/or make it difficult to access financial markets;

- social unrest, political instability, armed conflict, or acts of terrorism or sabotage in oil and natural gas producing regions, such as the Middle East and Africa, or our markets;

- other economic, competitive, governmental, legislative, regulatory, geopolitical and technological factors that may negatively impact our business, operations or pricing; and

- hurricanes on the Gulf Coast and severe winter weather in North Dakota and Montana may cause us to be subject to production curtailments in the future due to damage to certain field or, even in the event producing field is not damaged, production could be curtailed due to damage to facilities and equipment owned by oil and gas purchaser, or vendors and suppliers.

All forward-looking statements are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this document. Other than as required under the securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements (Unaudited)

HALCÓN RESOURCES CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS (Unaudited)

(In thousands, except per share amounts)

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Operating revenues:				
Oil, natural gas and natural gas liquids sales				
Oil	$ 65,662	$ 18,955	$ 109,042	$ 62,150
Natural gas	3,775	2,548	6,683	8,252
Natural gas liquids	3,214	2,644	7,006	7,582
Total oil, natural gas and natural gas liquids sales	72,651	24,147	122,731	77,984
Other	489	39	560	124
Total operating revenues	73,140	24,186	123,291	78,108
Operating expenses:				
Production:				
Lease operating	15,511	7,363	32,121	23,016
Workovers	1,123	136	2,384	1,032
Taxes	4,432	1,391	7,354	4,280
Restructuring	725		1,732	
General and administrative	33,192	3,972	66,613	13,140
Depletion, depreciation and accretion	22,726	5,594	34,661	16,877
Total operating expenses	77,709	18,456	144,865	58,345
Income (loss) from operations	(4,569)	5,730	(21,574)	19,763
Other income (expenses):				
Interest expense and other, net	(5,074)	(3,455)	(22,250)	(14,318)
Net gain (loss) on derivative contracts	(9,575)	22,617	(849)	16,635
Total other income (expenses)	(14,649)	19,162	(23,099)	2,317
Income (loss) before income taxes	(19,218)	24,892	(44,673)	22,080
Income tax provision	963	13,116	1,171	11,279
Net income (loss)	(20,181)	11,776	(45,844)	10,801
Non-cash preferred dividend			(88,445)	
Net income (loss) available to common stockholders	$ (20,181)	$ 11,776	$ (134,289)	$ 10,801
Net income (loss) per common share:				
Basic	$ (0.11)	$ 0.45	$ (1.01)	$ 0.41
Diluted	$ (0.11)	$ 0.45	$ (1.01)	$ 0.41
Weighted average common shares outstanding:				

Basic	191,846	26,362	132,460	26,254
Diluted	191,846	26,362	132,460	26,254

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

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HALCÓN RESOURCES CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited)

(In thousands, except share and per share amounts)

	September 30, 2012	December 31, 2011
Current assets:		
Cash and cash equivalents	$ 18,126	$ 49
Accounts receivable	105,288	10,288
Receivables from derivative contracts	4,324	260
Income tax receivable	9,850	
Deferred income taxes	533	2,601
Inventory	8,621	4,310
Prepaids and other	4,061	2,729
Total current assets	150,803	20,237
Oil and natural gas properties (full cost method):		
Evaluated	1,710,797	715,666
Unevaluated	1,197,764	
Gross oil and natural gas properties	2,908,561	715,666
Less: accumulated depletion and impairment	(534,134)	(501,993)
Net oil and natural gas properties	2,374,427	213,673
Other operating property and equipment:		
Other operating assets and equipment	32,502	9,979
Less: accumulated depreciation	(7,463)	(7,133)
Net other operating property and equipment	25,039	2,846
Other non-current assets:		
Receivables from derivative contracts	1,023	
Debt issuance costs, net of amortization	23,531	5,966
Deferred income taxes		24,102
Equity in oil and gas partnerships	11,207	
Funds in escrow	3,550	560
Goodwill	160,918	
Other	939	418
Total assets	$ 2,751,437	$ 267,802
Current liabilities:		
Accounts payable and accrued liabilities	$ 202,344	$ 25,061
Liabilities from derivative contracts	1,654	265
Asset retirement obligations	1,968	1,010
Total current liabilities	205,966	26,336
Long-term debt	1,175,000	202,000
Other non-current liabilities:		
Liabilities from derivative contracts	254	805
Asset retirement obligations	42,651	32,703
Deferred income taxes	213,742	
Other	10	10
Commitments and contingencies		
Stockholders equity:		
Preferred stock: 1,000,000 shares of $0.0001 par value authorized; no shares issued or outstanding		
Common stock: 336,666,666 and 33,333,333 shares of $0.0001 par value authorized; 217,867,336 and 27,694,583 shares issued; 216,217,427 and 26,244,452 outstanding at	22	3

September 30, 2012 and December 31, 2011, respectively				
Additional paid-in capital		1,385,244		229,414
Treasury stock: 1,649,909 and 1,450,131 shares at September 30, 2012 and December 31, 2011, respectively, at cost		(9,298)		(7,159)
Accumulated deficit		(262,154)		(216,310)
Total stockholders equity		1,113,814		5,948
Total liabilities and stockholders equity	$	2,751,437	$	267,802

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

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HALCÓN RESOURCES CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY (Unaudited)

(In thousands)

	Year Ended December 31 2011 and Nine Months Ended September 30, 2012								
	Preferred Stock		Common Stock		Additional Paid-In	Treasury Stock		Accumulated	Stockholders
	Shares	Amount	Shares	Amount	Capital	Shares	Amount	Deficit	Equity
BALANCE, December 31, 2010		$	27,533	$ 3	$ 226,047	1,404	$ (6,976)	$ (214,907)	$ 4,167
Long-term incentive plan grants			280						
Long-term incentive plan forfeitures			(118)						
Net loss								(1,403)	(1,403)
Repurchase of stock						46	(183)		(183)
Share-based compensation					3,367				3,367
BALANCE, December 31, 2011			27,695	3	229,414	1,450	(7,159)	(216,310)	5,948
Warrants issued					43,590				43,590
Sale of common stock			73,333	7	274,993				275,000
Reverse-stock-split rounding			4						
Sale of preferred stock	4	311,556							311,556
Preferred stock conversion	(4)	(385,476)	44,445	5	385,471				
Offering costs		(14,525)			(4,994)				(19,519)
Common stock issuance			72,114	7	452,032				452,039
Net loss								(45,844)	(45,844)
Preferred beneficial conversion feature					88,445				88,445
Non-cash preferred dividend		88,445			(88,445)				
Long-term incentive plan grants			276						
Repurchase of stock						200	(2,139)		(2,139)

Share-based compensation						4,738							4,738
BALANCE, September 30, 2012	$	217,867	$	22	$	1,385,244	1,650	$	(9,298)	$	(262,154)	$	1,113,814

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

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HALCÓN RESOURCES CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)

(In thousands)

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Cash flows from operating activities:		
Net income (loss)	$ (45,844)	$ 10,801
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation and accretion	34,661	16,877
Deferred income tax provision	1,030	11,129
Share-based compensation	3,866	2,227
Unrealized (gain) loss on derivative contracts	3,197	(16,391)
Amortization and write-off of deferred loan costs	6,247	3,325
Non-cash interest and amortization of discount	8,620	362
Other expense (income)	470	(22)
Changes in assets and liabilities, net of acquisitions:		
Accounts receivable	(25,609)	1,293
Inventory	(1,565)	(500)
Derivative premium		4,889
Prepaids and other	(1,653)	549
Accounts payable and accrued liabilities	30,674	(10,448)
Other	(526)	(278)
Net cash provided by operating activities	13,568	23,813
Cash flows from investing activities:		
Evaluated oil and natural gas capital expenditures	(93,073)	(19,600)
Unevaluated oil and natural gas capital expenditures	(634,622)	
Acquisition of GeoResources, Inc., net of cash acquired	(579,497)	
Acquisition of East Texas Assets	(296,139)	
Other operating property and equipment capital expenditures	(18,240)	(503)
Proceeds received from sales of property and equipment	554	473
Funds held in escrow	(2,989)	
Net cash used in investing activities	(1,624,006)	(19,630)
Cash flows from financing activities:		
Proceeds from borrowings	1,282,255	238,166
Repayments of borrowings	(328,000)	(235,222)
Debt issuance costs	(23,657)	(7,003)
Offering costs	(18,535)	
Common stock repurchased	(2,139)	(117)
Preferred stock issued	311,556	
Preferred beneficial conversion feature	88,445	
Common stock issued	275,000	
Warrants issued	43,590	
Net cash provided by (used in) financing activities	1,628,515	(4,176)

Net increase in cash		18,077		7
Cash at beginning of period		49		37
Cash at end of period	$	18,126	$	44

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

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HALCÓN RESOURCES CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited) Continued

(In thousands)

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Supplemental cash flow information:		
Cash paid for income taxes	$ 361	$ 531
Cash paid for interest, net of capitalized interest	3,931	12,036
Disclosure of non-cash investing and financing activities:		
Asset retirement obligations	$ 689	$ (23)
Preferred dividend	88,445	
Payment-in-kind interest	14,669	362
Common stock issued for GeoResources, Inc.	321,416	
Common stock issued for the East Texas Assets	130,623	

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

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HALCÓN RESOURCES CORPORATION

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. FINANCIAL STATEMENT PRESENTATION

Halcón Resources Corporation (Halcón or the Company) is an independent energy company engaged in the exploration, development and production of crude oil and natural gas properties located in the United States. The unaudited condensed consolidated financial statements include the accounts of all subsidiaries. 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 only 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 2011 Annual Report on Form 10-K, filed with the United States Securities and Exchange Commission (SEC). Please refer to the notes in the 2011 Annual Report on Form 10-K when reviewing interim financial results.

Consolidated Financial Statements

The unaudited condensed consolidated financial statements include the accounts of Halcón and its majority-owned subsidiaries. The equity method is used to account for investments in affiliates in which the Company does not have majority ownership, but has the ability to exert significant influence. The Company s investments in oil and gas limited partnerships for which it serves as general partner and exerts significant influence are accounted for under the equity method. Intercompany accounts and transactions have been eliminated.

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 accruals, oil and natural gas reserves, capital accruals, amortization relating to oil and natural gas properties, asset retirement obligations, fair value estimates, beneficial conversion feature 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.

Goodwill

During the third quarter of 2012, the Company recorded $160.9 million of goodwill as a result of the GeoResources, Inc. merger. Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the acquisition of a business. Goodwill is not amortized; rather, it is tested for impairment annually and when events or changes in circumstances indicate that fair value of a reporting unit with goodwill has been reduced below carrying value. The impairment test requires allocating goodwill and other assets and liabilities to reporting units. However, the Company has only one reporting unit. To assess impairment, the Company has the option to qualitatively assess if it is more likely than not that the fair value of the reporting unit is less than the book value. Absent a qualitative assessment, or, through the qualitative assessment, if the Company determines it is more likely than not that the fair value of the reporting unit is less than the book value; a quantitative assessment is prepared to calculate the fair market value of the reporting unit. If it is determined that the fair value of the reporting unit is less than the book value, the recorded goodwill is impaired to its implied fair value with a charge to operating expense.

The assumptions the Company will use in calculating our reporting unit fair value at the time of the test include our market capitalization and discounted future cash flows based on estimated reserves and production, future costs and future oil and natural gas

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prices. Material adverse changes to any of these factors could lead to an impairment of all or a portion of our goodwill in future periods.

Recently Issued Accounting Pronouncements

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in the U.S. Generally Accepted Accounting Principles (GAAP) and International Financial Accounting Reporting Standards (IFRS) . This pronouncement was issued to provide a consistent definition of fair value and ensure that the fair value measurement and disclosure requirements are similar between GAAP and IFRS. ASU 2011-04 changes certain fair value measurement principles and enhances the disclosure requirements particularly for Level 3 fair value measurements. This update is effective for reporting periods beginning on or after December 15, 2011. The adoption of ASU 2011-04 on January 1, 2012 did not have a material impact on the Company s financial position or results of operations.

In June 2011, the FASB issued ASU No. 2011-05, Presentation of Comprehensive Income . ASU 2011-05 eliminates the option to report other comprehensive income and its components in the statement of changes in stockholders equity and requires an entity to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement or in two separate but consecutive statements. This update is effective for fiscal years, and interim periods within those years beginning after December 15, 2011. In December 2011, the FASB issued ASU No. 2011-12, which became effective at the same time as ASU 2011-05, to defer the effective date of provisions of ASU 2011-05 that relate to the presentation of reclassification adjustments. Adoption of ASU 2011-05 and ASU 2011-12 did not have an impact on the Company s financial position or results of operations.

In December 2011, the FASB issued ASU No. 2011-11 which will enhance disclosures by requiring an entity to disclose information about netting arrangements, including rights of offset, to enable users of its financial statements to understand the effect of those arrangements on its financial position. This pronouncement was issued to facilitate comparison between financial statements prepared on the basis of GAAP and IFRS. This update is effective for annual and interim reporting periods beginning on or after January 1, 2013 and is to be applied retroactively for all comparative periods presented. The adoption of ASU 2011-11 is not expected to have a significant impact on the Company s financial position or results of operations.

2. RECAPITALIZATION

On December 21, 2011, the Company entered into a Securities Purchase Agreement (the Purchase Agreement) with HALRES LLC (formerly, Halcón Resources, LLC). Pursuant to the Purchase Agreement, (i) HALRES LLC purchased and the Company sold 73,333,333 shares of the Company s common stock (the Shares) for a purchase price of $275,000,000 and (ii) HALRES LLC purchased and the Company issued a senior convertible promissory note in the principal amount of $275,000,000 (the 8% Note), together with five year warrants (the February 2012 Warrants) to purchase 36,666,666 shares of the Company s common stock at an exercise price of $4.50 per share, subject to adjustment under certain circumstances. The 8% Note is convertible after February 8, 2014 into 61,111,111 shares of common stock at a conversion price of $4.50 per share, subject to adjustment under certain circumstances. The Company and HALRES LLC closed the transaction contemplated by the Purchase Agreement on February 8, 2012 (the Closing).

During January 2012, shareholders holding a majority of the Company s outstanding shares of common stock approved the issuance of the Shares, the 8% Note and the February 2012 Warrants pursuant to the terms of the Purchase Agreement. Additionally, the Board of Directors approved, effective upon the Closing (i) the amendment of the Company s certificate of incorporation to (A) increase the Company s authorized shares of common stock from 100,000,000 shares to 1,010,000,000 shares, both of which are before the one-for-three reverse stock split; (B) a one-for-three reverse stock split of the Company s common stock (which reduced the Company s authorized shares of common stock from 1,010,000,000 to 336,666,666 shares); and (C) a name change from RAM Energy Resources, Inc. to Halcón Resources Corporation; (ii) the amendment of the Company s 2006 Long-Term Incentive Plan (the Plan) to increase the number of shares that may be issued under the Plan from 2,466,666 to 3,700,000 shares; and (iii) on an advisory (non-binding) basis, the payments made to the Company s named executive officers in connection with the transactions contemplated by the Purchase Agreement.

The Closing of the transaction resulted in a change in control of the Company. Material events and items resulting from the transaction include the following:

- completion of transactions contemplated by the Purchase Agreement and shareholder approval as discussed above;

- the resignation and termination of the Company s four executive officers and the resignation of certain other officers;

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- change in control payments of $4.6 million to the officers of the Company recorded in general and administrative expense;

- change in control payment of $0.8 million pursuant to a retainer agreement with the Company s outside law firm recorded in general and administrative expense;

- accelerated vesting of all unvested employee restricted stock shares and accelerated vesting and exercise of all unvested stock appreciation rights resulting in $4.3 million of share-based compensation expense recorded in general and administrative expense;

- payoff and termination of the Company s revolving credit facility of $133.0 million plus accrued interest, as well as the expensing of the related unamortized debt issue costs of $2.9 million;

- payoff and termination of the Company s second lien term facility of $75.0 million plus accrued interest and a prepayment fee of $1.5 million, as well as the expensing of the related unamortized debt issue costs of $2.9 million; and

- closing costs of $11.2 million related to engagement fees and various professional fees including $2.5 million recorded in general and administrative expense related to a termination fee pursuant to a previous engagement.

During January 2012, the Company approved a one-for-three reverse stock split, which was implemented on February 10, 2012. Retroactive application of the reverse stock split is required and all share and per share information included for all periods presented in these financial statements reflects the reverse stock split.

During February 2012, the transaction with HALRES LLC resulted in an ownership change as defined under Section 382 of the Internal Revenue Code. As a consequence, the Company will have additional limitations on its ability to use the net operating losses it accrued before the change-in-control as a deduction against any taxable income the Company realizes after the change-in-control.

3. RESTRUCTURING

During March 2012, the Company announced its intention to close the Plano, Texas office and begin the process of relocating key administrative functions to Houston, Texas (the Restructuring). As part of the Restructuring, the Company offered certain severance and retention benefits (collectively, the Severance Program) to the affected employees. The estimated total expense of the Severance Program is approximately $3.2 million and related costs will be recognized as restructuring expense over the requisite service periods through May 2013, as applicable. The Company recorded a restructuring liability of $0.1 million as of March 31, 2012. During the subsequent six month period ended September 30, 2012, the Company increased the restructuring liability by an additional $1.7 million to reflect the accrual of expense over the requisite period and decreased the liability by $0.3 million for actual expenditures, resulting in a liability of $1.5 million at September 30, 2012.

4. ACQUISITIONS

GeoResources, Inc.

On August 1, 2012, the Company completed an acquisition of GeoResources, Inc. (GeoResources or GEOI) by means of the merger of a wholly-owned subsidiary of the Company with and into GeoResources (the Merger). In connection with the Merger, each share of GeoResources common stock issued and outstanding immediately prior to the effective time of the Merger was converted into the right to receive $20.00 in cash and 1.932 shares of the Company s common stock. All outstanding options to purchase GeoResources common stock were exercised immediately prior to the effective time of the Merger on a net cashless basis. All outstanding GeoResources restricted stock units vested and were settled in shares of GeoResources common stock immediately prior to the effective time of the Merger. All outstanding warrants to purchase GeoResources common stock were assumed by the Company and converted into warrants (the August 2012 Warrants) to acquire equivalent Merger consideration.

In connection with the consummation of the Merger, the Company issued a total of approximately 51.3 million shares of its common stock and paid approximately $531.5 million in cash to former GeoResources stockholders in exchange for their shares of GeoResources common stock. The acquisition expanded the Company s presence in the Bakken/Three Forks trends of North Dakota and Eastern Montana as well as adding properties in Texas, Oklahoma, and Louisiana, adding oil and natural gas reserves and production to its existing asset base in these areas.

The acquisition was accounted for as a business combination in accordance with Accounting Standards Codification (ASC) No. 805 *Business Combinations* (ASC 805) which, among other things, requires assets acquired and liabilities assumed to be measured at their acquisition date fair values.

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The purchase price allocation presented below is preliminary and includes the use of estimates. This preliminary allocation is based on information that was available to management at the time these unaudited condensed consolidated financial statements were prepared. The Company believes the estimates used are reasonable and the significant effects of the Merger are properly reflected. However, the estimates are subject to change as additional information becomes available and is assessed by the Company. Changes to the purchase price allocation may result in a corresponding change to the goodwill in the period of change. The following table summarizes the consideration paid to acquire GeoResources and the estimated values of assets acquired and liabilities assumed in the accompanying unaudited condensed consolidated balance sheets as of August 1, 2012 (in thousands, except stock price):

Purchase price *(i)*		
Shares of Halcón common stock issued to GeoResources stockholders		50,378
Shares of Halcón common stock issued to GeoResources stock option holders		966
Total Halcón common stock issued		51,344
Halcón common stock price	$	6.26
Fair value of common stock issued	$	321,416
Cash consideration paid to GeoResources stockholders *(ii)*		521,526
Cash consideration paid to GeoResources stock option holders *(ii)*		9,996
Fair value of warrants assumed by Halcón *(v)*		1,474
Total purchase price	$	854,412
Estimated fair value of liabilities assumed:		
Current liabilities	$	112,641
Deferred tax liability *(iii)*		238,882
Asset retirement obligations		9,320
Other non-current liabilities		80,024
Amount attributable to liabilities assumed	$	440,867
Total purchase price plus liabilities assumed	$	1,295,279
Estimated fair value of assets acquired:		
Current assets	$	122,528
Evaluated oil and natural gas properties *(iv)(vi)*		542,820
Unevaluated oil and natural gas properties *(vi)*		455,000
Net other operating property and equipment		1,179
Equity in oil and gas partnerships		11,189
Other non-current assets		1,645
Amount attributable to assets acquired	$	1,134,361
Goodwill	$	160,918

(i) Under the terms of the merger agreement, consideration paid by Halcón consisted of $20.00 in cash plus 1.932 shares of Halcón common stock for each share of GeoResources common stock. The total purchase price was based upon the price of Halcón common stock on the closing date of the transaction, August 1, 2012, and approximately 26.6 million shares of GeoResources common stock outstanding at the effective time of the Merger. The Company issued a total of 51.3 million shares of its common stock and paid $531.5 million in cash to former GeoResources stockholders in exchange for their shares of GEOI common stock.

(ii) Components of cash flow for GeoResources Merger (in thousands):

Total cash consideration for Merger and stock options (1)	$	531,522
Retirement of GeoResources long-term debt (2)		80,328
Cash acquired on date of Merger		(32,353)
Total cash outflows, net	$	579,497

(1) The majority of the cash consideration was funded by the net proceeds from the 9.75% senior notes.

(2) Includes accrued interest and fees.

(iii) Halcón received carryover tax basis in GeoResources assets and liabilities because the Merger was not a taxable transaction under

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the United States Internal Revenue Code of 1986, as amended (the Code). Based upon the purchase price allocation, a step-up in financial reporting carrying value related to the property acquired from GeoResources resulted in a Halcón deferred tax liability of approximately $238.9 million, an increase of approximately $177.5 million to GeoResources existing $61.4 million deferred tax liability.

(iv) Weighted average commodity prices utilized in the determination of the fair value of oil and natural gas properties was $5.40 per Mcf of natural gas, $55.11 per barrel of oil equivalent for NGLs and $95.22 per barrel of oil, after adjustment for transportation fees and regional price differentials.

(v) The $1.5 million fair value of the assumed warrants was calculated using a Black-Scholes valuation model with assumptions for the following variables: price of Halcón stock on the closing date of the merger; risk-free interest rates; and expected volatility. The assumed warrants have been classified as liabilities as the warrant holders can receive cash. The assumed warrants are classified as current liabilities under the assumption that all assumed warrants will be held to maturity date that is within 12 months from September 30, 2012.

(vi) The market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount for future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates used by the Company to estimate the fair value of the oil and natural gas properties represent Level 3 inputs. For additional information on Level 3 inputs, see Note 8 *Fair Value Measurements* .

East Texas Assets

Between August 1, 2012 and August 3, 2012, the Company completed the acquisition of a total of 20,628 net acres of oil and gas leaseholds in East Texas (the East Texas Assets) from CH4 Energy II, LLC, PetroMax Leon, LLC, Petro Texas LLC, King King LLC and several other selling parties for total consideration of $432.2 million comprised of $301.6 million in cash and 20.8 million shares of the Company s common stock (East Texas Acquisition). The East Texas Acquisition expanded the Company s presence in East Texas, adding oil and natural gas reserves and production to its existing asset base in this area. On August 27, 2012 the Company filed a registration statement with the SEC that registers under the Securities Act the resale of the shares of common stock issued as consideration in the East Texas Acquisition. In accordance with the purchase agreement, the effective date of the acquisition was April 1, 2012 and therefore revenues, expenses and related capital expenditures from April 1, 2012 through the closing of the East Texas Acquisition have been reflected as part of the purchase accounting and subsequent to closing of the transaction have resulted in an additional reduction of $5.4 million to the purchase price.

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The East Texas Acquisition was accounted for as a business combination in accordance with ASC 805 which, among other things, requires assets acquired and liabilities assumed to be measured at their acquisition date fair values. No goodwill was recorded in connection with the acquisition. The purchase price allocation is preliminary and subject to adjustment as additional information becomes available and is assessed by the Company. The following table summarizes the consideration paid to acquire the properties and the amounts of the assets acquired and liabilities assumed as of the acquisition date (in thousands, except stock prices):

Purchase price *(i)*:		
Shares of Halcón common stock issued on 08/01/12		16,460
Shares of Halcón common stock issued on 08/02/12		4,310
Total Halcón common stock issued		20,770
Halcón common stock price on 08/01/12	$	6.26
Halcón common stock price on 08/02/12	$	6.40
Fair value of Halcón common stock issued	$	130,623
Cash consideration paid to sellers of East Texas Assets *(iii)*		301,569
Total purchase price *(iii)*	$	432,192
Estimated fair value of liabilities assumed:		
Asset retirement obligations	$	337
Amount attributable to liabilities assumed	$	337
Total purchase price plus liabilities assumed	$	432,529
Estimated fair value of assets acquired *(iv)*:		
Evaluated oil and natural gas properties *(ii)*	$	334,080
Unevaluated oil and natural gas properties		98,449
Amount attributable to assets acquired	$	432,529
Goodwill	$	

(i) Based on the terms of the purchase and sale agreements relating to the East Texas Assets, consideration paid by Halcón at closing consisted of $301.6 million in cash plus 20.8 million shares of Halcón common stock. The total purchase price is based upon the price on August 1, 2012 of $6.26 per share of Halcón s common stock for CH4 Energy, Petro Texas and Petromax Leon (Initial Sellers) and price on August 2, 2012 of $6.40 per share of Halcón s common stock for King King USA.

(ii) Weighted average commodity prices utilized in the determination of the fair value of oil and natural gas properties were $5.10 per Mcf of natural gas, $49.72 per barrel of oil equivalent for NGLs and $96.56 per barrel of oil, after adjustment for transportation fees and regional price differentials.

(iii) Subsequent to the acquisition date the Company recorded $5.4 million in post-closing adjustments reducing the total purchase price and cash consideration paid to $426,762 and $296,139, respectively at September 30, 2012.

(iv) The market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount for future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates used by the Company to estimate the fair value of the oil and natural gas properties represent Level 3 inputs. For

additional information on Level 3 inputs, see Note 8 *Fair Value Measurements* .

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The following unaudited pro forma combined results of operations are provided for the nine-month periods ended September 30, 2012 and September 30, 2011 as though the GeoResources and East Texas Assets acquisitions had been completed as of the beginning of the earliest period presented, or January 1, 2011. The pro forma combined results of operations for the nine-month periods ended September 30, 2012 and 2011 have been prepared by adjusting the historical results of the Company to include the historical results of GeoResources and East Texas Assets. These supplemental pro forma results of operations are provided for illustrative purposes only and do not purport to be indicative of the actual results that would have been achieved by the combined company for the periods presented or that may be achieved by the combined company in the future. The pro forma results of operations do not include any cost savings or other synergies that resulted, or may result, from the GeoResources and East Texas Assets acquisitions or any estimated costs that will be incurred to integrate GeoResources and the East Texas Assets. Future results may vary significantly from the results reflected in this pro forma financial information because of future events and transactions, as well as other factors.

	Nine months ended September 30, (in thousands, except per share amounts)			
		2012		2011
Revenue	$	291,272	$	184,511
Net loss	$	(13,375)	$	(3,873)
Loss available to Halcón common stockholders	$	(101,820)	$	(3,786)
Pro forma net loss per common share				
Basic	$	(0.54)	$	(0.03)
Diluted	$	(0.54)	$	(0.03)

For the three and nine month periods ended September 30, 2012, the Company recognized $33.9 million of oil, natural gas and natural gas liquids sales and $25.9 million of net field operating income (oil, natural gas and natural gas liquids sales less lease operating expenses, workover expenses and production taxes) related to properties acquired in the GeoResources Merger. Additionally, non-recurring transaction costs of $16.1 million and $19.4 million related to the GeoResources Merger for the three and nine month periods ended September 30, 2012, respectively, are included in the consolidated statement of operations as general and administrative expenses; these non-recurring transaction costs have been excluded from the pro forma results in the above table.

For the three and nine month periods September 30, 2012, the Company recognized $15.1 million of oil, natural gas and natural gas liquids sales related to properties acquired in the East Texas Acquisition and $13.0 million of net field operating income (oil, natural gas and natural gas liquids sales less lease operating expenses, workover expenses and production taxes expenses) related to properties acquired in the East Texas Acquisition. Additionally, non-recurring transaction costs of $0.7 million and $1.1 million related to the East Texas Acquisition for the three and nine month periods ended September 30, 2012, respectively, are included in the consolidated statement of operations as general and administrative expenses; these non-recurring transaction costs have been excluded from the pro forma results in the above table.

The acquisitions of GeoResources and the East Texas Assets were partially financed with the net proceeds from the issuance of $750.0 million of 9.75% senior unsecured notes and cash on hand.

Unevaluated Properties

On June 28, 2012, the Company completed the acquisition of acreage in Eastern Ohio, believed to be prospective for the Utica/Point Pleasant formations. Pursuant to the terms of an Agreement of Sale and Purchase dated May 8, 2012 with NCL Appalachian Partners, L.P. (NCL), the Company acquired a working interest in approximately 27,000 net acres for an adjusted purchase price of approximately $164.0 million. The Company funded the acquisition with cash on hand. No oil or natural gas production or proved reserves are currently attributable to the acquired assets.

In addition to the NCL, GeoResources, and East Texas Asset acquisitions, during 2012 the Company incurred approximately $403.2 million in capital expenditures on unevaluated oil and gas leaseholds through numerous leasing and acquisition transactions. No oil or natural gas production or proved reserves were attributable to the acquired unevaluated leasehold assets which were primarily located in Texas, Louisiana, Ohio and Pennsylvania.

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5. 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 an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

Investments in unevaluated oil and 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 our condensed consolidated balance sheet. 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 three and nine months ended September 30, 2012, the Company capitalized interest costs of $19.4 million and $22.8 million, respectively. During the three and nine month periods ended September 30, 2011 the Company did not capitalize any interest costs.

At September 30, 2012 the ceiling test value of the Company s reserves was calculated based on the first day average of the 12-months ended September 30, 2012 of the West Texas Intermediate (WTI) spot price of $94.97 per barrel, adjusted by lease or field for quality, transportation fees, and regional price differentials, and the first day average of the 12-months ended September 30, 2012 of the Henry Hub price of $2.83 per million British thermal units (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, 2012, did not exceed the ceiling amount. Changes in production rates, levels of reserves, future development costs, and other factors will determine the Company s actual ceiling test calculation and impairment analyses in future periods.

At September 30, 2011 the ceiling test value of the Company s reserves was calculated based on the first day average of the 12-months ended September 30, 2011 of the WTI posted price of $94.50 per barrel, adjusted by lease or field for quality, transportation fees, and regional price differentials, and the first day average of the 12-months ended September 30, 2011 of the Henry Hub price of $4.16 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, 2011, did not exceed the ceiling amount.

6. LONG-TERM DEBT

Long-term debt as of September 30, 2012 and December 31, 2011 consisted of the following (in thousands):

		September 30, 2012		December 31, 2011
8% Note (1)	$	249,979	$	
9.75% Senior Notes (2)		740,021		
Revolving credit facility		185,000		127,000
Term loan facility				75,000
	$	1,175,000	$	202,000

(1) Amount is net of a $39.7 million unamortized discount at September 30, 2012. See 8% Note below for more details.

(2) Amount is net of a $10.0 million unamortized discount at September 30, 2012. See 9.75% Senior Notes below for more details.

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8% Note

On February 8, 2012, the Company issued the 8% Note in the principal amount of $275.0 million together with the February 2012 Warrants for an aggregate purchase price of $275.0 million. The 8% 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. Through the March 31, 2014 interest payment date, the Company may elect to pay-in-kind, by adding to the principal of the 8% Note, all or any portion of the interest due on the 8% Note. At September 30, 2012, June 30, 2012 and March 31, 2012, the Company elected to pay in-kind $5.8 million, $5.7 and $3.2 million, respectively, of interest incurred during the first nine months of 2012. The 8% Note matures on February 8, 2017. At any time after February 8, 2014, the noteholder may elect to convert all or any portion of the principal amount and accrued but unpaid interest into common stock. Each $4.50 of principal and accrued but unpaid interest is convertible into one share of the Company s common stock. The 8% Note is a senior unsecured obligation of the Company.

The Company allocated the proceeds received for the 8% 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 8% Note utilizing the effective interest rate method. The remaining unamortized discount was $39.7 million at September 30, 2012.

9.75% Senior Notes

On July 16, 2012, the Company completed a private offering of $750.0 million aggregate principal amount of 9.75% senior unsecured notes due 2020 (the 9.75% Notes), issued at 98.646% of par. 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 GeoResources Merger and the East Texas Assets acquisition.

In connection with the issuance of the 9.75% Notes, the Company recorded a discount of approximately $10.2 million to be amortized over the remaining life of the 9.75% Notes using the effective interest method. The remaining unamortized discount was $10.0 million at September 30, 2012.

Credit Facility

February 2012 Credit Facility Amendment The Company s borrowing base under the February 2012 credit facility was redetermined upon the completion of the GeoResources Merger and East Texas Assets acquisition. On August 1, 2012, the Company entered into the First Amendment to the senior revolving credit agreement (the First Amendment). The First Amendment increased the commitments under the revolving credit facility to an aggregate amount up to $1.5 billion and the borrowing base from $225.0 million to $525.0 million. The First Amendment also modified limitations on the Company s commodity hedging program to allow the Company to hedge up to 85% of its projected proved production forecast for 66 months following the date a commodity hedging agreement is executed. See Note 16 Subsequent Events for additional discussion regarding enhancements to the Credit Facility related to the pending acquisition of the Williston Basin Assets.

February 2012 Credit Facility On February 8, 2012, the Company entered into the February 2012 Credit Facility a $500.0 million, five-year, senior secured revolving credit agreement with JPMorgan Chase Bank, N.A. (JPMorgan) as the administrative agent and lead arranger, which replaced the Company s March 2011 credit facility. The agreement increased the revolving borrowing base to $225.0 million and matures on February 8, 2017. The borrowing base will be redetermined semi-annually, with the Company and the lenders each having the right to one interim unscheduled redetermination between any two consecutive semi-annual redeterminations. 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 revolving credit agreement may be paid down and re-borrowed during the five-year term of the revolver. The pricing on the agreement is LIBOR plus a margin ranging from 1.5% to 2.5% based on a percentage of usage. Advances under the revolving credit agreement are secured by liens on substantially all properties and assets of the Company and its subsidiaries. The revolving credit agreement contains representations, warranties and covenants customary in transactions of this nature including restrictions on the payment of dividends on the Company s capital stock and financial covenants relating to current ratio and minimum interest coverage ratio. The Company maintains commodity hedges of not more than 85% of its projected proved production forecast. At September 30, 2012, the Company is in compliance with the financial debt covenants under this agreement. At September 30, 2012, the Company had $185.0 million indebtedness outstanding, $1.3 million of letters of credit outstanding and $338.7 million of borrowing capacity available under the revolving credit agreement.

March 2011 Credit Facilities - The Company s March 2011 facilities included a $250.0 million first lien revolving credit facility and a $75.0 million second lien term loan facility, replacing the November 2007 facility. SunTrust Bank was the administrative agent for the

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revolving facility, and Guggenheim Corporate Funding, LLC was the administrative agent for the term loan facility. The initial borrowing base under the revolving credit facility was $150.0 million. This revolving credit facility allowed for funds advanced to be paid down and re-borrowed during the five-year term of the revolver, and bore interest at LIBOR plus a margin ranging from 2.5% to 3.25% based on a percentage of usage. The term loan credit facility provided for payments of interest only during its 5.5-year term, with the interest rate being LIBOR plus 9.0% with a 2.0% LIBOR floor, or if any period the Company elected to pay a portion of the interest under its term loan in kind , then the interest rate would have been LIBOR plus 10.0% with a 2.0% LIBOR floor, and with 7.0% of the interest amount paid in cash and the remaining 3.0% paid in kind by being added to principal. At December 31, 2011, $127.0 million was outstanding under the revolving credit facility and $75.0 million was outstanding under the term loan credit facility. On February 8, 2012, the Company paid in full the outstanding balances under the revolving credit facility and the term loan facility and both facilities were terminated, with a resulting $1.5 million charge to interest expense related to an early termination penalty.

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 2012, the Company capitalized approximately $3.3 million, $4.4 million, and $16.8 million in costs associated with the issuance of the 8% Note, February 2012 credit facility and 9.75% Notes, respectively. During February 2012, the Company expensed $5.8 million of debt issuance costs as a result of the pay off and termination of the March 2011 revolving credit and term loan facilities. The Company expensed the remaining debt issuance cost associated with the November 2007 facility totaling approximately $2.7 million in the first quarter 2011. At September 30, 2012 and December 31, 2011, the Company had approximately $23.5 million and $6.0 million, respectively, of unamortized debt issuance costs.

7. INCOME TAXES

Under guidance contained in Topic 740 of the ASC, 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.

The Company estimates its annual effective income tax rate in recording its quarterly provision for income taxes in the various jurisdictions in which the Company operates. Statutory tax rate changes and other significant or unusual items are recognized as discrete items in the quarter in which they occur. During the three and nine months ended September 30, 2012 and 2011, the Company analyzed and made no adjustment to the valuation allowance.

The provision for income taxes differs from the amount computed by applying the statutory federal income tax rate to income before provision for income taxes. The significant differences between pre-tax book income and taxable book income relate to non-deductible expenses, state income taxes, change in valuation allowances, Section 382 net operating loss limitations and other adjustments to deferred tax balances. The sources and tax rates of the differences for the nine months ended September 30 are as follow:

	2012	2011

Income tax at the federal statutory rate	34.0%	34.0%
State income tax, net of federal tax	1.4	6.7
Non-deductible dues and entertainment	(0.5)	0.5
Non-deductible interest and expense on 8% Note	(12.5)	
(Reduction) increase in deferred tax asset	(2.0)	9.8
Share-based compensation	(1.3)	
Non-deductible compensation		0.1
Non-deductible basis in other operating property and equipment	(0.7)	
Non-deductible stock warrants	(0.9)	
Non-deductible Merger costs	(20.1)	
	(2.6)%	51.1%

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The Company has calculated an estimated effective annual tax rate for the current annual reporting period, excluding any discrete items, of a negative 0.6% as of September 30, 2012. Additionally, the Company recorded a discrete item of $0.9 million relating to a $1.0 million benefit for return to provision and a $1.9 million expense for a reduction in net operating losses due to additional limitations created by a change in control prior to the recapitalization of the Company in February 2012. The recapitalization created an ownership change of the Company in February 2012 and as a result the net operating losses of the Company may be subject to additional limitations. The discrete items decrease the effective tax rate to a negative tax rate of 2.6%. The estimated annual effective tax rate differs from the statutory rate primarily due to non-deductible interest expense on the 8% Note issued as part of the recapitalization of the Company and non-deductible Merger costs associated with the acquisition of GeoResources. Based on the estimated effective annual tax rate, the Company has recorded a tax provision of $0.3 million plus $0.9 million of discrete items for a total income tax expense of $1.2 million on a pre-tax loss of $44.7 million for the nine months ended September 30, 2012. For the nine months ended September 30, 2011, the Company recorded income tax expense of $11.3 million on a pre-tax income of $22.1 million, resulting in an effective tax rate of 51.1%.

For the nine months ended September 30, 2012 the Company has net operating losses of $58.1 million that are not expected to be limited due to the limitations created by the ownership change on February 8, 2012.

8. FAIR VALUE MEASUREMENTS

Pursuant to, *Fair Value Measurements and Disclosures* (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, 2012 and December 31, 2011 (in thousands). 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, 2012 and for the year ended December 31, 2011.

	September 30, 2012			
	Level 1	**Level 2**	**Level 3**	**Total**
Assets:				
Receivables from derivative contracts	$	$ 5,347	$	$ 5,347
Liabilities:				
Liabilities from derivative contracts	$	$ 1,908	$	$ 1,908

Liabilities from warrants				2,002				2,002
Total Liabilities	$		$	3,910	$		$	3,910

	December 31, 2011							
	Level 1		**Level 2**		**Level 3**		**Total**	
Assets:								
Receivables from derivative contracts	$		$	260	$		$	260
Liabilities:								
Liabilities from derivative contracts	$		$	1,070	$		$	1,070

Derivatives listed above consist of put/call collars and sold put options on crude oil and natural gas and interest rate swaps 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.

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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 11 for addition discussion of derivatives.

As of September 30, 2012 and December 31, 2011, 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 discussed above; however, the Company does not anticipate such nonperformance. The counterparties to the Company s current derivative contracts are lenders in the Company s senior revolving credit agreement. The Company did not post collateral under any of these contracts as they are secured under the senior revolving credit agreement.

Warrants listed above are carried at fair value. The Company records the net change in fair value on the August 2012 Warrants in Other Expense which is included in *Interest Expense and other, net* in the Company s unaudited condensed consolidated statements of operations. During the three and nine months ended September 30, 2012 an unrealized loss of $0.5 million was recorded to reflect the change in fair value. The Company valued the August 2012 Warrants based on observable market data, including treasury rates, historical volatility and data for similar instruments which resulted in the Company reporting its warrants as Level 2. See Note 12 *August 2012 Warrants* for additional discussion on the terms of the warrants.

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 revolving credit agreement approximates carrying value because the facility s interest rate approximates current market rates. The estimated fair value of the Company s fixed interest rate 8% Note as of September 30, 2012, is $639.6 million and exceeded the carrying value of $250.0 million by $389.6 million. The estimated fair value of the Company s fixed interest rate 9.75% Notes as of September 30, 2012, is $760.4 million and exceeded the carrying value of $740.0 million by $20.4 million. The fair value of the 8% Note and the 9.75% Notes at September 30, 2012 was calculated using Level 2 and Level 3 criteria, respectively. The fair value of the 9.75% Notes was calculated using a Black-Derman-Toy model consistent with the issuance price of the 9.75% Notes. The significant unobservable input used in the Company s Level 3 fair value measurement at September 30, 2012 is included in the table below:

Liability	**Unobservable Input**	**Basis Point Spread**	**Fair Value (in millions)**
9.75% Notes	Estimated implied option adjusted spread over risk-free rate curve	834	$ 760.4(1)

(1) A 10% increase in the basis point spread to 917 would decrease the fair value of the 9.75% Notes to $729.2 million and a 10% decrease in the basis point spread to 750 would increase the fair value of the 9.75% Notes to $792.4 million.

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9. ASSET RETIREMENT OBLIGATIONS

For wells drilled, the Company records an asset retirement obligation (ARO) when the total depth of a drilled well is reached and the Company can reasonably estimate the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon costs. The Company records the ARO liability on the unaudited condensed consolidated balance sheets and capitalizes the cost in *Oil and natural gas properties* 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.

The Company recorded the following activity related to its ARO liability for the nine months ended September 30, 2012 (in thousands):

Liability for asset retirement obligations as of December 31, 2011	$	33,713
Liabilities settled		(534)
Additions (1)		10,016
Accretion expense		1,424
Liability for asset retirement obligations as of September 30, 2012		44,619
Less: current asset retirement obligations		1,968
Long-term asset retirement obligations	$	42,651

(1) Includes additions of $9.3 million and $0.3 million related to the GeoResources and the East Texas Assets acquisitions, respectively. Please see Note 4, Acquisitions for additional information.

10. COMMITMENTS AND CONTINGENCIES

Commitments

The Company leases corporate office space in Houston and Plano, Texas; Tulsa, Oklahoma; Denver, Colorado; and Williston, North Dakota as well as a number of other field office locations. In addition, the Company has lease commitments for certain equipment under long-term operating lease agreements. The office and equipment operating lease agreements expire on various dates through 2020. Rent expense was approximately $2.2 million and $1.0 million for the nine months ended September 30, 2012 and 2011, respectively. Approximate future minimum lease payments for the remainder of 2012 and subsequent annual periods for all non-cancelable operating leases at September 30, 2012 are as follows (in thousands):

2012	$	1,567
2013		6,226
2014		5,306
2015		5,160
2016 and thereafter		23,196

	$	41,455

The Company is also obligated under contracts for drilling rigs and related equipment for its drilling operations as followings (in thousands):

2012	$	22,061
2013		20,858
2014		10,038
2015		4,978
2016 and thereafter		
	$	57,935

As of September 30, 2012, early termination of the drilling rigs and related equipment contracts would require termination penalties of $38.5 million, which would be in lieu of paying the remaining drilling commitments of $57.9 million.

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The Company also has non-cancelable purchase commitments for pipe, storage tanks and production equipment in the amount of $5.9 million.

The Company has committed to one long-term natural gas sales contract in its Williams County North Dakota project area in the Bakken trend. Under the terms of this contract the Company has committed substantially all of the natural gas production for the life of its leases to one purchaser. In return for the life of lease commitment, the purchaser has committed to building a gas gathering system across the Company s project area. The sales price under this contract is based on a posted market rate.

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.

11. DERIVATIVES

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, natural gas and natural gas liquids production. The Company generally hedges a substantial, but varying, portion of anticipated oil and natural gas production for future periods. Currently the Company has hedges in place for periods through June 2014. During 2010, 2011 and 2012, the Company entered into numerous derivative contracts and did not designate these transactions as hedges for accounting purposes. 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.

During February 2012, pursuant to the February 2012 senior secured revolving credit agreement, the Company novated its oil and natural gas derivative instruments to counterparties that are lenders within the new senior secured revolving credit agreement resulting in a realized loss of $0.4 million for novation fees and terminated the interest rate derivatives resulting in a $0.6 million realized loss.

It is the Company s policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The counterparties to the Company s current derivative contracts are lenders in the Company s senior revolving credit agreement. The Company did not post collateral under any of these contracts as they are secured under the Company s senior secured revolving credit agreement.

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The Company s crude oil and natural gas derivative positions at September 30, 2012 consist of swaps, put/call collars and sold 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 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. 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. 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, 2012 and December 31, 2011 (in thousands):

Derivatives not designated as hedging contracts	**Balance sheet location**	**Asset derivative contracts Sept. 30, 2012**	**Asset derivative contracts Dec. 31, 2011**	**Liability derivative contracts Sept. 30, 2012**	**Liability derivative contracts Dec. 31, 2011**	**Netted derivative contracts Sept. 30, 2012**	**Netted derivative contracts Dec. 31, 2011**
Commodity contracts	Current assets - receivables from derivative contracts	$ 5,050	$ 1,850	$ (726)	$ (1,590)	$ 4,324	$ 260
Commodity contracts	Other noncurrent assets - receivables from derivative contracts	1,047		(24)		1,023	
Commodity contracts	Current liabilities - liabilities from derivative contracts	1,960		(3,614)		(1,654)	
Commodity contracts	Other noncurrent liabilities - liabilities from derivative contracts	863	2,050	(1,117)	(2,602)	(254)	(552)
Interest rate swaps	Current liabilities - liabilities from derivative contracts				(265)		(265)
Interest rate swaps	Other noncurrent liabilities - liabilities from derivative contracts				(253)		(253)
Total derivatives not designated as hedging contracts		$ 8,920	$ 3,900	$ (5,481)	$ (4,710)	$ 3,439	$ (810)

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The types of derivative contracts and related realized and unrealized gains and losses illustrated in the following table are located in *Other income (expenses) Net gain (loss) on derivative contracts* in the Company s unaudited condensed consolidated statements of operations (in thousands):

	Amount of gain (loss) recognized on derivative contracts for the:			
	Three months ended September 30,		Nine months ended September 30,	
Derivatives not designated as hedging contracts	**2012**	**2011**	**2012**	**2011**
Unrealized gain (loss) on commodity contracts	$ (11,817)	$ 22,744	$ (4,641)	$ 18,519
Realized gain (loss) on commodity contracts	2,242	76	3,850	(1,186)
Unrealized gain (loss) on interest rate swaps		(138)	518	(556)
Realized loss on interest rate swaps		(65)	(576)	(142)
Total net gain (loss) on derivative contracts	$ (9,575)	$ 22,617	$ (849)	$ 16,635

At September 30, 2012, the Company had the following open derivatives contracts:

				September 30, 2012					
				Floors		Ceilings		Put Options Sold	
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**
October 2012 - December 2012	3 Way-collars	Crude oil	103,500	$90.00 - $95.00	$ 92.78	$101.70 - $107.00	$ 104.13	$ 70.00	$ 70.00
October 2012 - December 2012	Collars	Crude oil	409,500	85.00 - 95.00	89.49	98.00 - 110.00	100.91		
October 2012 - December 2012	Fixed Swap	Crude oil	165,000			86.85 - 108.45	98.62		
October 2012 - December 2012	Fixed Swap	Natural gas	435,000			2.925 - 6.415	5.12		
October 2012 - December 2012	Basis Swap	Natural gas	375,000						
January 2013 - June 2013	3 Way-collars	Crude oil	251,075	95.00 - 100.00	95.18	99.50 - 109.50	100.60	70.00	70.00
January 2013 - December 2013	Collars	Crude oil	2,267,125	80.00 - 95.00	87.35	92.70 - 101.50	96.59		
January 2013 - December 2013	Fixed Swap	Crude oil	360,000			97.60 - 105.55	102.18		
January 2013 - December 2013	Fixed Swap	Natural gas	465,000			3.56 - 4.85	4.18		
January 2013 - March 2013	Basis Swap	Natural gas	225,000						
January 2014 - June 2014	3 Way-collars	Crude oil	280,500	95.00	95.00	98.20 - 109.50	99.59	70.00	70.00

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At December 31, 2011, the Company had the following open derivatives contracts (including interest rate swaps):

				December 31, 2011					
				Floors		Ceilings		Put Options Sold	
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 2012 - December 2012	3 Way-collars	Crude oil	400,500	$80.00 - $100.00	$ 87.15	$101.70 - $113.25	$ 104.89	$ 70.00	$ 70.00
January 2012 - December 2012	Collars	Crude oil	299,300	80.00 - 95.00	84.34	102.40 - 107.00	105.43		
January 2012 - March 2012	Put options	Natural gas	609,700	4.00 - 4.50	4.35				
April 2012 - September 2012	Collars	Natural gas	915,000	4.00	4.00	6.00	6.00		
January 2013 - June 2013	3 Way-collars	Crude oil	251,075	95.00 - 100.00	95.18	99.50 - 109.50	100.60	70.00	70.00
January 2013 - December 2013	Collars	Crude oil	350,875	95.00	95.00	99.00 - 101.50	100.04		
January 2014 - June 2014	3 Way-collars	Crude oil	280,500	95.00	95.00	98.20 - 109.50	99.59	70.00	70.00

		Interest Rate Swaps (1) (3)		
Year	Notional Amount (in thousands)	Fixed Rate	Counterparty Floating Rate (2)	Months Covered
2013	$ 50,000	2.51%	3 Month LIBOR	January December
2014	$ 50,000	2.51%	3 Month LIBOR	January March

(1) Settlement is paid to the Company if the counterparty floating exceeds the fixed rate and settlement is paid by the Company if the counterparty floating rate is below the fixed rate. Settlement is calculated as the difference in the fixed rate and the counterparty rate.

(2) Subject to minimum rate of 2%

(3) All outstanding interest rate swaps were terminated in conjunction with the recapitalization during February 2012.

12. STOCKHOLDERS EQUITY

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 stock options and restricted stock, to be recognized in the financial statements based on their fair values.

On May 8, 2006, the Company s stockholders first approved its 2006 Long-Term Incentive Plan (as amended, the Plan). The Company reserved a maximum of 800,000 shares of its common stock for issuances under the Plan. On May 8, 2008, the Plan was amended to increase the maximum authorized number of shares to be issued under the Plan from 800,000 to 2,000,000. On May 3, 2010, the Plan was amended to increase the maximum authorized number of shares to be issued under the Plan from 2,000,000 to 2,466,666. On February 8, 2012, as part of the recapitalization described in Note 2, the Plan was amended to increase the maximum authorized number of shares to be issued under the Plan from 2,466,666 to 3,700,000. On May 17, 2012, shareholders approved an amendment and restatement of the Plan to (i) increase the maximum number of shares to be issued under the Plan from 3,700,000 to 11,500,000; (ii) extend the effectiveness of the Plan for ten years from the date of approval; and (iii) amend various other provisions of the Plan. As of September 30, 2012 and December 31, 2011, a maximum of 7,299,651 and 491,450 shares of common stock, respectively, remained reserved for issuance under the Plan.

Stock Options

During the nine months ended September 30, 2012, the Company granted stock options under the Plan covering 1,983,333 shares of common stock to employees of the Company. The stock options have exercise prices ranging from $6.26 to $11.55 with a weighted average exercise price of $9.10. 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. During the three and nine months ended September 30, 2012, $0.9 million and $1.4 million, respectively, was recognized as compensation expense as a component of general and administrative expense. There were not any options outstanding during 2011 and therefore no expense was recognized for the three and nine months ended September 30, 2011. At September 30, 2012, the unrecognized compensation expense related to stock options totaled $5.9 million and will be recognized on the graded-vesting method over the requisite service periods.

Restricted Stock

During the nine months ended September 30, 2012, the Company granted 277,300 shares of restricted stock under the Plan to directors and employees of the Company. During the three and nine months ended September 30, 2012, the Company realized compensation expense of $0.5 million and $0.6 million, respectively, related to the restricted stock issued in 2012. At September 30, 2012, the Company had $2.0 million of unrecognized compensation expense related to non-vested restricted stock awards to be recognized over a weighted-average period of two years. Additionally, during the nine months ended September 30, 2012, the

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Company realized compensation expense of $2.6 million primarily from the accelerated vesting of all unvested employee restricted stock shares due to the change in control in the Company resulting from the recapitalization as described in Note 2.

At September 30, 2011, the Company had $3.8 million of unrecognized compensation expense related to non-vested restricted stock awards to be recognized over a weighted-average period of two years. The related compensation expense recognized during the three and nine months ended September 30, 2011 was $0.9 million and $2.5 million, respectively. During the three and nine months ended September 30, 2011, the Company recorded $0.7 million and $2.1 million, respectively, as compensation expense and $0.2 million and $0.4 million, respectively, as capitalized internal costs.

Stock Appreciation Rights

During February 2012, the Company accelerated vesting and exercise of all unvested stock appreciation rights under the Plan (SARs) that were granted in May 2011, due to the change in control of the Company resulting from the recapitalization described in Note 2. The Company settled the SARs in cash, resulting in $2.2 million of share-based compensation expense recognized for the nine months ended September 30, 2012. The realized compensation expense was partially offset by the reversal of $0.8 million of unrealized losses recorded at December 31, 2011.

February 2012 Warrants

During February 2012, in conjunction with the issuance of the 8% Note, the Company issued February 2012 Warrants to purchase 36,666,666 shares of the Company s common stock at an exercise price of $4.50 per share pursuant to the recapitalization described in Note 2. 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.

August 2012 Warrants

During August 2012, as part of the merger transaction with GeoResources, the Company assumed outstanding GeoResources stock warrants. At the date of the merger 611,129 warrants were outstanding and converted to 1,180,706 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 and the right to receive $20 in cash per equivalent assumed share (Cash Portion) at an exercise price of $0.82 (Cash Exercise Price) per $1.00 received. The August 2012 Warrants will expire on June 9, 2013 and contain 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 from the Merger Agreement. These adjustments convert the terms to fundamentally equal what the warrant holders would have received had the warrants been exercised immediately prior to the close of the acquisition. Under the terms of the August 2012 Warrants, the warrant holder must exercise the Share Portion and the Cash Portion in tandem. The August 2012 Warrants are reflected as a current liability in the condensed consolidated balance sheets and at September 30, 2012 are recorded at fair value. Changes in fair value are recognized in *Interest expense and other, net.*

Common Stock

During January 2012, the Company approved a one-for-three reverse stock split, which was implemented on February 10, 2012. Retroactive application of the reverse stock split is required and all share and per share information included for all periods presented in these financial statements reflects the reverse stock split.

On February 8, 2012 pursuant to the closing of the recapitalization described in Note 2, the Company issued 73,333,333 shares of the Company s common stock for a purchase price of $275.0 million. Costs incurred of $4.0 million were netted against the proceeds of the common stock and recorded accordingly. In addition, the Company amended its certificate of incorporation to increase the Company s authorized shares of common stock from 33,333,333 shares to 336,666,666 shares.

During early August 2012, in connection with the Merger and the East Texas Acquisition, the Company issued 51,344,456 and 20,769,869 shares of common stock, respectively. The shares were issued at closing of the transactions as a portion of the consideration of the purchase price. See Note 4 for additional discussion on the issuance of common stock in connection with the acquisitions.

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Preferred Stock and Non-Cash Preferred Stock Dividend

On February 29, 2012 (the Commitment Date), the Company entered into definitive agreements with a group of certain institutional and selected other accredited investors (collectively, the investors) to sell, in a private offering, 4,444.4511 shares of 8% Automatically Convertible Preferred Stock, par value $0.0001 per share (the Preferred Stock), each share of which was convertible into 10,000 shares of common stock. Also on February 29, 2012, the Company received an executed written consent (the Consent) in lieu of a stockholders meeting authorizing and approving the conversion of the Preferred Stock into common stock. On March 2, 2012, the Company filed a Certificate of Designation, Preferences, Rights and Limitations of the Preferred Stock (the Certificate of Designation) with the Delaware Secretary of State which stated the conversion was to occur on the twentieth day after the mailing of a definitive information statement to stockholders. On March 5, 2012, the Company issued the Preferred Stock to the investors at $90,000 per share. Gross proceeds from the offering were approximately $400.0 million, or $9.00 per share of common stock, before offering expenses. The Company incurred placement agent fees of $14.0 million and associated expenses of approximately $0.5 million in connection with this offering. On March 28, 2012, the Company mailed a definitive information statement to its common stockholders notifying them that Halcón s majority stockholder had consented to the issuance of common stock, par value $0.0001, upon the conversion of the Preferred Stock. The Preferred Stock automatically converted into 44,444,511 shares of common stock on April 17, 2012 in accordance with the terms of the Certificate of Designation. No cash dividends were paid on the Preferred Stock since pursuant to the terms of the Certificate of Designation of the Preferred Stock, conversion occurred prior to May 31, 2012.

The Preferred Stock conversion feature was not considered a derivative instrument under ASC Topic 815 *Derivatives and Hedging* as it met the scope exception because the conversion feature is both indexed to the Company s own stock and classified in stockholders equity in the Company s balance sheet. However, in accordance with ASC 470 - *Debt* (ASC 470), the Company determined that the conversion feature in the Preferred Stock did represent a beneficial conversion feature. The fair value of the common stock of $10.99 on the Commitment Date was greater than the conversion price of $9.00 per common share, representing a beneficial conversion feature of $1.99 per common share, or $88.4 million in aggregate. Under ASC 470, $88.4 million (the intrinsic value of the beneficial conversion feature) of the proceeds received from the issuance of the Preferred Stock was allocated to additional paid-in capital, creating a discount on the Preferred Stock (the Discount). The Discount resulting from the allocation of value to the beneficial conversion feature was required to be amortized on a non-cash basis over the approximate 71 month period between the issuance date and the required redemption date of February 9, 2018, or fully amortized upon an accelerated date of redemption or conversion, and recorded as a preferred dividend. As a result, approximately $1.1 million of the Discount was amortized in the first quarter of 2012 and due to the conversion date occurring on April 17, 2012, the remaining $87.3 million of Discount amortization was accelerated to the conversion date and was fully amortized in the second quarter of 2012 as per the guidance of ASC 470. The Discount amortization is reflected as a non-cash preferred dividend in the condensed consolidated statements of operations. In accordance with the guidance in ASC 480, the preferred dividend was charged against additional paid-in capital since no retained earnings were available.

13. EARNINGS PER COMMON SHARE

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

	Three months ended September 30, 2012	Three months ended September 30, 2011	Nine months ended September 30, 2012	Nine months ended September 30, 2011
Basic				
Net income (loss) available to common stockholders	$ (20,181)	$ 11,776	$ (134,289)	$ 10,801
Weighted average basic number of common shares outstanding	191,846	26,362	132,460	26,254
Basic net income (loss) per common share	$ (0.11)	$ 0.45	$ (1.01)	$ 0.41

Diluted								
Net income (loss) available to common stockholders	$	(20,181)	$	11,776	$	(134,289)	$	10,801
Weighted average basic number of common shares outstanding		191,846		26,362		132,460		26,254
Common stock equivalent shares representing shares issued upon exercise or conversion	Anti-dilutive				Anti-dilutive			
Weighted average diluted number of common shares outstanding		191,846		26,362		132,460		26,254
Diluted income (loss) per common share	$	(0.11)	$	0.45	$	(1.01)	$	0.41

Common stock equivalents of stock options, Preferred Stock, February 2012 Warrants, August 2012 Warrants and the 8% Note totaling 78.8 million and 77.1 million shares were not included in the computations of diluted earnings per share of common stock for the three and nine months ended September 30, 2012, respectively, as the effect would have been anti-dilutive due to the net loss.

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14. ADDITIONAL FINANCIAL STATEMENT INFORMATION

Certain balance sheet and statement of operations amounts are comprised of the following (in thousands):

	September 30, 2012	December 31, 2011
Accounts receivable:		
Oil, natural gas and natural gas liquids revenues	$ 60,969	$ 9,519
Joint interest accounts	43,662	597
Affiliated partnerships	204	
Other	453	172
	$ 105,288	$ 10,288
Prepaids and other:		
Prepaid expenses	$ 3,538	$ 936
Other	523	1,793
	$ 4,061	$ 2,729
Accounts payable and accrued liabilities:		
Trade payables	$ 107,482	$ 12,890
Revenues and royalties payable	48,034	8,564
Accrued interest expense	15,849	464
Accrued income taxes payable		406
Accrued employee compensation	11,661	1,600
Drilling advances from partners	15,077	26
Accounts payable to affiliated partnerships	849	
Other	3,392	1,111
	$ 202,344	$ 25,061

	Three months ended September 30, 2012	Three months ended September 30, 2011	Nine months ended September 30, 2012	Nine months ended September 30, 2011
General and administrative:				
General and administrative, overhead and other	$ 31,790	$ 3,100	$ 60,579	$ 10,913
Share-based compensation	1,402	872	6,034	2,227
	$ 33,192	$ 3,972	$ 66,613	$ 13,140
Depletion, depreciation and accretion:				
Depletion and amortization	$ 21,596	$ 4,941	$ 32,141	$ 14,910
Depreciation	535	244	1,096	744
Accretion	595	409	1,424	1,223
	$ 22,726	$ 5,594	$ 34,661	$ 16,877
Interest expense and other, net:				
Interest expense	$ 4,793	$ 3,637	$ 22,023	$ 13,750
Other expense (income)	281	(182)	227	568
	$ 5,074	$ 3,455	$ 22,250	$ 14,318

15. EQUITY INVESTMENTS

As a part of the acquisition of GeoResources discussed in Note 4 Acquisitions , the Company acquired investments, in the form of general partnership interests, in two affiliated partnerships, SBE Partners LP (SBE Partners) and OKLA Energy Partners LP (OKLA Energy). The Company accounts for these investments using the equity method of accounting. Under this accounting method the Company records its net share of income and expenses in Interest expense and other, net line item of its condensed consolidated statements of operations. Contributions to the investment increase the Company s investment while distributions from the investment decrease the Company s carrying value of the investment. These partnerships hold direct working interest in oil and gas properties.

The Company s carrying value for its equity investment in OKLA Energy at September 30, 2012 was $0.7 million. The Company s carrying value for its equity investment in SBE Partners at September 30, 2012 was $10.5 million.

16. SUBSEQUENT EVENTS

Agreement to Acquire Williston Basin Assets

On October 19, 2012, Halcón Energy Properties, Inc., a wholly owned subsidiary of Halcón, entered into Reorganization and Interest Purchase Agreement (the Williston Purchase Agreement) with Petro-Hunt, L.L.C. and Pillar Energy, LLC (collectively, the Petro-Hunt Parties), pursuant to which Halcón has agreed to acquire two newly formed wholly owned subsidiaries of the Petro-Hunt Parties, which immediately before closing will own a total of approximately 81,000 net acres prospective for the Bakken and Three Forks formations primarily located in Williams, Mountrail, McKenzie and Dunn Counties, North Dakota (the Williston Basin Assets). Halcón has agreed to acquire the Williston Basin Assets for a total purchase price of $1.45 billion, consisting of $700 million in cash and $750 million in newly issued Halcón preferred stock that will automatically convert into approximately 100.7 million shares of Halcón common stock at a conversion price of $7.45 per share following stockholder approval of such conversion and an increase in Halcón s authorized common stock. The shares of preferred stock are to be issued to the Petro-Hunt Parties in a private placement pursuant to the exemptions from registration in Regulation D, Rule 506, under Section 4(2) of the Securities Act of 1933, as amended (the Securities Act).

Immediately following the completion of the Williston Basin Assets acquisition (and the related private placement of Halcón common stock described below), the Petro-Hunt Parties are expected to hold preferred stock representing approximately 22% of Halcón s outstanding common stock on an as-converted, fully diluted basis. As holders of the preferred stock, the Petro-Hunt Parties will be entitled to vote on all matters submitted to a vote of Halcón s common stockholders, except for matters required for the conversion of the preferred stock. The voting power attributable to the preferred stock will be limited to 19.99% of the voting power of Halcón s common stock outstanding immediately prior to the issuance of the preferred stock. The preferred stock will accrue dividends at the rate of 8% per annum from the issue date to the extent not converted into common stock within 121 days following issuance. No dividends will be payable if the preferred stock is converted within that period. The conversion rate of the preferred stock will be subject to anti-dilution adjustments in the event of stock splits, stock dividends and under certain other circumstances. In addition, Halcón has agreed to cause one individual designated by the Petro-Hunt Parties to be elected or appointed to Halcón s board of directors, subject to the reasonable approval of Halcón s Nominating and Corporate Governance Committee, for so long as the Petro-Hunt Parties beneficially own at least 5% of the outstanding shares of Halcón common stock.

The effective date of the transaction is June 1, 2012 and Halcón expects to close the transaction in mid-December 2012. The purchase price is subject to 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. Any adjustments to the purchase price at closing would be applied to the cash and convertible preferred stock components of the purchase price in the same proportions.

The transaction is subject to customary closing conditions, including the expiration or early termination of the waiting period mandated under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as well as the execution and delivery of certain other agreements, including a registration rights agreement, a lock-up agreement and a transition services agreement. The lock-up agreement will prohibit the Petro-Hunt Parties from offering for sale, selling, pledging or otherwise disposing of the shares of Halcón convertible preferred stock (or the underlying shares of Halcón common stock) received as consideration for the transaction for a period of 180 days following the closing of the transaction. Halcón has agreed to file with the Securities and Exchange Commission a shelf registration statement relating to the resale of such shares of Halcón capital stock.

The parties may terminate the Williston Purchase Agreement if any of the above closing conditions have not been satisfied, or if total adjustments to the purchase price exceed $217.5 million or the transaction has not closed on or before December 20, 2012.

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Common Stock Purchase Agreement

On October 19, 2012, Halcón entered into a Common Stock Purchase Agreement (the Stock Purchase Agreement) with CPP Investment Board PMI-2 Inc. (CPPIB), pursuant to which CPPIB has agreed to purchase 41,899,441 newly issued shares of Halcón common stock at $7.16 per share for a total purchase price of approximately $300.0 million. The net proceeds to Halcón are expected to be approximately $294.0 million following the payment of an approximate $6.0 million capital commitment payment to CPPIB upon closing of the transaction. The shares of Halcón common stock will be issued to CPPIB in a private placement pursuant to the exemptions from registration provided in Regulation D, Rule 506, under Section 4(2) of the Securities Act. As a result of this transaction, CPPIB is expected to hold approximately 9% of Halcón s outstanding common stock on a fully diluted basis after giving effect to the completion of the Williston Basin Assets acquisition. CPPIB has agreed to a one-year lock-up period, ending October 19, 2013, during which time it will not offer for sale, sell, pledge or otherwise dispose of the shares of Halcón common stock it acquires pursuant to the Stock Purchase Agreement, subject to certain exceptions.

The Stock Purchase Agreement contains customary representations and warranties by Halcón and CPPIB and the parties have agreed to indemnify each other for losses resulting from the other party s breach of any representations, warranties or covenants. Closing of the transaction is subject to customary closing conditions, as well as the closing of Halcón s acquisition of the Williston Basin Assets described above and the execution and delivery of certain other documents, including a stockholders agreement. The stockholders agreement will provide that, for as long as CPPIB beneficially owns at least 5% of Halcón s common stock, it may designate one individual to serve on Halcón s board of directors and two individuals for so long as it owns 20% or more of Halcón s common stock, such individual(s) to be subject to the reasonable approval of Halcón s Nominating and Corporate Governance Committee. The stockholders agreement will also provide CPPIB with certain pre-emptive rights to acquire additional Halcón securities, as well as shelf registration, demand underwriting and piggyback registration rights.

Bridge Facility Commitment and Pending Increase to Credit Facility Borrowing Base

On October 19, 2012, Wells Fargo Securities, LLC, J.P. Morgan Securities LLC, Barclays Capital Inc. and Goldman, Sachs & Co., and certain affiliates thereof, executed a commitment letter pursuant to which, subject to customary terms and conditions, in connection with Halcón s acquisition of the Williston Basin Assets, such parties have committed to backstop an increase in the borrowing base from $525.0 million to $850.0 million under Halcón s revolving credit facility and to provide Halcón with senior unsecured bridge financing of up to $500.0 million.

Offering of 8.875% Senior Notes

On November 6, 2012, Halcón sold, in a private offering to eligible purchasers, $750 million aggregate principal amount of its 8.875% Senior Notes due 2021 (the 8.875% Notes). Net proceeds of $725.6 million from the offering were placed into escrow pending the Company s acquisition of the Williston Basin Assets and will be released upon closing and used to fund the cash portion of the consideration to be paid in the acquisition and for general corporate purposes.

In connection with the 8.875% Notes, the Company anticipates recording a $5.6 million discount to be amortized over the life of the 8.875% Notes using the effective interest method.

The 8.875% Notes have not been registered under the Securities Act or applicable state securities laws and may not be offered or sold in the United States absent registration or an applicable exemption from the registration requirements of the Securities Act and applicable state laws. The 8.875% Notes may be resold by the initial purchasers pursuant to Rule 144A and Regulation S under the Securities Act.

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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, 2012 and 2011 and 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 included in our Annual Report on Form 10-K for the year ended December 31, 2011.

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.

Overview

We are an independent energy company engaged in the acquisition, production, exploration and development of onshore oil and natural gas properties in the United States. Historically, our producing properties are located in basins with long histories of oil and natural gas operations. During the current year we have focused on the acquisition of unevaluated leasehold and producing properties to increase our production levels and provide growth potential through exploration and development in prospect areas. As a consequence of these activities, we have extensive drilling opportunities in multiple basins that we believe allow for repeatable successes and production growth. We believe our portfolio of properties and drilling opportunities provides us with broad flexibility to direct our capital resources to projects with the greatest potential returns.

Our oil and natural gas assets consist of a combination of growth and mature liquids-weighted reserves and undeveloped properties. We have mature oil and natural gas reserves located primarily in Texas, North Dakota, Louisiana, Oklahoma, Montana, and Colorado. We have acquired acreage and may acquire additional acreage in the Utica/Point Pleasant formations in Ohio and Pennsylvania, the Woodbine/Eagle Ford formations in Texas, the Bakken/Three Forks formations in North Dakota and Montana, the Tuscaloosa Marine shale formation in Louisiana, the Midway/Navarro formations in Southeast Texas, the Wilcox formation in Texas and Louisiana and the Mississippi Lime formation in Oklahoma, as well as several other undisclosed locations.

Our average daily oil and natural gas production increased 55% in the first nine months of 2012 compared to the same period in the prior year. During the first nine months of 2012, we averaged 6,401 barrels of oil equivalent (Boe) per day compared to average daily production of 4,132 Boe per day during the first nine months of 2011. The increase in production compared to the prior year period was driven primarily by the acquisitions of GeoResources, Inc. (GeoResources) and the East Texas assets (the East Texas Assets), partially offset by a slight production decline. The acquisitions of GeoResources and the East Texas Assets combined to contribute approximately 2,460 Boe per day of the increase. During the first nine months of 2012, we participated in the drilling of 82 gross (54.5 net) wells of which 40 gross (35 net) wells were completed and capable of production, 40 gross (17.6 net) wells were drilling or waiting on completion and two gross (1.9 net) wells were dry holes. We also drilled and completed four gross (4 net) salt water disposal wells and completed one gross (1 net) well that we did not drill.

Recent Acquisitions

Merger with GeoResources, Inc.

On August 1, 2012, we acquired GeoResources, Inc., by merger, which we refer to as the GeoResources Merger. As consideration, we paid a combination of $20.00 in cash and issued 1.932 shares of the Company s common stock for each share of GeoResources common stock that was issued and outstanding on the closing date and also assumed GeoResources outstanding warrants. GeoResources oil and natural gas properties include acreage in the Bakken and Three Forks formations in North Dakota and Montana, and the Austin Chalk trend and Eagle Ford shale in Texas. As of January 1, 2012, GeoResources reported estimated proved reserves of approximately 29.2 million barrels of oil equivalent (MMBoe), of which approximately 67% was oil and 70% was developed. GeoResources production for the year ended December 31, 2011 was 1.9 MMBoe and for the six months ended June 30, 2012 was 1.4 MMBoe. Prior to the merger, we and GeoResources operated as separate companies. Accordingly, the comparison to prior period results of operations and financial condition set forth below relate solely to us. GeoResources results of operations are reflected in the Company s results from and after August 1, 2012. Net daily production from the GeoResources properties was approximately 8,344 Boe per day during August and September of 2012. Information on the merger is set forth under Note 4 to the condensed consolidated financial statements.

East Texas Assets Acquisition

In early August 2012, we acquired an operated interest in 20,628 net acres of oil and gas leaseholds in East Texas from several private oil and gas companies for cash of approximately $301.6 million and 20.8 million shares of the Company s common stock subject to normal closing adjustments. The properties consist of producing and nonproducing acreage believed to be prospective for the Woodbine, Eagle Ford and other formations. The East Texas Assets results of operations are reflected in the Company s results from and after August 1, 2012. Net daily production from the acreage was approximately 2,700 Boe per day during August and

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September of 2012. Information on the East Texas Asset acquisition is set forth under Note 4 to the condensed consolidated financial statements.

Acquisition of Unevaluated Acreage

On June 28, 2012, we acquired a working interest in approximately 27,000 net acres in Eastern Ohio that we believe is prospective for the Utica shale/Point Pleasant formations. The purchase price in the transaction was approximately $164.0 million. We funded the acquisition with cash on hand. No oil or natural gas production or proved reserves were attributable to the acquired assets.

In addition to the forgoing acquisitions, during the first nine months of 2012 we incurred approximately $403.2 million in capital expenditures on unevaluated oil and gas leaseholds through numerous leasing and acquisition transactions. No oil or natural gas production or proved reserves were attributable to the acquired unevaluated leasehold assets which were primarily located in Texas, Louisiana, Ohio, and Pennsylvania.

Our financial results depend upon many factors, but are largely driven by the volume of our oil and natural gas production and the price that we receive for that production. Our production volumes will decline as reserves are depleted unless we expend capital in successful development and exploration activities or acquire properties with existing production. The amount we realize for our production depends predominately upon commodity prices and our related commodity price hedging activities, which are affected by changes in market demand and supply, as impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. Accordingly, finding and developing oil and natural gas reserves in an economical manner is critical to our long-term success.

Other Recent Developments

Pending Acquisition of Williston Basin Assets

On October 19, 2012, Halcón Energy Properties, Inc., a wholly owned subsidiary of Halcón, entered into a Reorganization and Interest Purchase Agreement (the Williston Purchase Agreement) with Petro-Hunt, L.L.C. and Pillar Energy, LLC (collectively, the Petro-Hunt Parties), pursuant to which we have agreed to acquire two newly formed wholly owned subsidiaries of the Petro-Hunt Parties, which immediately before closing will own a total of approximately 81,000 net acres prospective for Bakken and Three Forks formations primarily located in Williams, Mountrail, McKenzie and Dunn Counties, North Dakota (the Williston Basin Assets). The effective date of the transaction is June 1, 2012 and we expect to close the transaction in mid-December 2012. The purchase price is subject to 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. Any adjustments to the purchase price at closing would be applied to the cash and convertible preferred stock components of the purchase price in the same proportions. The parties may terminate the Williston Purchase Agreement if any of the above closing conditions have not been satisfied, or if total adjustments to the purchase price exceed $217.5 million or the transaction has not closed on or before December 20, 2012.

The total purchase price of $1.45 billion consists of $700 million in cash and $750 million in newly issued Halcón preferred stock that will automatically convert into approximately 100.7 million shares of Halcón common stock at a conversion price of $7.45 per share following stockholder approval of such conversion and an increase in our authorized common stock. The shares of preferred stock are to be issued to the Petro-Hunt Parties in a private placement pursuant to the exemptions from registration in Regulation D, Rule 506, under Section 4(2) of the Securities Act of 1933, as amended (the Securities Act).

The preferred stock will accrue dividends at the rate of 8% per annum from the issue date to the extent not converted into common stock within 121 days following issuance. No dividends will be payable if the preferred stock is converted within that period. The conversion rate of the preferred stock will be subject to anti-dilution adjustments in the event of stock splits, stock dividends and under certain other circumstances. See Note 16 Subsequent Events to the condensed consolidated financial statements for additional discussion on the acquisition of the Williston Basin Assets.

Common Stock Purchase Agreement

On October 19, 2012, we entered into a Common Stock Purchase Agreement (the Stock Purchase Agreement) with CPP Investment Board PMI-2 Inc. (CPPIB), pursuant to which CPPIB has agreed to purchase 41,899,441 newly issued shares of our common stock at $7.16 per share for a total purchase price of approximately $300.0 million. The net proceeds to Halcón are expected to be approximately $294.0 million following the payment of an approximate $6.0 million capital commitment payment to CPPIB upon closing of the transaction. The shares of Halcón common stock will be issued to CPPIB in a private placement pursuant to the exemptions from registration provided in Regulation D, Rule 506, under Section 4(2) of the Securities Act. As a result of this transaction, CPPIB is expected to hold approximately 9% of Halcón s outstanding common stock on a fully diluted basis after giving effect to the completion of the Williston Basin Assets acquisition. CPPIB has agreed to a one-year lock-up period, ending October 19, 2013, during which time it will not offer for sale, sell, pledge or otherwise dispose of the shares of Halcón common stock it acquires pursuant to the Stock Purchase Agreement, subject to certain exceptions.

Offering of 8.875% Senior Notes

On November 6, 2012, we sold, in a private offering to eligible purchasers, $750 million aggregate principal amount of its 8.875% Senior Notes due 2021 (the 8.875% Notes). Net proceeds of $725.6 million from the offering were placed into escrow pending the acquisition of the Williston Basin Assets and will be released upon closing and used to fund the cash portion of the consideration to be paid in the acquisition.

Recapitalization

On February 8, 2012, HALRES LLC (formerly, Halcón Resources, LLC), a newly-formed limited liability company led by Floyd C. Wilson, former Chairman and Chief Executive Officer of Petrohawk Energy Corporation, recapitalized us with a $550.0 million investment structured as the purchase of $275.0 million in new common stock, a $275.0 million five-year 8% convertible note (the 8% Note) and warrants for the purchase of an additional 36,666,666 shares of our common stock at an exercise price of $4.50 per share. Information as to our recapitalization is set forth under Note 2 to the condensed consolidated financial statements.

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February 2012 Credit Facility Amendment

We requested, and were granted, a redetermination of the aggregate amount and borrowing base of the February 2012 Credit Agreement in anticipation of, and contingent upon, the successful completion of the GeoResources and East Texas Assets acquisitions. On August 1, 2012, in connection with the closing of the GeoResources and East Texas Assets acquisition, we entered into the First Amendment to the February 2012 Credit Agreement (the First Amendment). The First Amendment increased the commitments under the revolving credit facility to an aggregate amount up to $1.5 billion and the borrowing base from $225.0 million to $525.0 million. The First Amendment also modified the requirements for commodity hedging to not more than 85% of our projected proved production forecast for 66 months from the date such hedge agreement is created.

February 2012 Credit Facility

In connection with the closing of the recapitalization, we entered into a senior secured revolving credit agreement (the February 2012 Credit Agreement) with JPMorgan Chase Bank, N.A. (JPMorgan), as administrative agent, and other lenders on February 8, 2012. Initially, the February 2012 Credit Agreement provided for a $500.0 million facility with an initial borrowing base of $225.0 million. Amounts borrowed under the February 2012 Credit Agreement will mature on February 8, 2017. The borrowing base will be redetermined semi-annually, with the lenders and us each having the right to one interim unscheduled redetermination between any two consecutive semi-annual redeterminations. The borrowing base takes into account our oil and natural gas properties, proved reserves, total indebtedness, and other relevant factors consistent with customary oil and 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 we may issue. Funds advanced under the February 2012 Credit Agreement may be paid down and re-borrowed during the five-year term of the revolver. The pricing on the February 2012 Credit Agreement is LIBOR plus a margin ranging from 1.5% to 2.5% based on a percentage of usage. Advances under the February 2012 Credit Agreement are secured by liens on substantially all of our properties and assets. The February 2012 Credit Agreement contains representations, warranties and covenants customary in transactions of this nature including restrictions on the payment of dividends on our capital stock and financial covenants relating to current ratio and minimum interest coverage ratio. Initially, prior to the amendment during August 2012, we were required to maintain commodity hedges on a monthly basis of not more than 100% of our projected production for the first 24 months, 75% of our projected production for the next 25 to 36 months and 50% of our projected production for the next 37 to 48 months. At September 30, 2012, we had $185.0 million of indebtedness outstanding, $1.3 million of letters of credit outstanding and $338.7 million of borrowing capacity available under the revolving credit agreement. At September 30, 2012 and as of the date of this filing, we are in compliance with the financial debt covenants under the February 2012 Credit Agreement.

Preferred Stock Offering

On March 5, 2012, we sold in a private placement to certain institutional accredited investors 4,444.4511 shares of 8% automatically convertible preferred stock (Preferred Stock), par value $0.0001 per share, each share of which automatically converted into 10,000 shares of our common stock on April 17, 2012. We received gross proceeds of approximately $400.0 million, or $9.00 per share of common stock, before offering expenses. No cash dividends were paid on the convertible Preferred Stock as it converted into common stock before May 31, 2012. The Preferred Stock was considered to have a beneficial conversion feature because the proceeds per share, approximately $9.00 per share of common stock, were less than the fair value of our common stock of $10.99 per common share on the commitment date. The estimated fair value allocated to the beneficial conversion feature was $88.4 million and was recorded to additional paid-in capital, creating a discount on the Preferred Stock (the Discount). The Discount resulting from the allocation of value to the beneficial conversion feature was required to be amortized over the 71 month contractual period from issuance to required redemption, or fully amortized upon an accelerated date of redemption or conversion, by increasing Preferred Stock and recording the offsetting amount as a deemed non-cash Preferred Stock dividend. During the three months ended March 31, 2012, we recorded a non-cash preferred dividend of $1.1 million. Due to the conversion date occurring on

April 17, 2012, the remaining $87.3 million of Discount amortization was accelerated to the conversion date and reflected as a non-cash preferred dividend during April of 2012.

9.75 % Senior Notes

On July 16, 2012, we completed a private offering of $750.0 million aggregate principal amount of 9.75% senior unsecured notes due 2020 (the 9.75% Notes), issued at 98.646% of par. The net proceeds from the offering approximated $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 GeoResources Merger and East Texas Assets acquisition.

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Capital Resources and Liquidity

The proceeds provided by our recent financing activities have enabled us to increase our focus on expanding our leasehold position in liquids-rich resource areas. We have acquired and/or identified several target resource style plays for additional leasing, including the Bakken/Three Forks formations in North Dakota, Utica/Point Pleasant formations in Ohio and Pennsylvania, the Mississippi Lime formation in Northern Oklahoma and Southern Kansas, the Wilcox formation in Southwest Louisiana, the Midway/Navarro formations in Southeast Texas, the Woodbine/Eagle Ford formations in East Texas, and the Tuscaloosa Marine shale formation in Louisiana. In addition to our ongoing lease acquisition efforts in our targeted resource plays, we have identified several new exploratory areas we believe are prospective for oil and liquids-rich hydrocarbons. We have made significant progress in all of our target resources style plays. For the nine months ended September 30, 2012, excluding our GeoResources and East Texas Asset acquisitions, we invested $634.6 million in unevaluated properties for oil and natural gas leaseholds, exploration activities and seismic. The majority of these expenditures were for acreage in the Utica shale/Point Pleasant and Woodbine/Eagle Ford formations. For the nine months ended September 30, 2012, we invested $93.1 million in the development of our oil and gas properties. Additionally, for the nine months ended September 30 2012, we invested $579.5 million and $296.1 million respectively, in the GeoResources and East Texas Assets acquisitions.

Our near-term capital spending requirements are expected to be partially funded with cash flows from operations, proceeds from potential asset dispositions and borrowings under our February 2012 Credit Agreement, for which the borrowing base has been increased from $225.0 million to $525.0 million due to the completed GeoResources Merger and East Texas Assets acquisition. As of November 5, approximately $415.3 million was drawn on the borrowing base. In addition, and in conjunction with the anticipated December 2012 closing of the Williston Basin Asset transaction the Company will have net proceeds from the $750 million 8.875% Notes and common stock offering to CPPIB of approximately $320 million after satisfying the $700.0 million cash consideration portion of the Williston Basin Assets acquisition and related costs. Furthermore, the closing of the Williston Basin Assets acquisition will result in an increase in our current borrowing base from $525.0 million to $850 million on our February 2012 Credit Facility.

We strive to maintain financial flexibility while continuing our aggressive 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 February 2012 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. 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.

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 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.

Cash Flow

Our primary source of cash for the nine months ended September 30, 2012 was from financing activities. Our primary source of cash for the nine months ended September 30, 2011 was from operating activities. Proceeds from our convertible Preferred Stock and common stock issuance pursuant to our recapitalization, as well as borrowings under our February 2012 Credit Facility, 8% Note and 9.75% notes, were offset by repayments of our previous credit facilities and cash used in investing activities to fund our unevaluated leasehold activities, our drilling program, and our recent acquisitions. Operating cash flow fluctuations were substantially driven by the increase in general and administrative expenses in the nine months ended September 30, 2012 as a result of the February 2012 recapitalization and change in control matters, as well as transaction costs for business acquisitions and mergers.

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

	Nine Months Ended September 30,			
		2012		2011
Cash flows provided by operating activities	$	13,568	$	23,813
Cash flows used in investing activities		(1,624,006)		(19,630)
Cash flows provided by (used in) financing activities		1,628,515		(4,176)
Net increase in cash	$	18,077	$	7

Operating Activities. Net cash provided by operating activities for the nine months ended September 30, 2012 was $13.6 million as compared to cash provided by operating activities for the nine months ended September 30, 2011 of $23.8 million.

Net loss for the nine months ended September 30, 2012 was $45.8 million. Non-cash items, including $34.7 million of depreciation, depletion and accretion, $8.6 million of non-cash interest and amortization and $6.2 million of amortization and write-off of deferred loan costs served to offset this net loss. The recapitalization, including change in control and related activities which occurred during February 2012, merger and acquisition transaction costs and the impact of additional personnel and facilities in support of the rapidly expanding business base, drove a significant increase in general and administrative, which adversely affected operating cash flows.

Investing Activities. The primary drivers of cash used in investing activities is capital spending, specifically the acquisition of unevaluated leaseholds in our targeted areas, the merger with GeoResources, Inc., and the acquisition of the East Texas Assets. Cash used in investing activities was $1.6 billion and $19.6 million for the nine months ended September 30, 2012 and 2011, respectively.

During the first nine months of 2012, we incurred cash expenditures of $579.5 million, net of cash acquired, on the merger with GeoResources, $296.1 million on the acquisition of the East Texas Assets, $93.1 million on evaluated oil and natural gas capital expenditures, and $634.6 million on the unevaluated leasehold acquisitions seismic and exploratory drilling. We participated in the drilling of 82 gross (54.5 net) wells of which 40 gross (35 net) wells were completed and capable of production, 40 gross (17.6 net) wells were drilling or waiting on completion and two gross (1.9 net) wells were dry holes. We also drilled and completed four gross (4 net) salt water disposal wells and completed one gross (1 net) well that we did not drill during the first nine months of 2012. We spent an additional $18.2 million on other operating property and equipment capital expenditures; $12.1 million of the $18.2 million was spent on pipelines and related infrastructure projects and the remainder was spent on leasehold improvements, computers and software primarily in our corporate office in Houston, Texas. Proceeds from sales of oil and gas properties were $0.6 million.

During the first nine months of 2011, we spent $19.6 million on oil and natural gas capital expenditures. During the nine months ended September 30, 2011, we participated in the drilling of 46 gross (40 net) wells, of which 35 gross (31.5 net) wells were capable of production and 11 gross (8.5 net) wells were drilling, testing or waiting on completion as of September 30, 2011. We spent an additional $0.5 million on other operating property and equipment capital expenditures. Proceeds from sales of oil and gas properties were $0.5 million for the nine months ended September 30, 2011.

Financing Activities. Net cash flows provided by financing activities were $1.6 billion as compared to $4.2 million used in financing activities for the nine months ended September 30, 2012 and 2011, respectively.

On February 8, 2012, HALRES LLC recapitalized us with a $550.0 million investment structured as the purchase of $275.0 million in new common stock, a $275.0 million five-year 8% convertible note and warrants for the purchase of an additional 36,666,666 shares of our common stock at an exercise price of $4.50 per share. The convertible note provided $231.4 million cash flow from borrowings and $43.6 million cash flow from warrants issued. In connection with the closing of the recapitalization, we entered into the February 2012 Credit Agreement and terminated our March 2011 credit facilities with the payoff of the $208.0 million balance. We borrowed $305.0 million and repaid $120.0 million under the February 2012 Credit Facility during the first nine months of 2012. See Note 6 Long-Term Debt to the condensed consolidated financial statements for discussion of the Credit Facility.

On March 5, 2012, we received $400.0 million, subject to certain adjustments, from the private placement sale of convertible Preferred Stock.

In connection with the closing of the recapitalization transactions and the Preferred Stock private placement, we incurred a total of $18.1 million in equity issuance costs during the nine months ended September 30, 2012.

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All restricted stock awards were vested as a result of the change in control in February 2012. For the nine months ended September 30, 2012 and 2011, we repurchased $2.1 million and $0.1 million, respectively, in common stock from participants under our 2006 Long-Term Incentive Plan to net settle the related withholding tax liability.

On June 29, 2012, we priced $750.0 million aggregate principal amount of 9.75% senior unsecured notes due 2020 in a private offering. Net proceeds from these notes of approximately $723.1 million were funded into escrow on July 16, 2012 and subsequently released from escrow on August 1, 2012 and utilized to fund portions of the GeoResources and East Texas Assets transactions. See Other Recent Developments 9.75% Senior Notes in Item 2 for a more detailed discussion.

We incurred debt issuance costs of $2.5 million, $4.4 million, and $16.8 million associated with the issuance of the 8% Note, February 2012 credit facility and 9.75% Notes, respectively.

Contractual Obligations

We have non-cancelable purchase commitments for pipe, storage tanks, and production equipment of $5.9 million at September 30, 2012. We are also obligated under contracts for drilling rigs and related equipment of $57.9 million at September 30, 2012. Early termination of the drilling rigs and related equipment contracts would require termination penalties of $38.5 million, which would be in lieu of paying the remaining drilling commitments of $57.9 million. Our level of capital expenditures will vary in future periods depending on the success we experience in our acquisition, development and exploration activities, oil and natural gas price conditions and other related economic factors. At September 30, 2012, we have non-cancelable operating leases of $41.5 million, primarily related to our corporate office lease in Houston, Texas, which expire on various dates through 2020. Currently, no sources of liquidity or financing are provided by off-balance sheet arrangements or transactions with unconsolidated, limited-purpose entities.

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 year ended December 31, 2011.

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Results of Operations

Three Months Ended September 30, 2012 and 2011

We reported a net loss of $20.2 million for the three months ended September 30, 2012 and net income of $11.8 million for the three months ended September 30, 2011, resulting in a decline in net income of $32.0 million. The following tables summarize key items of comparison and their related change for the periods indicated (in thousands, except per unit and Boe amounts).

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Change
Net income (loss)	$ (20,181)	$ 11,776	$ (31,957)
Operating revenues:			
Oil	65,662	18,955	46,707
Natural gas	3,775	2,548	1,227
Natural gas liquids	3,214	2,644	570
Other revenue	489	39	450
Operating expenses:			
Production:			
Lease operating	15,511	7,363	8,148
Workovers	1,123	136	987
Taxes	4,432	1,391	3,041
General and administrative:			
General and administrative	31,790	3,100	28,690
Share-based compensation	1,402	872	530
Restructuring	725		725
Depletion, depreciation and accretion:			
Depletion - full cost	21,596	4,941	16,655
Depreciation - other	535	244	291
Accretion	595	409	186
Other income (expenses):			
Interest expense	(4,793)	(3,637)	(1,156)
Other income (expense)	(281)	182	(463)
Net gain (loss) on derivative contracts	(9,575)	22,617	(32,192)
Income (loss) before income taxes	(19,218)	24,892	(44,110)
Income tax provision	963	13,116	(12,153)

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	Three Months Ended September 30, 2012	2011	Change
Production:			
Oil (MBbls)	704	213	491
Natural gas (MMcf)	1,441	615	826
Natural gas liquids (MBbls)	85	45	40
Total MBoe	1,029	361	668
Average daily production (Boe)	11,185	3,924	7,261
Average price per unit:			
Oil (Bbl)	$ 93.27	$ 88.99	$ 4.28
Natural gas (Mcf)	2.62	4.14	(1.52)
Natural gas liquids (Bbl)	37.81	58.76	(20.95)
Total per Boe	70.60	66.89	3.71
Average cost per Boe:			
Production:			
Lease operating	$ 15.07	$ 20.40	$ (5.33)
Workovers	1.09	0.38	0.71
Taxes	4.31	3.85	0.46
General and administrative:			
General and administrative	30.90	8.59	22.31
Share-based compensation	1.36	2.41	(1.05)
Restructuring costs	0.70		0.70
Depletion	20.99	13.69	7.30

For the three months ended September 30, 2012, oil, natural gas and natural gas liquids revenues increased $48.5 million from the same period in 2011. The increase was primarily due to an increase in production volumes resulting from the GeoResources Merger and the East Texas Assets acquisition which collectively accounted for an increase of 674 Mboe in production and $49.0 million of incremental revenues. While the newly acquired properties increased revenue and production volumes, the full impact was partially offset by a reduction in production of approximately 12 MBoe as a result of shut -in production in Louisiana due to Hurricane Isaac in late August 2012. Realized average prices per Boe increased $3.71 or 6%.

Lease operating expenses increased $8.1 million for the three months ended September 30, 2012, primarily due to $6.1 million of costs incurred on our newly acquired assets. The remaining increases are due to higher power costs, service costs and repairs. Lease operating expenses were $15.07 per Boe in 2012 compared to $20.40 per Boe in 2011. The decrease per Boe is primarily due to a lower rate per Boe on the newly acquired properties.

Workover expenses increased $1.0 million for the three months ended September 30, 2012 compared to the same period in 2011 primarily due to $0.8 million of expenses incurred on our newly acquired assets.

Oil and natural gas production taxes increased $3.0 million for the three months ended September 30, 2012 as compared to the same period in 2011 primarily due to $3.1 million of production taxes incurred on our newly acquired properties. 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 directly. As a percentage of revenue, oil and natural gas production tax was 6.1% for the three months ended September 30, 2012 and 5.8% for the three months ended September 30, 2011.

General and administrative expense for the three months ended September 30, 2012 increased $28.7 million to $31.8 million as compared to the same period in 2011. The increase was primarily due to transaction costs of $17.6 million for business acquisitions and mergers. The remaining increase in general and administrative expenses is attributable to increases in payroll and related employee costs, general office and other costs and professional fees of $8.7 million, $1.8 million and $2.4 million, respectively, in support of the expanding business base and increased corporate activities subsequent to the recapitalization. These increases were partially offset by $2.2 million in capitalized general and administrative expenses.

Share-based compensation expense for the quarter ended September 30, 2012 was $1.4 million, an increase of $0.5 million compared to the same period in 2011. The increase is primarily due to a higher fair value on awards outstanding during the 2012 period resulting in a higher amortization expense. Awards outstanding in the 2011 period were all fully vested in connection with the recapitalization in February 2012 and new awards have been issued during 2012 to the expanding employee base.

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We incurred $0.7 million in restructuring costs for the three months ended September 30, 2012 related to the 2012 restructuring to close the Plano, Texas office and began the process of relocating key administrative functions to our corporate headquarters in Houston, Texas. There were no restructuring costs incurred for the three months ended September 30, 2011.

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 volume for the current period to total remaining reserve volume for the evaluated properties. Depletion expense increased $16.7 million for the three months ended September 30, 2012 compared to the same period in 2011, to $21.6 million primarily due to a higher depletion rate per Boe and increased production. On a per unit basis, depletion expense was $20.99 per Boe for the quarter ended September 30, 2012 compared to $13.69 per Boe for the quarter ended September 30, 2011. The increase in the depletion rate per Boe and production is primarily due to the GeoResources Merger and East Texas Assets acquisition during the third quarter of 2012.

We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil and natural gas production. We have also, in the past, entered into interest rate swaps to mitigate exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. 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, 2012, we had a $3.4 million net derivative receivable, $2.7 million of which was classified as current, and $0.7 million of which was classified as noncurrent. We recorded a net derivative loss of $9.6 million ($11.8 million net unrealized losses and $2.2 million net realized gain on settled contracts and premium costs) for the three months ended September 30, 2012 compared to a net derivative gain of $22.6 million unrealized in the same period in 2011. The change from a gain on derivative contracts for the quarter ended September 30, 2011, to a loss on derivative contracts for the quarter ended September 30, 2012, is primarily due to price changes in the futures curve of forecasted commodity prices (the forward price curve). In 2011, the significant downward shift in the forward price curve for NYMEX crude oil resulted in a net unrealized gain. In 2012, the upward shift in the forward price curve for NYMEX crude oil resulted in a net unrealized loss.

Interest expense increased from $3.6 million for the three months ended September 30, 2011 to $4.8 million for the same period in 2012 due to higher average outstanding borrowings at higher interest rates during the 2012 period. These increases were primarily due to the issuance of the 8% Note during February 2012 and the 9.75% senior notes during August 2012, partially offset by capitalized interest expense on unevaluated properties. Due to significant costs incurred during 2012 on unevaluated properties the Company began capitalizing interest during 2012, resulting in $19.5 million capitalized for the three months ended September 30, 2012.

Based on the estimated effective annual tax rate, we recorded an income tax expense of $1.0 million, including a benefit of $0.4 million related to discrete items, on a pre-tax loss of $19.2 million for the three months ended September 30, 2012, resulting in a negative effective tax rate of 5% as of September 30, 2012. The negative effective tax rate is a result of nondeductible costs for taxable income included in the Company s net loss. The Company incurred nondeductible interest expense on the 8% Note issued as part of the recapitalization of the Company and nondeductible merger costs associated with the acquisition of GeoResources. For the three months ended September 30, 2011, we recorded income tax provision of $13.1 million, including an expense of $2.1 million related to discrete items, on pretax book income of $24.9 million, resulting in an effective tax rate of 53%.

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Nine Months Ended September 30, 2012 and 2011

We reported a net loss of $45.8 million for the nine months ended September 30, 2012 compared to a net income of $10.8 million for the same period in 2011, resulting in a decrease in net income of $56.6 million. The following tables summarize 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, 2012	2011	Change
Net income (loss)	$ (45,844)	$ 10,801	$ (56,645)
Operating revenues:			
Oil	109,042	62,150	46,892
Natural gas	6,683	8,252	(1,569)
Natural gas liquids	7,006	7,582	(576)
Other revenue	560	124	436
Operating expenses:			
Production:			
Lease operating	32,121	23,016	9,105
Workovers	2,384	1,032	1,352
Taxes	7,354	4,280	3,074
General and administrative:			
General and administrative	60,579	10,913	49,666
Share-based compensation	6,034	2,227	3,807
Restructuring	1,732		1,732
Depletion, depreciation and accretion:			
Depletion - full cost	32,141	14,910	17,231
Depreciation - other	1,096	744	352
Accretion	1,424	1,223	201
Other income (expenses):			
Interest expense	(22,023)	(13,750)	(8,273)
Other expense	(227)	(568)	341
Net gain (loss) on derivative contracts	(849)	16,635	(17,484)
Income (loss) before income taxes	(44,673)	22,080	(66,753)
Income tax provision	1,171	11,279	(10,108)

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	Nine Months Ended September 30, 2012	2011	Change
Production:			
Oil (MBbls)	1,151	661	490
Natural gas (MMcf)	2,640	1,985	655
Natural gas liquids (MBbls)	163	136	27
Total MBoe	1,754	1,128	626
Average daily production (Boe)	6,401	4,132	2,269
Average price per unit:			
Oil (Bbl)	$ 94.74	$ 94.02	$ 0.72
Natural gas (Mcf)	2.53	4.16	(1.63)
Natural gas liquids (Bbl)	42.98	55.75	(12.77)
Total per Boe	69.97	69.13	0.84
Average cost per Boe:			
Production:			
Lease operating	$ 18.31	$ 20.40	$ (2.09)
Workovers	1.36	0.91	0.45
Taxes	4.19	3.79	0.40
General and administrative:			
General and administrative	34.54	9.68	24.86
Share-based compensation	3.44	1.97	1.47
Restructuring costs	0.99		0.99
Depletion	18.32	13.22	5.10

For the nine months ended September 30, 2012, oil and natural gas revenues and natural gas liquids increased $44.7 million from the same period in 2011. The increase was primarily due to an increase in production volumes resulting from the GeoResources Merger and the East Texas Assets acquisition which collectively accounted for an increase of 674 Mboe in production and $49.0 million of incremental revenues. While the newly acquired properties increased revenue and production volumes, the full impact was partially offset by a reduction in production of approximately 12 MBoe as a result of shut -in production in Louisiana due to Hurricane Isaac in late August 2012. Realized average prices per Boe increased slightly by $0.84 or 1%.

Lease operating expenses increased $9.1 million for the nine months ended September 30, 2012, primarily due to $6.1 million of expenses incurred on our newly acquired assets during the 2012 period. The remaining increases are due to higher service, repair and employee related costs during the 2012 period. Lease operating expenses were $18.31 per Boe in 2012 compared to $20.40 per Boe in 2011. The decrease per Boe is primarily due to a lower rate per Boe on the newly acquired properties.

Workover expenses increased $1.4 million for the nine months ended September 30, 2012 compared to the same period in 2011 primarily due to $0.8 million of expense on our newly acquired properties and $0.5 million of increased activity on one of our Louisiana properties.

Oil and natural gas production taxes increased $3.1 million for the nine months ended September 30, 2012 as compared to the same period in 2011 primarily due to $3.1 million of production taxes on our newly acquired properties. Most production taxes are based on realized prices at the wellhead, while Louisiana production taxes are based on volumes for natural gas and values for oil. As revenues or volumes from oil and natural gas sales increase or decrease, production taxes on these sales also increase or decrease directly. As a percentage of revenue, oil and natural gas production tax was 6.0% for the nine months ended September 30, 2012 compared to 5.5% for the nine months ended September 30, 2011.

General and administrative expense for the nine months ended September 30, 2012 increased $49.7 million to $60.6 million as compared to the same period in 2011. The majority of the increase is due to recapitalization costs, increased employee related costs, and acquisitions related transaction costs. We incurred $5.4 million for change in control payments in connection with the recapitalization, an increase of $13.3 million in employee related costs in support of the expanding business base and $20.4 million in transaction costs related to the acquisitions of GeoResources and the East Texas Assets in 2012. Other increases include charges of approximately $4.9 million in professional fees resulting from an increase in corporate activities subsequent to the recapitalization and $2.5 million for engagement termination fees.

Share-based compensation expense for the nine months ended September 30, 2012 was $6.0 million, an increase of $3.8 million compared to the same period in 2011. The increase is primarily due to $4.3 million for the accelerated vesting of restricted stock awards and stock appreciation rights resulting from the change in control that occurred due to our recapitalization in February 2012.

We incurred $1.7 million in restructuring costs for the nine months ended September 30, 2012 related to the 2012 restructuring to close the Plano, Texas office and began the process of relocating key administrative functions to our corporate headquarters in Houston, Texas. There were no restructuring costs incurred for the nine months ended September 30, 2011.

Depletion for oil and natural gas properties is calculated using the unit of production method, which depletes the capitalized costs associated with evaluated properties plus future development costs based on the ratio of production volumes for the current period to total remaining reserve volumes for the evaluated properties. Depletion expense increased $17.2 million for the nine months ended September 30, 2012 from the same period in 2011 to $32.1 million. On a per unit basis, depletion expense was $18.32 per Boe for the nine months ended September 30, 2012 compared to $13.22 per Boe for the nine months ended September 30, 2011. The increase in the depletion rate per Boe is primarily due to the GeoResources Merger and the East Texas Assets acquisition during the third quarter of 2012.

We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil and natural gas production. We have also, in the past, entered into interest rate swaps to mitigate exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. 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, 2012, we had a $3.4 million net derivative receivable, $2.7 million of which was classified as current, and $0.7 million of which was classified as noncurrent. We recorded a net derivative loss of $0.9 million ($4.1 million net unrealized losses and $3.2 million net realized gain on settled contracts and premium costs) for the nine months ended September 30, 2012 compared to a net derivative loss of $16.6 million ($18.0 million net unrealized gain and $1.4 million net realized loss on settled contracts and premium costs) in the same period in 2011. The change from a gain on derivative contracts for the nine months ended September 30, 2011, to a loss on derivative contracts for the nine months ended September 30, 2012, is primarily due to the changes in forward curve of forecasted commodity prices (the forward price curve). In 2011, the significant downward shift in the forward price curve for NYMEX crude oil resulted in a net unrealized gain. In 2012, the upward shift in the forward price curve for NYMEX crude oil resulted in a net unrealized loss.

Interest expense increased by $8.3 million for the nine months ended September 30, 2012 compared to the same period in 2011, primarily due to the increased debt outstanding at higher interest rates during 2012 as a result of the issuance of the 8% Note and the 9.75% Notes. Interest expense also includes the expensing of $7.3 million in unamortized debt issuance costs and prepayment fees in connection with the payoff of the March 2011 credit facilities as part of the recapitalization during February 2012. These increases were partially offset by $22.9 million of capitalized interest primarily on unevaluated properties during the 2012 period.

Based on the estimated effective annual tax rate, we recorded a tax provision of $1.2 million, including $0.9 million related to discrete items, on pre-tax loss of $44.7 million for the nine months ended September 30, 2012. We calculated an estimated negative effective annual tax rate of 2.6% for the current annual reporting period as of September 30, 2012. The negative effective tax rate is a result of nondeductible costs for taxable income included in the Company s net loss. The Company incurred nondeductible interest expense on the 8% Note issued as part of the recapitalization of the Company and nondeductible merger costs associated with the acquisition of GeoResources. For the nine months ended September 30, 2011, we recorded income tax provision of $11.3 million, including $2.1 million related to a discrete item, on a pre-tax income of $22.1 million, resulting in an effective tax rate of 51%.

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.

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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 and natural gas prices decline significantly, our ability to finance our capital budget and operations could be adversely impacted. We currently sell most of our oil, natural gas and natural gas liquids production under market price contracts. For the three months ended September 30, 2012, four purchasers accounted for $15.0 million, $10.5 million, $9.2 million and $8.7 million, respectively, or approximately 60% of our revenue from oil, natural gas, and natural gas liquids. For the nine months ended September 30, 2012, two of our purchasers accounted for $34.3 million and $28.0 million, respectively, or approximately 51%, of our revenue from the sales of oil, natural gas and natural gas liquids. No other purchaser accounted for 10% or more of our oil, natural gas and natural gas liquids revenues for the three or the nine months ended September 30, 2012.

We expect energy prices to remain volatile and unpredictable; therefore, we have designed a risk management policy which provides for the use of derivative instruments to provide partial protection against declines in oil and natural gas prices by reducing the risk of price volatility and the effect it could have on our operations. The types of derivative instruments that we typically utilize include collars, three-way collars and puts. The total volumes which we hedge through the use of derivative instruments varies from period to period; however, generally our objective is to hedge 80% of our current and anticipated production for the next 24 months. Our hedging policies and objectives may change significantly as commodities prices or price futures change.

We are exposed to market risk on our open derivative contracts of non-performance by our counterparties. We do not expect such non-performance because our contracts are with major financial institutions with investment grade credit ratings. The counterparties to our derivative contracts are lenders in our credit agreement. We did not post collateral under these contracts as they are secured under our credit agreement. Please refer to Item 1. Financial Statements (Unaudited) Note 11, Derivatives for additional information.

Based on September 30, 2012 NYMEX forward curves of natural gas and crude oil futures prices, adjusted for our counterparties credit risks, we would expect to receive future cash payments of $2.7 million over the next twelve months and $0.7 million over the remaining terms until maturity of our natural gas and crude oil arrangements. If future prices of natural gas and crude oil were to decline by 10%, we would expect to receive future cash payments under our natural gas and crude oil derivative arrangements of $29.4 million, and if future prices were to increase by 10%, we would expect to pay future cash payments of $30.7 million.

We account for our derivative activities under the provisions of Topic 815 of the Codification, *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. Financial Statements (Unaudited) Note 11, Derivatives for additional information.

Interest Rate Sensitivity

We are exposed to market risk related to adverse changes in interest rates. Our interest rate risk exposure results primarily from fluctuations in variable rates, which are LIBOR based and may result in reductions of earnings or cash flows due to increases in the interest rates we pay on our borrowings.

At September 30, 2012, the Company had $185.0 million indebtedness outstanding under our February 2012 Credit Agreement which bears interest at LIBOR plus 150 to 250 basis points. We had $250.0 million in long-term debt net of $39.7 million of unamortized discount related to the 8% Note. We had $740.0 million in long-term debt net of $10.0 million of unamortized discount related to the 9.75% Notes. Fluctuations in market interest rates will cause our annual interest costs on borrowings under our February 2012 Credit Agreement to fluctuate proportionately. Fluctuations in market interest rates will not affect our annual interest costs on our 8% Note or our 9.75% Notes.

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, 2012. 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

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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 effect any change in our internal controls over financial reporting during the quarter ended September 30, 2012 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Reference is made to Part I, Item 3, Legal Proceeding, in our annual report on Form 10-K for the year ended December 31, 2011 and Part II, Item 1, Legal Proceedings, in our quarterly report on Form 10-Q for the quarters ended March 31, 2012 and June 30, 2012, for discussion of pending legal proceedings to which we are a party.

On July 16, 2012, a settlement agreement was entered into, subject to the court s approval, regarding the settlement of the action styles *Yost v. GeoResources, Inc. et al.,* Case No. 1:12-CV-01307-MSK-KMT, pending in the United States District Court for the District of Colorado, which was filed on behalf of a putative class of GeoResources stockholders against GeoResources, the GeoResources board of directors and in certain instances, Halcón and certain subsidiaries of Halcón as aiders and abettors. Pursuant to such settlement, Halcón and GeoResources agreed to make certain supplemental disclosures regarding the merger and to provide additional disclosures to their stockholders, which disclosures were included in a Form 8-K filed with the U.S. Securities and Exchange Commission on July 18, 2012. Objections to the settlement agreement were to be submitted by August 15, 2012 to the federal court in Colorado. A hearing on the settlement agreement is expected to be scheduled at a later date.

Item 1A. Risk Factors

Reference is made to Part I, Item 1A, Risk Factors, in our annual report on Form 10-K for the year ended December 31, 2011 for a discussion of additional risk factors which could materially affect our business, financial condition or future results.

Restrictive covenants in the indenture governing our senior notes and in our revolving credit facility could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

The indentures governing our senior notes due 2020, which we refer to as the 9.75% Notes, and our senior notes due 2021, which we refer to as the 8.875% Notes , impose significant operating and financial restrictions on us. These restrictions limit our ability and that of our restricted subsidiaries to, among other things:

- pay dividends on or make distributions in respect of our capital stock or make other restricted payments;
- incur additional indebtedness;
- create liens;
- engage in mergers or consolidations or sell or otherwise dispose of all or substantially all of our assets;
- make certain dispositions and transfers of assets; and
- engage in transactions with affiliates.

In addition, our revolving credit facility contains a number of significant covenants that, among other things, restrict our ability to:

- dispose of assets;
- incur or guarantee additional indebtedness and issue certain types of preferred stock;
- pay dividends on our capital stock;
- create liens on our assets;
- enter into sale or leaseback transactions;
- enter into specified investments or acquisitions;
- repurchase, redeem or retire our capital stock or subordinated debt;
- merge or consolidate, or transfer all or substantially all of our assets and the assets of our subsidiaries;
- engage in specified transactions with subsidiaries and affiliates; or
- pursue other corporate activities.

We may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants under the indentures governing the 9.75% Notes and the 8.875% Notes and our revolving credit facility. Also, our revolving credit

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facility requires us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Our ability to comply with these ratios and financial condition tests may be affected by events beyond our control and, as a result, we may be unable to meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary corporate activities. A decline in oil, NGL and natural gas prices, or a prolonged period of oil, NGL and natural gas prices at lower levels, could eventually result in our failing to meet one or more of the financial covenants under our credit agreement, which could require us to finance or amend the credit agreement resulting in the payment of consent fees or higher interest rates, or require us to raise additional capital at an inopportune time or on terms not favorable to us.

A breach of any of these covenants or our inability to comply with the required financial ratios or financial condition tests could result in a default under our credit agreement. A default under our credit agreement or the indentures governing the 9.75% Notes and the 8.875% Notes, if not cured or waived, could result in acceleration of all indebtedness outstanding thereunder. The accelerated debt would become immediately due and payable. If that should occur, we may be unable to pay all such debt or to borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms that are acceptable to us. Moreover, any new indebtedness we incur may impose financial restrictions and other covenants on us that may be more restrictive than the revolving credit facility or the indentures governing the 9.75% Notes and the 8.875% Notes.

Our debt level in the future and the covenants in the agreements governing our debt could negatively impact our financial condition, results of operations and business.

Our level of indebtedness in the future, and the covenants contained in the agreements governing our debt, could have important consequences for our operations, including by:

- making it more difficult for us to satisfy our obligations under the 9.75% Notes, the 8.875% Notes or other indebtedness and increasing the risk that we may default on our debt obligations;
- requiring us to dedicate a substantial portion of our cash flow from operations to required payments on indebtedness, thereby reducing the availability of cash flow for working capital, capital expenditures and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate and other activities;
- limiting management s discretion in operating our business;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- detracting from our ability to withstand successfully a downturn in our business or the economy generally;
- placing us at a competitive disadvantage against less leveraged competitors; and
- making us vulnerable to increases in interest rates, because debt under any senior revolving credit facility may vary with prevailing interest rates.

We may be required to repay all or a portion of our debt on an accelerated basis in certain circumstances. If we fail to comply with the covenants and other restrictions in the agreements governing our debt, it could lead to an event of default and the consequent acceleration of our obligation to repay outstanding debt. Our ability to comply with these covenants and other restrictions may be affected by events beyond our control, including prevailing economic and financial conditions.

We are able to incur a substantial amount of additional indebtedness. This could further exacerbate the risks associated with our indebtedness.

Our revolving credit facility currently has a borrowing base of $525.0 million for secured borrowings, subject to periodic borrowing base redeterminations. If new debt is incurred, the related risks that we and our subsidiaries now face could intensify. Increased leverage could, for example:

- make it more difficult for us to satisfy our obligations under our indebtedness; if we fail to comply with the requirements of our indebtedness, that failure could result in an event of default of such indebtedness;
- require us to dedicate a substantial portion of our cash flow from operations to required payments on indebtedness, thereby reducing the availability of cash flow for working capital, capital expenditures and other business activities;
- limit our ability to obtain additional financing in the future for working capital, capital expenditures and other general corporate purposes;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- diminish our ability to successfully withstand a downturn in our business or the economy generally; and
- place us at a competitive disadvantage against less leveraged competitors.

If new debt is added to our and our subsidiaries current debt levels, the related risks that we and they now face could increase.

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Our business plan includes substantial capital requirements which may require additional debt or equity financing.

We expect to make substantial capital expenditures for the acquisition, development, production and exploration of our oil and natural gas properties in order to fully execute our business plan. Our capital requirements will depend on numerous factors, and we cannot predict accurately the exact timing and amount of our capital requirements. Although we intend to finance a substantial portion of our future capital expenditures through cash flow from operations, cash on hand, and our revolving credit facility, we may require additional funds which could come from debt or equity financing or asset sales. A decrease in expected revenues or adverse change in market conditions could make obtaining financing economically unattractive or impossible or reduce the value we expect to receive from asset divestitures.

A significant increase in our indebtedness, or an increase in our indebtedness that is proportionately greater than our issuances of equity could negatively impact our ability to remain in compliance with the financial covenants under our revolving credit facility which could force us to limit or defer our planned natural gas and oil leasing, exploration and development program. Moreover, if we are unable to finance our growth as expected, we could be required to sell assets, seek alternative financing, the terms of which may not be attractive to us, or reduce the scope of our business plan. In addition, a significant increase in our indebtedness could cause us to be unable to obtain sufficient credit capacity with counterparties to finance the hedging of our future crude oil and natural gas production which may limit our ability to manage price risk. As a result of these factors, we may lack the capital necessary to fully pursue our drilling program, obtain credit necessary to enter into derivative contracts to hedge our future crude oil and natural gas production or to capitalize on other business opportunities.

Part of our strategy involves exploratory drilling, including drilling in new or emerging unconventional resource plays using horizontal drilling and completion techniques. The results of our planned exploratory drilling program are subject to more uncertainties than conventional drilling programs in more established formations and may not meet our expectations for reserves or production.

The results of our exploratory drilling in new or emerging plays are more uncertain than drilling results in areas that are developed and have established production. Because new or emerging plays and new formations have limited or no production history, we are less able to use past drilling results in those areas to help predict our future drilling results. Further, part of our drilling strategy to maximize recoveries in certain formations may involve the drilling of horizontal wells using completion techniques that have proven to be successful in other unconventional formations. Our experience with horizontal drilling in these areas to date, as well as the industry s drilling and production history, is limited. The ultimate success of these drilling and completion strategies and techniques will be better evaluated over time as more wells are drilled and production profiles are better established.

Further, access to adequate gathering systems or pipeline takeaway capacity, the availability of drilling rigs, completion and other services and access to midstream services may be more challenging in new or emerging plays. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems and takeaway capacity or otherwise, and/or oil, NGL or natural gas price decline, the return on our investment in these areas may not be as attractive as we anticipate and we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

Our exploration and development drilling efforts and the operation of our wells may not be profitable or achieve our targeted returns.

Exploration, development, drilling and production activities are subject to many risks, including the risk that commercially productive reservoirs will not be discovered. We plan to invest in property, including undeveloped leasehold acreage, which we believe will result in projects that will add value over time. However, we cannot guarantee that all of our prospects will result in viable projects or that we will not abandon our initial investments. Additionally, we cannot guarantee that the leasehold acreage we acquire will be profitably developed, that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such leasehold acreage or wells. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting operating and other costs. In addition, wells that are profitable may not achieve our targeted rate of return.

Our ability to achieve our target results are dependent upon the current and future market prices for oil, NGLs and natural gas, costs associated with producing oil, NGLs and natural gas and our ability to add reserves at an acceptable cost. We significantly rely on 3-D seismic data and other advanced technologies in identifying leasehold acreage prospects and in conducting our exploration activities. The 3-D seismic data and other technologies we use do not allow us to know conclusively prior to our acquisition of leasehold acreage or drilling a well whether oil, NGLs or gas is present or may be produced economically. The use of 3-D seismic data and other technologies also requires greater pre-drilling expenditures than traditional drilling strategies.

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Many of the emerging resource plays that we have targeted have limited or no production history using the drilling and completion methods that we expect to employ. Accordingly, these operations are subject to more uncertainties than our drilling activities in more established fields and formations and may not meet our expectations for reserves or production or our costs to operate may be higher than initially expected. If initially successful, the ultimate success of these drilling and completion strategies and techniques in these new formations will be better evaluated over time as more wells are drilled and production profiles are better established. In addition, we may not be successful in controlling and reducing our drilling and production costs in order to improve our overall return. The cost of drilling, completing and operating a well is often uncertain and cost factors can adversely affect the economics of a project. We cannot predict the cost of drilling and completion, and we may be forced to limit, delay or cancel drilling and completion operations as a result of a variety of factors, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents and shortages or delays in the availability of oilfield services or drilling rigs and other equipment;
- adverse weather conditions, including hurricanes; and
- compliance with and changes in governmental regulations.

Operating hazards and uninsured risks may result in substantial losses.

Our operations are subject to all of the hazards and operating risks inherent in drilling for, and the production of, oil, NGLs and natural gas, including the risk of fire, explosions, blow-outs, pipe failure, abnormally pressured formations and environmental hazards such as oil spills, gas leaks, ruptures or discharges of toxic gases. The occurrence of any of these events could result in substantial losses to us due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation penalties, remedial actions and suspension of operations. For example, we recently received citations from the Occupational Safety and Health Administration (OSHA) following an incident that occurred at one of our Electra/Burkburnett operating locations. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks. There can be no assurance that any insurance will be adequate to cover any losses or liabilities. We cannot predict the continued availability of insurance, or its availability at premium levels that justify its purchase. We do not maintain insurance for regulatory penalties or enforcement actions, such as the OSHA citations. In addition, we may be liable for environmental damage caused by previous owners of properties purchased by us, which liabilities would not be covered by our insurance.

We will be subject to risks in connection with acquisitions, and the integration of significant acquisitions may be difficult.

Our business plan contemplates significant acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions that appear to fit within our overall business strategy, which may include the acquisition of asset packages of producing properties or existing companies or businesses operating in our industry, such as the GeoResources merger and our acquisition of the East Texas Assets. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil, NGL and natural gas prices and their appropriate differentials;
- development and operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We are not entitled to contractual indemnification for environmental liabilities and acquire properties on an as is basis.

Significant acquisitions of existing companies or businesses and other strategic transactions may involve additional risks, including:

- diversion of our management s attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;

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- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with our own while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate organizations;
- the challenge of integrating environmental compliance systems to meet requirements of rapidly changing regulations; and
- the challenge of attracting and retaining personnel associated with acquired operations.

The process of integrating operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to manage the integration process effectively, or if any significant business activities are interrupted as a result of the integration process, our business could be materially and adversely affected.

Regulation and recent court decisions related to greenhouse gas emissions could have an adverse effect on our operations and demand for oil and natural gas.

The U.S. Congress has previously considered legislation to reduce emissions of greenhouse gases, including carbon dioxide, methane and nitrous oxide among others, which some studies have suggested may be contributing to warming of the earth s atmosphere. However, legislation to reduce greenhouse gases appears less likely in the near term. As a result, near term regulation of greenhouse gases, if any, is more likely to come from regulatory action by the Environmental Protection Agency (EPA) or by the several states that have already taken legal measures to reduce emissions of greenhouse gases.

As a result of the U.S. Supreme Court s decision on April 2, 2007 in Massachusetts, et al. v. EPA, 549 U.S. 497 (2007), finding that greenhouse gases fall within the Clean Air Act (CAA) definition of air pollutant, EPA was required to determine whether emissions of greenhouse gases endanger public health or welfare. On December 15, 2009, EPA promulgated its final rule, Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, finding that (i) the current and projected emissions of six key well-mixed greenhouse gases, including carbon dioxide and methane, constitute a threat to public health and welfare, and (ii) the combined emissions from motor vehicles cause and contribute to the climate change problem which threatens public health and welfare. These findings did not themselves impose any requirements on industry or other entities, but were a prerequisite to EPA s adoption of greenhouse gas emission standards for motor vehicles. On May 7, 2010, EPA and the Department of Transportation s National Highway Traffic and Safety Administration, or NHTSA, promulgated a final action establishing a national program providing new standards for certain motor vehicles to reduce greenhouse gas emissions and improve fuel economy, with EPA adopting the standards under the CAA, and NHTSA adopting the standards as Corporate Average Fuel Economy standards under the Energy Policy and Conservation Act. These motor vehicle regulations did not directly impact oil and natural gas production operations, but the result of these actions was significant in that they automatically triggered application of certain CAA permit programs for stationary greenhouse gas emissions sources, potentially including oil and natural gas production operations. These programs, the Prevention of Significant Deterioration (PSD) and Title V Operating Permit programs, have historically applied to sources of air pollutants subject to regulation with emissions exceeding either 100 or 250 tons per year, depending on the nature of the source. To avoid the broad impact of such low permitting thresholds for greenhouse gas emission sources, on June 3, 2010, EPA promulgated its Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, to add new higher thresholds of 75,000 tons per year carbon dioxide equivalents for modifications and 100,000 tons per year carbon dioxide equivalents for new sources.

Additionally, on October 30, 2009, EPA promulgated a final mandatory greenhouse gas reporting rule which will assist EPA in developing policy approaches to greenhouse gas regulation. This reporting rule, which requires annual reporting of greenhouse gas emissions from affected sources, became effective on December 29, 2009. On November 30, 2010, EPA promulgated additional mandatory greenhouse gas reporting rules that specifically extended the annual reporting requirement to oil and natural gas production, with reporting for calendar year 2011 emissions due in September 2012.

Though under review by the D.C. Circuit, EPA s greenhouse gas rules promulgated thus far have survived petitions for stay, and are currently final and effective, and will remain so unless vacated or remanded by the court, or unless Congress adopts legislation preempting EPA s regulatory authority to address greenhouse gases under the CAA.

In May 2012, EPA adopted final New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAPs) for the upstream and midstream oil and natural gas industries. Specifically, EPA s rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The rules also establish specific new requirements regarding emissions from compressors, dehydrators, storage tanks and other well completion and production equipment, including requirements for so-called green completions beginning no later than 2015. In addition, the rules establish new leak detection requirements for natural gas processing plants. Compliance with these rules

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could result in significant costs, including increased capital expenditures and operating costs, and thereby adversely impact our business.

Beyond legislative and regulatory developments, there have been several recent court cases impacting this area of risk related to greenhouse gas emissions. The decisions in these cases may expose us, as potentially an emitter of significant direct and indirect emission sources of greenhouse gases, to similar litigation risk.

Other nations have already agreed to regulate emissions of greenhouse gases pursuant to the United Nations Framework Convention on Climate Change, also known as the Kyoto Protocol, an international treaty pursuant to which participating countries (not including the United States) agreed to reduce their emissions of greenhouse gases to below 1990 levels by 2012. Though the 16th meeting of the Council of the Parties in Mexico in November and December 2010 did not produce a legally binding final agreement, international negotiations continue, with the participation of the United States.

International developments, passage of state or federal climate control legislation or other regulatory initiatives, the implementation of regulations by EPA and analogous state agencies that restrict emissions of greenhouse gases in areas in which we conduct business, or further development of case law allowing claims based upon greenhouse gas emissions could have an adverse effect on our operations and financial condition as a result of material increases in operating and production costs and litigation expense due to expenses associated with monitoring, reporting, permitting and controlling greenhouse gas emissions or litigating claims related to emissions of greenhouse gases, and material decreases in the demand for oil and natural gas.

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

We utilize hydraulic fracturing as a means to enhance the productive capability of our wells. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Congress has at various times considered legislation to amend the federal Safe Drinking Water Act to require permits for hydraulic fracturing or require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Sponsors of bills previously proposed before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. That proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, these bills, if adopted, could repeal the exemptions for hydraulic fracturing from the Safe Drinking Water Act. These legislative efforts, however, have largely halted while EPA studies the issue of hydraulic fracturing. In 2010, EPA initiated a Hydraulic Fracturing Research Study to address concerns that hydraulic fracturing may affect the safety of drinking water. As part of that process, EPA requested and received information from the major fracturing service providers regarding the chemical composition of fluids, standard operating procedures and the sites where they engage in hydraulic fracturing. In February 2011, EPA released its Draft Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources, proposing to study the lifecycle of hydraulic fracturing fluid and providing a comprehensive list of chemicals identified in fracturing fluid and flowback/produced water. Interim results of this study are expected by the end of 2012, with the final results of the study expected in 2014. These developments, as well as increased scrutiny of hydraulic fracturing activities by state authorities, may result in additional levels of regulation or level of complexity with respect to existing regulation at the federal and state levels that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing, which could result in limiting the productive capability of future wells in which we likely would utilize hydraulic fracturing and increase our costs of compliance and doing business.

Our identified drilling location inventories are scheduled to be drilled over several years, making them susceptible to uncertainties that could eliminate certain proposed drilling locations or materially delay the timing of their drilling.

Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including the availability and cost of capital, seasonal conditions, regulatory approvals, natural gas and oil prices, drilling and completion costs and drilling results. Because of these uncertainties, we do not know if all the numerous potential drilling locations we have identified and plan to drill ultimately will be drilled or if we will be able to produce oil or natural gas economically from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

Limitations on the availability of drilling rigs, fracture stimulation crews and other field services in the Bakken Shale in North Dakota and Montana could adversely affect our ability to execute our development plans on a timely basis.

Operators have experienced limitations in the availability of drilling rigs, services for pressure pumping and other services required for well completion in the Bakken Shale in North Dakota and Montana. During 2011, GeoResources experienced substantial delays between drilling and completion of many of its operated and non-operated wells in the Williston Basin. Although timing between drilling and well completion improved, continued increases in drilling activity could result in delays. Increased delays could adversely affect production and reserve replacement, which could have a material adverse effect on our business, financial condition, results of operations and cash flows. The lack of availability of these types of services may cause delays in our development and production operations and could cause us to incur additional expenditures above what we have budgeted for those services. We cannot predict the magnitude or length of the shortages for these services, but should demand for them persist or increase, the cost of these services will likely increase, while at the same time the quality of these services may suffer, which could have a material adverse effect on our business, cash flows, financial condition and results of operations.

We may not be able to successfully integrate the businesses of the Company and GeoResources.

The success of the GeoResources merger depends in large part upon our ability to integrate the Company s and GeoResources organizations, operations, systems and personnel. The integration of two previously independent companies is a challenging, time-consuming and costly process. The Company and GeoResources have operated independently. It is possible that the integration process could result in the loss of key employees, the disruption of each company s ongoing businesses or inconsistencies in standards, controls, procedures and policies that adversely affect our ability to maintain relationships with suppliers, customers and employees or to achieve the anticipated benefits of the GeoResources merger. In addition, successful integration of the companies will require the dedication of significant management resources, which will temporarily detract attention from the day-to-day businesses of the combined company. If we are not able to integrate our organizations, operations, systems and personnel in a timely and efficient manner, the anticipated benefits of the GeoResources merger may not be realized fully or at all or may take longer to realize than expected.

We will only have limited recourse against the sellers of the Williston Basin Assets for losses and liabilities arising or discovered after the closing of the acquisition.

Under the terms of the reorganization and interest purchase agreement with the sellers of the Williston Basin Assets, we will have only limited recourse against the sellers for losses and liabilities arising or discovered after closing of the acquisition. We have limited indemnification rights in the event of a breach of a representation or warranty by the sellers, any environmental defect, a breach of a covenant by the sellers and certain third party costs related to title defects. We also have limited indemnification rights and limited rights to assert title defects or environmental defects, and any claims for such defects not timely asserted by us are deemed waived.

The representations and warranties provided by the sellers of the Williston Basin Assets are limited as to scope and in several cases, qualified by knowledge and materiality. In most cases, we must bring any claims for indemnification for a breach of a representation or warranty not involving title defects within 12 months of the closing. Indemnification claims are subject to an individual claim threshold of $75,000 and an aggregate claim threshold equal to 0.5% of the purchase price, or $7.25 million based on a purchase price of $1.45 billion, and our right of recovery is limited to 10% of the purchase price in many cases. We have conducted and will continue to conduct prior to closing customary due diligence of the Williston Basin Assets, including as to title and due diligence matters for which purchase price adjustments may be made, but there is no assurance that our due diligence will uncover all events or conditions that might negatively affect the value of the assets within such time periods. The total amount of title and environmental defect claims must be more than 0.5% of the purchase price, or $7.25 million, before we will be entitled to an adjustment to the purchase price consideration.

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

In connection with its acquisition of the East Texas Assets described Note 4 to the condensed consolidated financial statements, Halcón issued a total of 20,769,869 shares of its common stock, at a value of $9.00 per share, in the following transactions:

- On August 1, 2012, Halcón issued 16,460,316 shares of its common stock to CH4 Energy II, LLC, PetroMax Leon, LLC, and Petro Texas LLC, representing the stock component of consideration paid to such parties for their interests in the East Texas Assets.

- On August 2, 2012, Halcón issued 4,309,553 shares of its common stock to U.S. King King LLC, representing the stock component of consideration paid to U.S. King King LLC and Amerril Energy LLC for their interests in the East Texas Assets.

The shares of Halcón common stock were issued to selling parties in private placements pursuant to the exemptions from registration provided in Regulation D, Rule 506, under Section 4(2) of the Securities Act of 1933, as amended.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

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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.

Exhibit No.	Description
1.1	Underwriting Agreement, dated September 12, 2012, among the Company and EnCap Energy Capital Fund VIII, L.P. and Barclays Capital, Inc., Goldman, Sachs & Co., and J.P. Morgan Securities LLC, as representatives of the underwriters named therein (Incorporated by reference to Exhibit 1.1 of our Current Report on Form 8-K filed September 18, 2012).
2.1	Agreement and Plan of Merger, dated as of April 24, 2012 by and among Halcón Resources Corporation, Leopard Sub I, Inc., Leopard Sub II, LLC and GeoResources, Inc. (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed April 25, 2012).
2.2	Agreement of Sale and Purchase dated May 8, 2012 between NCL Appalachian Partners, L.P., as Seller, and Halcón Energy Properties, Inc., as Buyer (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed July 2, 2012).
2.3	Purchase and Sale Agreement dated as of the 5th day of June, 2012, among CH4 Energy II, LLC, PetroMax Leon, LLC and Petro Texas LLC and Halcón Energy Properties, Inc., and joined by PetroMax Operating Co., Inc. (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed August 7, 2012).
2.4	Reorganization and Interest Purchase Agreement dated October 19, 2012 by and among Halcón Energy Properties, Inc., Petro-Hunt, L.L.C. and Pillar Energy, LLC (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed October 22, 2012).
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).
3.1.1	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).
3.1.2	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).
3.2	Third Amended and Restated Bylaws of Halcón Resources Corporation (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed August 2, 2012).
4.1	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).
4.2	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).
4.3	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).

4.4	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).

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4.5	Registration Rights Agreement dated as of the 1st day of August, 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).
10.1	Halcón Resources Corporation 2012 Long-Term Incentive Plan effective May 17, 2012 (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed May 22, 2012).
10.2	Employment Agreement between Floyd C. Wilson and Halcón Resources Corporation dated June 1, 2012 (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed June 5, 2012).
10.3	Employment Agreement between Stephen W. Herod and Halcón Resources Corporation dated June 1, 2012 (Incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed June 5, 2012).
10.4	Employment Agreement between Mark J. Mize and Halcón Resources Corporation dated June 1, 2012 (Incorporated by reference to Exhibit 10.3 of our Current Report on Form 8-K filed June 5, 2012).
10.5	Employment Agreement between David S. Elkouri and Halcón Resources Corporation dated June 1, 2012 (Incorporated by reference to Exhibit 10.4 of our Current Report on Form 8-K filed June 5, 2012).
10.6	Employment Agreement between Joseph S. Rinando, III and Halcón Resources Corporation dated June 1, 2012 (Incorporated by reference to Exhibit 10.5 of our Current Report on Form 8-K filed June 5, 2012).
10.7	Form of Stock Option Award Agreement (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed June 13, 2012).
10.8	Form of Employee Restricted Stock Agreement (Incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed June 13, 2012).
10.9	Form of Non-Employee Director Restricted Stock Agreement (Incorporated by reference to Exhibit 10.3 of our Current Report on Form 8-K filed June 13, 2012).
10.10	Escrow Agreement, dated as of July 16, 2012, by and among Halcón Resources Corporation, U.S. Bank National Association, as trustee under the Indenture, and U.S. Bank National Association, as escrow and paying agent (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed July 17, 2012).
10.11	First Amendment to Senior Revolving Credit Agreement, dated as of August 1, 2012, among Halcón Resources Corporation, as borrower, each of the lenders from time to time 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 August 2, 2012).
10.12 *	Employment Agreement between Robert J. Anderson and Halcón Resources Corporation dated August 1, 2012, filed herewith.
10.13	Common Stock Purchase Agreement dated October 19, 2012, by and between Halcón Resources Corporation and CPP Investment Board PMI-2 Inc. (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed October 22, 2012)
31.1*	Rule 13(A) 14(A) Certification of our Principal Executive Officer
31.2*	Rule 13(A) 14(A) Certification of our Principal Financial Officer
32.1*	Section 1350 Certification of our Principal Executive Officer
32.2*	Section 1350 Certification of our Principal Financial Officer
101.INS*	XBRL Instance Document

101.SCH*	XBRL Taxonomy Extension Schema Document

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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

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* Attached hereto.
Indicates management contract or compensatory plan or arrangement

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SIGNATURES

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

HALCÓN RESOURCES CORPORATION

November 8, 2012	By:	/s/ Floyd C. Wilson
	Name:	Floyd C. Wilson
	Title:	*Chairman of the Board and Chief Executive Officer*
November 8, 2012	By:	/s/ Mark J. Mize
	Name:	Mark J. Mize
	Title:	*Executive Vice President and Chief Financial Officer*
November 8, 2012	By:	/s/ Joseph S. Rinando, III
	Name:	Joseph S. Rinando, III
	Title:	*Vice President and Chief Accounting Officer*