CONCHO RESOURCES INC
Form 10-Q
November 07, 2013

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2013

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: 1-33615

Concho Resources Inc.

(Exact name of registrant as specified in its charter)

Delaware	**76-0818600**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
One Concho Center 600 West Illinois Avenue Midland, Texas	**79701**

(Address of principal executive offices)	(Zip code)

(432) 683-7443
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ 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 þ 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 þ	Accelerated filer o
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 þ

Number of shares of the registrant's common stock outstanding at November 4, 2013: 105,061,575 shares

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in or incorporated by reference into this report that express a belief, expectation, or intention, or that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 (the “Securities Act”) and Section 21E of the Securities Exchange Act of 1934 (the “Exchange Act”). These forward-looking statements include statements, projections and estimates concerning our operations, performance, business strategy, oil and natural gas reserves, drilling program, capital expenditures, liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, derivative activities and potential financing. Forward-looking statements are generally accompanied by words such as “estimate,” “project,” “predict,” “believe,” “expect,” “anticipate,” “potential,” “could,” “may,” “foresee,” “plan,” words that convey the uncertainty of future events or outcomes. Forward-looking statements are not guarantees of performance. We have based these forward-looking statements on our current expectations and assumptions about future events. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. Actual results may differ materially from those implied or expressed by the forward-looking statements. These forward-looking statements speak only as of the date of this report, or if earlier, as of the date they were made. We disclaim any obligation to update or revise these statements unless required by law, and we caution you not to rely on them unduly. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties relating to, among other matters, the risks discussed in our Annual Report on Form 10-K for the year ended December 31, 2012 and in this report, as well as those factors summarized below:

- declines in the prices we receive for our oil and natural gas;

- uncertainties about the estimated quantities of oil and natural gas reserves;

- drilling and operating risks, including risks related to properties where we do not serve as the operator and risks related to hydraulic fracturing activities;

- the adequacy of our capital resources and liquidity including, but not limited to, access to additional borrowing capacity under our credit facility;

- the effects of government regulation, permitting and other legal requirements, including new legislation or regulation of hydraulic fracturing;

- difficult and adverse conditions in the domestic and global capital and credit markets;

- risks related to the concentration of our operations in the Permian Basin of Southeast New Mexico and West Texas;

- shortages of oilfield equipment, supplies, services and qualified personnel and increased costs for such equipment, supplies, services and personnel;

- potential financial losses or earnings reductions from our commodity price management program;

- risks and liabilities associated with acquired properties or businesses;

- uncertainties about our ability to successfully execute our business and financial plans and strategies;
- uncertainties about our ability to replace reserves and economically develop our current reserves;
- general economic and business conditions, either internationally or domestically;
- competition in the oil and natural gas industry; and
- uncertainty concerning our assumed or possible future results of operations.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by our reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ from the quantities of oil and natural gas that are ultimately recovered.

PART I – FINANCIAL INFORMATION

Item 1. Consolidated Financial Statements (Unaudited)

Concho Resources Inc.
Consolidated Balance Sheets
Unaudited

(in thousands, except share and per share amounts)	**September 30, 2013**	**December 31, 2012**
Assets		
Current assets:		
Cash and cash equivalents	$ 22	$ 2,880
Accounts receivable, net of allowance for doubtful accounts:		
Oil and natural gas	277,045	198,053
Joint operations and other	277,286	202,738
Derivative instruments	872	35,942
Deferred income taxes	33,150	-
Prepaid costs and other	19,337	19,269
Total current assets	607,712	458,882
Property and equipment:		
Oil and natural gas properties, successful efforts method	10,852,246	9,455,599
Accumulated depletion and depreciation	(2,176,041)	(1,565,316)
Total oil and natural gas properties, net	8,676,205	7,890,283
Other property and equipment, net	111,705	103,141
Total property and equipment, net	8,787,910	7,993,424
Funds held in escrow	1,964	-
Deferred loan costs, net	76,377	77,609
Intangible asset - operating rights, net	28,980	30,076
Inventory	19,894	20,611
Noncurrent derivative instruments	-	2,769
Other assets	7,864	6,066
Total assets	$ 9,530,701	$ 8,589,437
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable:		
Trade	$ 36,813	$ 31,144
Related parties	-	185
Bank overdrafts	69,444	24,275
Revenue payable	194,008	162,073
Accrued and prepaid drilling costs	323,928	351,919
Derivative instruments	71,364	1,584
Deferred income taxes	-	8,566
Other current liabilities	178,727	160,340
Total current liabilities	874,284	740,086
Long-term debt	3,588,650	3,101,103
Deferred income taxes	1,302,249	1,186,621
Noncurrent derivative instruments	24,049	12,049
Asset retirement obligations and other long-term liabilities	96,756	83,382
Commitments and contingencies (Note J)		
Stockholders' equity:		

Common stock, $0.001 par value; 300,000,000 authorized; 105,194,283 and 104,668,427 shares issued at September 30, 2013 and December 31, 2012, respectively		105		105
Additional paid-in capital		2,019,540		1,982,714
Retained earnings		1,635,777		1,490,563
Treasury stock, at cost; 125,580 and 86,861 shares at September 30, 2013 and December 31, 2012, respectively		(10,709)		(7,186)
Total stockholders' equity		3,644,713		3,466,196
Total liabilities and stockholders' equity	$	9,530,701	$	8,589,437

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

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Concho Resources Inc.
Consolidated Statements of Operations
Unaudited

(in thousands, except per share amounts)	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Operating revenues:				
Oil sales	$ 553,068	$ 380,446	$ 1,412,887	$ 1,099,504
Natural gas sales	99,852	84,897	274,946	242,784
Total operating revenues	652,920	465,343	1,687,833	1,342,288
Operating costs and expenses:				
Oil and natural gas production	120,231	87,964	328,295	251,641
Exploration and abandonments	10,992	6,958	37,797	27,335
Depreciation, depletion and amortization	200,625	148,145	557,775	408,675
Accretion of discount on asset retirement obligations	1,574	1,084	4,410	2,826
Impairments of long-lived assets	-	-	65,375	-
General and administrative (including non-cash stock-based compensation of $9,923 and $7,959 for the three months ended September 30, 2013 and 2012, respectively, and $25,278 and $21,434 for the nine months ended September 30, 2013 and 2012, respectively)	40,836	35,492	125,120	95,994
(Gain) loss on derivatives not designated as hedges	168,610	135,415	157,303	(109,542)
Total operating costs and expenses	542,868	415,058	1,276,075	676,929
Income from operations	110,052	50,285	411,758	665,359
Other income (expense):				
Interest expense	(55,995)	(51,337)	(162,180)	(129,073)
Loss on extinguishment of debt	-	-	(28,616)	-
Other, net	(1,941)	(3,114)	(1,806)	(4,917)
Total other expense	(57,936)	(54,451)	(192,602)	(133,990)
Income (loss) from continuing operations before income taxes	52,116	(4,166)	219,156	531,369
Income tax (expense) benefit	(21,695)	995	(86,023)	(204,327)

Income (loss) from continuing operations		30,421		(3,171)		133,133		327,042
Income from discontinued operations, net of tax		-		9,159		12,081		29,360
Net income	$	30,421	$	5,988	$	145,214	$	356,402
Basic earnings per share:								
Income (loss) from continuing operations	$	0.29	$	(0.03)	$	1.27	$	3.17
Income from discontinued operations, net of tax		-		0.09		0.12		0.29
Net income	$	0.29	$	0.06	$	1.39	$	3.46
Diluted earnings per share:								
Income (loss) from continuing operations	$	0.29	$	(0.03)	$	1.27	$	3.15
Income from discontinued operations, net of tax		-		0.09		0.11		0.28
Net income	$	0.29	$	0.06	$	1.38	$	3.43

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

Concho Resources Inc.
Consolidated Statement of Stockholders' Equity
Unaudited

(in thousands)	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings	Treasury Stock Shares	Treasury Stock Amount	Total Stockholders' Equity
BALANCE AT DECEMBER 31, 2012	104,668	$ 105	$ 1,982,714	$ 1,490,563	87	$ (7,186)	$ 3,466,196
Net income	-	-	-	145,214	-	-	145,214
Stock options exercised	139	-	2,304	-	-	-	2,304
Grants of restricted stock	484	-	-	-	-	-	-
Cancellation of restricted stock	(97)	-	-	-	-	-	-
Stock-based compensation	-	-	25,278	-	-	-	25,278
Excess tax benefits related to stock-based compensation	-	-	9,244	-	-	-	9,244
Purchase of treasury stock	-	-	-	-	39	(3,523)	(3,523)
BALANCE AT SEPTEMBER 30, 2013	105,194	$ 105	$ 2,019,540	$ 1,635,777	126	$ (10,709)	$ 3,644,713

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

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Concho Resources Inc.
Consolidated Statements of Cash Flows
Unaudited

	Nine Months Ended September 30,	
(in thousands)	**2013**	**2012**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 145,214	$ 356,402
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	557,775	408,675
Accretion of discount on asset retirement obligations	4,410	2,826
Impairments of long-lived assets	65,375	-
Exploration and abandonments, including dry holes	13,159	15,224
Non-cash stock-based compensation expense	25,278	21,434
Deferred income taxes	75,808	203,107
Loss on disposition of assets, net	1,717	285
(Gain) loss on derivatives not designated as hedges	157,303	(109,542)
Discontinued operations	(12,250)	28,591
Other non-cash items	17,020	9,066
Changes in operating assets and liabilities, net of acquisitions and dispositions:		
Accounts receivable	(113,226)	(54,752)
Prepaid costs and other	(1,866)	(14,894)
Inventory	434	(8,528)
Accounts payable	4,407	(4,919)
Revenue payable	44,983	(3,673)
Other current liabilities	(40,897)	(3,666)
Net cash provided by operating activities	944,644	845,636
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures on oil and natural gas properties	(1,426,349)	(2,334,246)
Additions to other property and equipment	(21,311)	(47,489)
Proceeds from the disposition of assets	15,212	4,419
Funds held in escrow	(1,964)	17,394
Settlements paid on derivatives not designated as hedges	(37,684)	(7,485)
Net cash used in investing activities	(1,472,096)	(2,367,407)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from issuance of debt	3,283,875	3,856,500
Payments of debt	(2,798,400)	(2,336,000)
Exercise of stock options	2,304	8,062
Excess tax benefit from stock-based compensation	9,244	18,522
Payments for loan costs	(14,075)	(23,926)
Purchase of treasury stock	(3,523)	(2,721)
Bank overdrafts	45,169	1,283
	524,594	1,521,720

Net cash provided by financing activities		
Net decrease in cash and cash equivalents	(2,858)	(51)
Cash and cash equivalents at beginning of period	2,880	342
Cash and cash equivalents at end of period	$ 22	$ 291

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

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Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2013

Unaudited

Note A. ***Organization and nature of operations***

Concho Resources Inc. (the “Company”) is a Delaware corporation formed on February 22, 2006. The Company’s principal business is the acquisition, development and exploration of oil and natural gas properties primarily located in the Permian Basin region of Southeast New Mexico and West Texas.

Note B. ***Summary of significant accounting policies***

Principles of consolidation. The consolidated financial statements of the Company include the accounts of the Company and its wholly-owned subsidiaries. The Company consolidates the financial statements of these entities. All material intercompany balances and transactions have been eliminated.

Use of estimates in the preparation of financial statements. Preparation of financial statements in conformity with generally accepted accounting principles in the United States of America (“U.S. GAAP”) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from these estimates. Depletion of oil and natural gas properties is determined using estimates of proved oil and natural gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. Similarly, evaluations for impairment of proved and unproved oil and natural gas properties are subject to numerous uncertainties including, among others, estimates of future recoverable reserves and commodity price outlooks. Other significant estimates include, but are not limited to, the asset retirement obligations, fair value of derivative financial instruments, fair value measurements for business combinations and fair value of stock-based compensation.

Interim financial statements. The accompanying consolidated financial statements of the Company have not been audited by the Company’s independent registered public accounting firm, except that the consolidated balance sheet at December 31, 2012 is derived from audited consolidated financial statements. In the opinion of management, the accompanying consolidated financial statements reflect all adjustments necessary to present fairly the Company’s consolidated financial statements. All such adjustments are of a normal, recurring nature. In preparing the accompanying consolidated financial statements, management has made certain estimates and assumptions that affect reported amounts in the consolidated financial statements and disclosures of contingencies. Actual results may differ from those estimates. The results for interim periods are not necessarily indicative of annual results.

Certain disclosures have been condensed in or omitted from these consolidated financial statements. Accordingly, these condensed consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes included in the Company's Annual Report on Form 10-K for the year ended December 31, 2012.

Earnings per share. The Company grants non-vested restricted stock awards that meet the definition of a participating security. The Company calculates earnings per share ("EPS") using the two-class method.

Deferred loan costs. Deferred loan costs are stated at cost, net of amortization, which is computed using the effective interest and straight-line methods. The Company had deferred loan costs of $76.4 million and $77.6 million, net of accumulated amortization of $45.4 million and $38.8 million, at September 30, 2013 and December 31, 2012, respectively.

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2013

Unaudited

Future amortization expense of deferred loan costs at September 30, 2013 was as follows:

(in thousands)		
Remaining 2013	$	3,329
2014		13,503
2015		13,820
2016		8,476
2017		5,994
2018		6,376
Thereafter		24,879
Total	$	76,377

Intangible assets. The Company has capitalized certain operating rights acquired in an acquisition. The gross operating rights, which have no residual value, are amortized over the estimated economic life of 25 years. Impairment will be assessed if indicators of potential impairment exist or when there is a material change in the remaining useful economic life. The following table reflects the gross and net intangible assets at September 30, 2013 and December 31, 2012:

(in thousands)		**September 30, 2013**		**December 31, 2012**
Gross intangible - operating rights	$	36,557	$	36,557
Accumulated amortization		(7,577)		(6,481)
Net intangible - operating rights	$	28,980	$	30,076

The following table reflects amortization expense from continuing and discontinued operations for the three and nine months ended September 30, 2013 and 2012:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	**2013**	**2012**	**2013**	**2012**
Amortization expense	$ 365	$ 388	$ 1,096	$ 1,162

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Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2013

Unaudited

The following table reflects the estimated aggregate amortization expense for each of the periods presented below at September 30, 2013:

(in thousands)		
Remaining 2013	$	365
2014		1,461
2015		1,461
2016		1,461
2017		1,461
2018		1,461
Thereafter		21,310
Total	$	28,980

Oil and natural gas sales and imbalances. Oil and natural gas revenues are recorded at the time of delivery to pipelines for the account of the purchaser or at the time of physical transfer to the purchaser. The Company follows the sales method of accounting for oil and natural gas sales, recognizing revenues based on the Company's share of actual proceeds from the oil and natural gas sold to purchasers. Oil and natural gas imbalances are generated on properties for which two or more owners have the right to take production "in-kind" and, in doing so, take more or less than their respective entitled percentage. Imbalances are tracked by well, but the Company does not record any receivable from or payable to the other owners unless the imbalance has reached a level at which it exceeds the remaining reserves in the respective well. If reserves are insufficient to offset the imbalance and the Company is in an overtake position, a liability is recorded for the amount of shortfall in reserves valued at a contract price or the market price in effect at the time the imbalance is generated. If the Company is in an undertake position, a receivable is recorded for an amount that is reasonably expected to be received, not to exceed the current market value of such imbalance. The Company has no material recorded or unrecorded imbalances.

Treasury stock. Treasury stock purchases are recorded at cost. Upon reissuance, the cost of treasury shares held is reduced by the average purchase price per share of the aggregate treasury shares held.

***General and administrative expense*.** The Company receives fees for the operation of jointly-owned oil and natural gas properties and records such reimbursements as reductions of general and administrative expense. Such fees from continuing and discontinued operations totaled approximately $4.2 million and $4.4 million for the three months ended September 30, 2013 and 2012, respectively, and $13.5 million and $12.5 million for the nine months ended September 30, 2013 and 2012, respectively.

***Reclassifications*.** Certain prior period amounts have been reclassified to conform to the 2013 presentation. These reclassifications had no impact on net income, total stockholders' equity or cash flows.

Recent accounting pronouncements. In December 2011, the Financial Accounting Standards Board (the "FASB") issued amendments that require enhanced disclosure regarding financial instruments and derivative instruments that are either (i) offset in accordance with the current definition of "right of setoff" or the current balance sheet netting for derivative instruments allowed under current U.S. GAAP or (ii) subject to an enforceable master netting arrangement or similar

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2013

Unaudited

agreement. The Company adopted this update on January 1, 2013, and the update did not have a significant impact on the consolidated financial statements.

Note C. ***Exploratory well costs***

The Company capitalizes exploratory well costs until a determination is made that the well has either found proved reserves or that it is impaired. After an exploratory well has been completed and found oil and natural gas reserves, a determination may be pending as to whether the oil and natural reserves can be classified as proved. In those circumstances, the Company continues to capitalize the well or project costs pending the determination of proved status if (i) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (ii) the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. The capitalized exploratory well costs are carried in unproved oil and natural gas properties. See Note R for the proved and unproved components of oil and natural gas properties. If the exploratory well is determined to be impaired, the well costs are charged to expense.

The following table reflects the Company's capitalized exploratory well activity during the three and nine months ended September 30, 2013:

(in thousands)		**Three Months Ended September 30, 2013**		**Nine Months Ended September 30, 2013**
Beginning capitalized exploratory well costs	$	180,433	$	118,806
Additions to exploratory well costs pending the determination of proved reserves		262,743		806,327
Reclassifications due to determination of proved reserves		(270,461)		(752,349)
Exploratory well costs charged to expense		-		(69)
Ending capitalized exploratory well costs	$	172,715	$	172,715

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Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2013

Unaudited

The following table provides an aging at September 30, 2013 and December 31, 2012 of capitalized exploratory well costs based on the date drilling was completed:

(in thousands)		**September 30, 2013**		**December 31, 2012**
Exploratory wells in progress	$	27,176	$	22,837
Capitalized exploratory well costs that have been capitalized for a period of one year or less		124,464		95,969
Capitalized exploratory well costs that have been capitalized for a period greater than one year		21,075		-
Total capitalized exploratory well costs	$	172,715	$	118,806

Northern Midland Basin project. At September 30, 2013, the Company had approximately $6.3 million of suspended well costs greater than one year recorded for the first well in the Company's Northern Midland Basin project. The Company is currently in the process of drilling a second well to continue to evaluate the viability of this project.

Southern Delaware Basin projects. At September 30, 2013, the Company had approximately $9.5 million of suspended well costs greater than one year recorded for two vertical wells where multiple zones are being evaluated in the Company's Southern Delaware Basin project. The Company is assessing options to drill horizontal laterals to continue evaluation of the targets.

Other projects. At September 30, 2013, the Company had approximately $5.3 million of suspended well costs greater than one year recorded for three wells that have encountered technical difficulties that the Company plans to recomplete.

Exploratory well counts. At September 30, 2013, the Company had 75 gross exploratory wells either drilling or waiting on results from completion and testing, of which 20 wells were in the Delaware Basin area, 28 wells were in the Texas Permian area and 27 wells were in the New Mexico Shelf area.

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2013

Unaudited

Note D. ***Acquisitions***

Three Rivers Acquisition. In July 2012, the Company acquired certain producing and non-producing assets from Three Rivers Operating Company LLC and certain affiliated entities (the "Three Rivers Acquisition") for cash consideration of approximately $1.0 billion. The Three Rivers Acquisition was primarily funded with borrowings under the Company's credit facility. The Company's results of operations prior to July 2012 do not include results from the Three Rivers Acquisition.

The following table reflects the fair value of the acquired asset and liabilities with the Three Rivers Acquisition:

(in thousands)		
Fair value of net assets:		
Proved oil and natural gas properties	$	683,482
Unproved oil and natural gas properties		359,109
Total assets acquired		1,042,591
Current liabilities, including current portion of asset retirement obligations		(2,229)
Asset retirement obligations assumed		(26,002)
Fair value of net assets acquired	$	1,014,360
Fair value of consideration paid for net assets:		
Cash consideration	$	1,014,360

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2013

Unaudited

PDC Acquisition. In February 2012, the Company acquired certain producing and non-producing assets from Petroleum Development Corporation (the "PDC Acquisition") for cash consideration of approximately $189.2 million. The PDC Acquisition was primarily funded with borrowings under the Company's credit facility. The Company's results of operations prior to March 2012 do not include results from the PDC Acquisition.

The following table reflects the fair value of the acquired assets and liabilities associated with the PDC Acquisition:

(in thousands)		
Fair value of net assets:		
Current assets	$	2,366
Proved oil and natural gas properties		159,314
Unproved oil and natural gas properties		29,687
Total assets acquired		191,367
Current liabilities		(123)
Asset retirement obligations assumed		(2,050)
Fair value of net assets acquired	$	189,194
Fair value of consideration paid for net assets:		
Cash consideration	$	189,194

Pro forma data. The following unaudited pro forma combined condensed financial data for the nine months ended September 30, 2012, were derived from the historical financial statements of the Company giving effect to the Three Rivers Acquisition, as if it had occurred on January 1, 2012. The results of operations since the closing of the Three Rivers Acquisition in July 2012 are included in the Company's results of operations. The pro forma financial data does not include the results of operations for the PDC Acquisition, as the results of operations were deemed not to be material. The unaudited pro forma combined condensed financial data has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the Three Rivers Acquisition taken place as of the date indicated and is not intended to be a projection of future results.

(in thousands, except per share amounts)		Nine Months Ended September 30, 2012 (unaudited)
Operating revenues	$	1,408,295
Net income	$	336,712
Earnings per common share:		
Basic	$	3.27
Diluted	$	3.24

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2013

Unaudited

Note E. ***Asset retirement obligations***

The Company's asset retirement obligations represent the estimated present value of the estimated cash flows the Company will incur to plug, abandon and remediate its producing properties at the end of their productive lives, in accordance with applicable state laws. The Company does not provide for a market risk premium associated with asset retirement obligations because a reliable estimate cannot be determined. The Company has no assets that are legally restricted for purposes of settling asset retirement obligations.

The Company's asset retirement obligation transactions during the three and nine months ended September 30, 2013 and 2012 are summarized in the table below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	**2013**	**2012**	**2013**	**2012**
Asset retirement obligations, beginning of period	$ 96,347	$ 68,089	$ 86,261	$ 59,685
Liabilities incurred from new wells	1,775	3,053	5,024	6,319
Liabilities assumed in acquisitions	-	26,986	282	29,113
Accretion expense for continuing operations	1,574	1,084	4,410	2,826
Accretion expense for discontinued operations	-	336	-	629
Disposition of wells	-	-	(303)	(66)
Liabilities settled upon plugging and abandoning wells	(897)	(272)	(2,542)	(514)
Revision of estimates	561	3,151	6,228	4,435
Asset retirement obligations, end of period	$ 99,360	$ 102,427	$ 99,360	$ 102,427

Note F. ***Incentive plans***

Defined contribution plan. The Company sponsors a 401(k) defined contribution plan for the benefit of substantially all employees. Currently, the Company matches 100 percent of employee contributions, not to exceed 10 percent of the employee's annual salary. The Company's contributions to the plan for the three months ended September 30, 2013 and 2012 were approximately $1.3 million and $1.1 million, respectively, and approximately $3.7 million and $3.0 million for the nine months ended September 30, 2013 and 2012, respectively.

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Stock incentive plan. The Company's 2006 Stock Incentive Plan, as amended and restated (the "Plan"), provides for granting stock options, restricted stock awards and performance awards to employees and individuals associated with the Company. The following table shows the number of existing awards and awards available under the Plan at September 30, 2013:

	Number of Common Shares
Approved and authorized awards	7,500,000
Restricted stock grants, net of forfeitures	(2,368,907)
Stock option grants, net of forfeitures	(3,463,720)
Performance unit grants (a)	(332,667)
Treasury shares	125,580
Awards available for future grant	1,460,286

(a) This amount represents the 110,889 performance units granted multiplied by the maximum potential payout of 300 percent. The actual payout of shares may be between zero percent and 300 percent of the performance units granted depending on the Company's performance at the end of the performance period.

Restricted stock awards. All restricted shares are treated as issued and outstanding in the accompanying consolidated balance sheets. If an employee terminates employment prior to the restriction lapse date, the awarded shares are forfeited and cancelled and are no longer considered issued and outstanding. A summary of the Company's restricted stock award activity for the nine months ended September 30, 2013 is presented below:

	Number of Restricted Shares	Grant Date Fair Value

Restricted stock:			**Per Share**
Outstanding at December 31, 2012	1,072,527		
Shares granted	483,440	$	87.69
Shares cancelled / forfeited	(96,695)		
Lapse of restrictions	(220,710)		
Outstanding at September 30, 2013	1,238,562		

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The following table summarizes information about stock-based compensation for the Company's restricted stock awards activity under the Plan for the three and nine months ended September 30, 2013 and 2012:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	**2013**	**2012**	**2013**	**2012**
Grant date fair value for awards during the period: (a)				
Employee grants	$ 6,881	$ 1,180	$ 30,934	$ 27,306
Officer and director grants	-	290	12,445	18,521
Total	$ 6,881	$ 1,470	$ 43,379	$ 45,827
Stock-based compensation expense from restricted stock:				
Employee grants	$ 5,116	$ 3,854	$ 12,511	$ 9,617
Officer and director grants	3,778	4,077	9,701	11,653
Total	$ 8,894	$ 7,931	$ 22,212	$ 21,270
Income taxes and other information:				
Income tax benefit related to restricted stock	$ 3,399	$ 3,032	$ 8,491	$ 8,131
Deductions in current taxable income related to restricted stock	$ 2,302	$ 1,043	$ 15,847	$ 22,581

(a) The nine months ended September 30, 2013 includes the effects of $1 million due to modifications of certain stock-based awards.

Stock option awards. A summary of the Company's stock option award activity under the Plan for the nine months ended September 30, 2013 is presented below:

	Number of Options		Weighted Average Exercise Price
Stock options:			
Outstanding at December 31, 2012	429,879	$	20.28
Options exercised	(139,111)	$	16.57
Outstanding at September 30, 2013	290,768	$	22.05
Exercisable at end of period	290,768	$	22.05

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The following table summarizes information about the Company's exercisable stock options outstanding at September 30, 2013:

Range of Exercise Prices	Number Vested	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Intrinsic Value (in thousands)
Vested and exercisable options:				
$8.00	2,005	0.87 years	$ 8.00	$ 202
$12.00	23,788	2.07 years	$ 12.00	2,303
12.85	15,000	3.88 years	$ 12.85	1,439
$20.00 - $23.00	192,895	4.78 years	$ 21.40	16,862
$28.00 - $37.27	57,080	4.66 years	$ 31.34	4,422
	290,768	4.46 years	$ 22.05	$ 25,228

The following table summarizes information about stock-based compensation for stock options for the three and nine months ended September 30, 2013 and 2012:

(in thousands)	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
Stock-based compensation expense from stock options:				
Employee grants	$ -	$ 7	$ 2	$ 24
Officer and director grants	-	21	13	140
Total	$ -	$ 28	$ 15	$ 164

Income taxes and other information:				
Income tax benefit related to stock options	$ -	$ 10	$ 5	$ 63
Deductions in current taxable income related to stock options exercised	$ 1,797	$ 23,332	$ 10,317	$ 39,420

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Performance unit awards. During the nine months ended September 30, 2013, the Company awarded performance units to its officers under the Plan. The number of shares of common stock that will ultimately be issued will be determined by a combination of (i) comparing the Company's total shareholder return relative to the total shareholder return of a predetermined group of peer companies at the end of the performance period and (ii) the Company's absolute total shareholder return at the end of the performance period. The performance period is 36 months. The grant date fair value was determined using the Monte Carlo simulation method and is being expensed ratably over the performance period.

The Company used the following assumptions to estimate the fair value of performance unit awards granted during the nine months ended September 30, 2013:

Risk-free interest rate	0.37%
Range of volatilities	31.5% - 45.1%

The following table summarizes the performance unit activity for the nine months ended September 30, 2013:

	Number of Units (a)	Grant Date Fair Value
Performance units:		
Outstanding at December 31, 2012	-	
Units granted	110,889	$ 111.40
Outstanding at September 30, 2013	110,889	

(a) Reflects the amount of performance units granted. The actual payout of shares will be between zero and 300 percent of the performance units granted depending on the Company's performance at the end of the performance period.

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The following table summarizes information about stock-based compensation expense for performance units for the three and nine months ended September 30, 2013:

(in thousands)	**Three Months Ended September 30, 2013**	**Nine Months Ended September 30, 2013**
Grant date fair value for awards during the period:		
Officer grants	$ -	$ 12,353
Stock-based compensation expense from performance units:		
Officer grants	$ 1,029	$ 3,051
Income taxes:		
Income tax benefit related to performance units	$ 394	$ 1,167

Future stock-based compensation expense. The following table reflects the future stock-based compensation expense to be recorded for all the stock-based compensation awards that were outstanding at September 30, 2013:

(in thousands)	**Restricted Stock**	**Performance Units**	**Total**
Remaining 2013	$ 9,359	$ 1,029	$ 10,388
2014	27,262	4,118	31,380
2015	14,588	4,154	18,742
2016	5,245	-	5,245
2017	548	-	548
Total	$ 57,002	$ 9,301	$ 66,303

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Note G. ***Disclosures about fair value of financial instruments***

The Company uses a valuation framework based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources, whereas unobservable inputs reflect a company's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further prioritized into the following fair value input hierarchy:

Level 1**:** Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. The Company considers active markets to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2**:** Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that the Company values using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace. Level 2 instruments primarily include non-exchange traded derivatives such as over-the-counter commodity price swaps, basis swaps, collars and floors, investments and interest rate swaps. The Company's valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures.

Level 3**:** Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (*i.e.*, supported by little or no market activity). The Company's valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value, (iii) volatility factors and (iv) current market and contractual prices for the underlying instruments, as well as other relevant economic measures.

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Financial Assets and Liabilities Measured at Fair Value

The following table presents the carrying amounts and fair values of the Company's financial instruments at September 30, 2013 and December 31, 2012:

	September 30, 2013		December 31, 2012	
(in thousands)	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Assets:				
Derivative instruments	$ 872	$ 872	$ 38,711	$ 38,711
Liabilities:				
Derivative instruments	$ 95,413	$ 95,413	$ 13,633	$ 13,633
Credit facility	$ 207,600	$ 210,666	$ 304,000	$ 299,679
8.625% senior notes due 2017	$ -	$ -	$ 297,103	$ 323,471
7.0% senior notes due 2021	$ 600,000	$ 657,000	$ 600,000	$ 669,000
6.5% senior notes due 2022	$ 600,000	$ 643,500	$ 600,000	$ 660,000
5.5% senior notes due 2022	$ 600,000	$ 598,500	$ 600,000	$ 633,000
5.5% senior notes due 2023	$ 1,581,050	$ 1,530,625	$ 700,000	$ 733,250

Cash and cash equivalents, accounts receivable, other current assets, accounts payable, interest payable and other current liabilities. The carrying amounts approximate fair value due to the short maturity of these instruments.

Credit facility. The fair value of the Company's credit facility is estimated by discounting the principal and interest payments at the Company's credit-adjusted discount rate at the reporting date and is determined utilizing inputs that are Level 2 measurements in the fair value hierarchy.

Senior notes. The fair values of the Company's senior notes are based on quoted market prices. The debt securities are not actively traded and, therefore, are classified as Level 2 in the fair value hierarchy.

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Derivative instruments. The fair value of the Company's derivative instruments is estimated by management considering various factors, including closing exchange and over-the-counter quotations and the time value of the underlying commitments. Financial assets and liabilities are classified 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 the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The following table summarizes (i) the valuation of each of the Company's financial instruments by required fair value hierarchy levels and (ii) the gross fair value by the appropriate balance sheet classification, even when the derivative instruments are subject to netting arrangements and qualify for net presentation in the Company's consolidated balance sheets at September 30, 2013 and December 31, 2012. The Company nets the fair value of derivative instruments by counterparty in the Company's consolidated balance sheets.

	Fair Value Measurements Using					Net
(in thousands)	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total Fair Value at September 30, 2013**	**Gross Amounts Offset in the Consolidated Balance Sheet**	**Fair Value Presented in the Consolidated Balance Sheet**
Assets						
Current:(a)						
Commodity derivatives	$ -	$ 12,880	$ -	$ 12,880	$ (12,008)	$ 872
Noncurrent:(b)						
Commodity derivatives	-	4,600	-	4,600	(4,600)	-
Liabilities						
Current:(a)						
Commodity derivatives	-	(83,372)	-	(83,372)	12,008	(71,364)
Noncurrent:(b)						

Commodity derivatives	-	(28,649)	-	(28,649)	4,600	(24,049)
Net derivative instruments	$ -	$ (94,541)	$ -	$ (94,541)	$ -	$ (94,541)

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	Fair Value Measurements Using					Net
(in thousands)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value at December 31, 2012	Gross Amounts Offset in the Consolidated Balance Sheet	Fair Value Presented in the Consolidated Balance Sheet
Assets						
Current:(a)						
Commodity derivatives	$ -	$ 56,471	$ -	$ 56,471	$ (20,529)	$ 35,942
Noncurrent:(b)						
Commodity derivatives	-	12,108	-	12,108	(9,339)	2,769
Liabilities						
Current:(a)						
Commodity derivatives	-	(22,113)	-	(22,113)	20,529	(1,584)
Noncurrent:(b)						
Commodity derivatives	-	(21,388)	-	(21,388)	9,339	(12,049)
Net derivative instruments	$ -	$ 25,078	$ -	$ 25,078	$ -	$ 25,078

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Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis in the Company's consolidated balance sheets. The following methods and assumptions were used to estimate the fair values:

Impairments of long-lived assets – The Company reviews its long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. In this circumstance, the Company recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset. The Company reviews its oil and natural gas properties by depletion base or by individual well for those wells not constituting part of a depletion base. For each property determined to be impaired, an impairment loss equal to the difference between the carrying value of the properties and the estimated fair value (discounted future cash flows) of the properties would be recognized at that time. Estimating future cash flows involves the use of judgments, including estimation of the proved and unproved oil and natural gas reserve quantities, timing of development and production, expected future commodity prices, capital expenditures and production costs.

The Company periodically reviews its proved oil and natural gas properties for impairment. Impairment expense is caused primarily due to declines in commodity prices and well performance. The Company did not recognize impairment charges for the three months ended September 30, 2012 and 2013 or for the nine months ended September 30, 2012. The Company recognized impairment charges for the nine months ended September 30, 2013 as follows:

(in thousands)	**Carrying Amount**	**Estimated Fair Value (Level 3)**	**Impairment Expense**
Nine Months Ended September 30, 2013	$ 84,140	$ 18,765	$ 65,375

Note H. ***Derivative financial instruments***

The Company uses derivative financial instruments to manage its exposure to commodity price fluctuations. Commodity derivative instruments are used to (i) reduce the effect of the volatility of price changes on the oil and natural gas the Company produces and sells, (ii) support the Company's capital budget and expenditure plans and (iii) support the economics associated with acquisitions. The Company does not enter into derivative financial instruments for speculative or trading purposes. The Company may also enter into physical delivery contracts to effectively provide commodity price hedges. Because these contracts are not expected to be net cash settled, they are considered to be normal sales contracts and not derivatives. Therefore, these contracts are not recorded in the Company's consolidated financial statements.

The Company does not designate its derivative instruments to qualify for hedge accounting. Accordingly, the Company reflects changes in the fair value of its derivative instruments in its statements of operations as they occur.

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The following table summarizes the gains (losses) reported in earnings related to the commodity derivative instruments for the three and nine months ended September 30, 2013 and 2012:

(in thousands)	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Gain (loss) on derivatives not designated as hedges:				
Oil derivatives	$ (169,049)	$ (135,401)	$ (172,698)	$ 109,386
Natural gas derivatives	439	(14)	15,395	156
Total gain (loss) on derivatives not designated as hedges	$ (168,610)	$ (135,415)	$ (157,303)	$ 109,542

The following table represents the Company's cash receipts from (payments on) derivatives not designated as hedges for the three and nine months ended September 30, 2013 and 2012:

(in thousands)	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Cash receipts from (payments on) derivatives not designated as hedges:				
Oil derivatives	$ (49,864)	$ 15,859	$ (42,528)	$ (8,374)
Natural gas derivatives	4,589	280	4,844	889
Total cash receipts from (payments on) derivatives not designated as hedges	$ (45,275)	$ 16,139	$ (37,684)	$ (7,485)

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Commodity derivative contracts at September 30, 2013. The following table sets forth the Company's outstanding derivative contracts at September 30, 2013. When aggregating multiple contracts, the weighted average contract price is disclosed. All of the Company's derivative contracts at September 30, 2013 are expected to settle by June 30, 2017.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Swaps: (a)					
2013:					
Volume (Bbl)				4,614,000	4,614,000
Price per Bbl				$ 95.87	$ 95.87
2014:					
Volume (Bbl)	4,277,000	3,848,000	3,560,000	3,355,000	15,040,000
Price per Bbl	$ 93.31	$ 92.18	$ 90.61	$ 90.54	$ 91.76
2015:					
Volume (Bbl)	3,154,000	2,984,000	2,858,000	2,721,000	11,717,000
Price per Bbl	$ 87.24	$ 86.36	$ 86.66	$ 86.58	$ 86.72
2016:					
Volume (Bbl)	108,000	108,000	108,000	105,000	429,000
Price per Bbl	$ 88.32	$ 88.32	$ 88.32	$ 88.28	$ 88.31
2017:					
Volume (Bbl)	84,000	84,000	-	-	168,000
Price per Bbl	$ 87.00	$ 87.00	$ -	$ -	$ 87.00
Oil Basis Swaps: (b)					
2013:					

Volume (Bbl)				3,404,000	3,404,000
Price per Bbl				$ (1.12)	$ (1.12)
2014:					
Volume (Bbl)	2,790,000	2,821,000	1,932,000	1,932,000	9,475,000
Price per Bbl	$ (0.46)	$ (0.46)	$ (0.45)	$ (0.45)	$ (0.46)
Natural Gas Swaps: (c)					
2013:					
Volume (MMBtu)				6,992,000	6,992,000
Price per MMBtu				$ 4.25	$ 4.25
Natural Gas Collars: (d)					
2014:					
Volume (MMBtu)	5,400,000	5,460,000	5,520,000	5,520,000	21,900,000
Ceiling price per MMBtu	$ 4.40	$ 4.40	$ 4.40	$ 4.40	$ 4.40
Floor price per MMBtu	$ 3.85	$ 3.85	$ 3.85	$ 3.85	$ 3.85
Natural Gas Basis Swaps: (e)					
2013:					
Volume (MMBtu)				6,440,000	6,440,000
Price per MMBtu				$ (0.15)	$ (0.15)

(a) The index prices for the oil price swaps are based on the NYMEX – West Texas Intermediate (“WTI”) monthly average futures price.
(b) The basis differential price is between Midland – WTI and Cushing – WTI.
(c) The index prices for the natural gas price swaps are based on the NYMEX – Henry Hub last trading day futures price.
(d) The index prices for the natural gas collars are based on the El Paso Permian delivery point.
(e) The basis differential price is between the El Paso Permian delivery point and NYMEX – Henry Hub delivery point.

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Note I. ***Debt***

The Company’s debt consisted of the following at September 30, 2013 and December 31, 2012:

(in thousands)		**September 30, 2013**		**December 31, 2012**
Credit facility	$	207,600	$	304,000
8.625% unsecured senior notes due 2017		-		300,000
7.0% unsecured senior notes due 2021		600,000		600,000
6.5% unsecured senior notes due 2022		600,000		600,000
5.5% unsecured senior notes due 2022		600,000		600,000
5.5% unsecured senior notes due 2023		1,550,000		700,000
Unamortized original issue premium (discount), net		31,050		(2,897)
Less: current portion		-		-
Total long-term debt	$	3,588,650	$	3,101,103

Credit facility. The Company’s credit facility, as amended (the “Credit Facility”), has a maturity date of April 25, 2016. The Company’s borrowing base is $3.0 billion until the next scheduled borrowing base redetermination in April 2014, and commitments from the Company’s bank group total $2.5 billion. Between scheduled borrowing base redeterminations, the Company and the lenders (requiring a 66 2/3 percent vote) may each request one special redetermination.

Advances on the Credit Facility bear interest, at the Company’s option, based on (i) the prime rate of JPMorgan Chase Bank (“JPM Prime Rate”) (3.25 percent at September 30, 2013) or (ii) a Eurodollar rate (substantially equal to the LIBOR). At September 30, 2013, the interest rates of Eurodollar rate advances and JPM Prime Rate advances varied, with interest margins ranging from 150 to 250 basis points and 50 to 150 basis points per annum, respectively, depending on the debt balance outstanding on the Credit Facility. At September 30, 2013, the Company paid commitment fees on the unused portion of the available commitments ranging from 37.5 to 50 basis points per annum.

The Credit Facility also includes a same-day advance facility under which the Company may borrow funds from the administrative agent. Same-day advances cannot exceed $25 million, and the maturity dates cannot exceed fourteen days. The interest rate on the same-day advance facility is the JPM Prime Rate plus the applicable interest margin.

The Company's obligations under the Credit Facility are secured by a first lien on substantially all of its oil and natural gas properties. In addition, all of the Company's subsidiaries are guarantors and have had their equity pledged to secure borrowings under the Credit Facility.

The Credit Facility contains various restrictive covenants and compliance requirements which include:

- maintenance of certain financial ratios, including (i) maintenance of a quarterly ratio of total debt to last twelve months of consolidated earnings before interest expense, income taxes, depletion, depreciation, and amortization, exploration expense and other noncash income and expenses to be no greater than 4.0 to 1.0, and (ii) maintenance of a ratio of current assets to current liabilities, excluding noncash assets and liabilities related

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to financial derivatives and asset retirement obligations and including the unfunded amounts under the Credit Facility, to be not less than 1.0 to 1.0;

- limits on the incurrence of additional indebtedness and certain types of liens;

- restrictions as to mergers, combinations and dispositions of assets; and

- limitations on the payment of cash dividends.

Senior notes. Interest on the Company's senior notes is paid in arrears semi-annually. The senior notes are fully and unconditionally guaranteed on a senior unsecured basis by all subsidiaries of the Company, subject to customary release provisions as described in Note P.

On June 3, 2013, the Company received tenders and consents from the holders of approximately $225.6 million in aggregate principal amount, or approximately 75.2 percent, of its outstanding 8.625% senior notes due 2017 (the "8.625% Notes") in connection with a cash tender offer for any and all of the 8.625% Notes at a price of 106.922 percent of the unpaid principal amount.

On June 21, 2013, the Company redeemed the remaining outstanding 8.625% Notes not purchased in the tender offer at a redemption price of 106.516 percent of the unpaid principal amount plus accrued and unpaid interest through June 20, 2013.

The Company recorded a loss on extinguishment of debt related to the tender offer and redemption of its 8.625% Notes of approximately $28.6 million for the nine months ended September 30, 2013. This amount includes approximately $20.4 million associated with the premium paid for the tender offer and redemption of the notes, approximately $5.5 million of unamortized deferred loan costs and approximately $2.7 million of unamortized discount.

On June 4, 2013, the Company completed the issuance of an additional $850 million in principal amount of its 5.5% senior notes due 2023 (the “Offering”) at 103.75 percent of par (resulting in a 4.884% yield) for net proceeds of approximately $867.8 million. The Company used a portion of the net proceeds from the Offering to fund the tender offer and redemption of the 8.625% Notes and to pay down amounts outstanding on the Credit Facility.

At September 30, 2013, the Company was in compliance with the covenants under its debt instruments.

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Future benefit to interest expense from original issue premium at September 30, 2013 was as follows:

(in thousands)		
Remaining 2013	$	629
2014		2,602
2015		2,747
2016		2,900
2017		3,062
2018		3,233
Thereafter		15,877
Total	$	31,050

Principal maturities of debt. Principal maturities of long-term debt outstanding at September 30, 2013 were as follows:

(in thousands)		
Remaining 2013	$	-
2014		-
2015		-
2016		207,600
2017		-
2018		-
Thereafter		3,350,000
Total	$	3,557,600

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Interest expense. The following amounts have been incurred and charged to interest expense for the three and nine months ended September 30, 2013 and 2012:

(in thousands)	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Cash payments for interest	$ 43,868	$ 48,203	$ 145,980	$ 115,731
Amortization of original issue discount (premium)	(620)	117	(619)	342
Amortization of deferred loan origination costs	3,311	3,114	9,844	8,724
Net changes in accruals	9,436	(97)	6,975	4,276
Total interest expense	$ 55,995	$ 51,337	$ 162,180	$ 129,073

Note J. ***Commitments and contingencies***

Severance agreements. The Company has entered into severance and change in control agreements with all of its officers. The current annual salaries for the Company's officers covered under such agreements total approximately $5.6 million.

Indemnifications. The Company has agreed to indemnify its directors and officers with respect to claims and damages arising from certain acts or omissions taken in such capacity.

Legal actions. The Company is a party to proceedings and claims incidental to its business. While many of these matters involve inherent uncertainty, the Company believes that the amount of the liability, if any, ultimately incurred with respect to any such proceedings or claims will not have a material adverse effect on the Company's consolidated financial position as a whole or on its liquidity, capital resources or future results of operations. The Company will continue to evaluate proceedings and claims involving the Company on a regular basis and will establish and adjust any reserves as appropriate to reflect its assessment of the then current status of the matters.

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Contractual drilling commitments. The Company periodically enters into contractual arrangements under which the Company is committed to expend funds to drill wells in the future, including agreements to secure drilling rig services, which require the Company to make future minimum payments to the rig operators. The Company records drilling commitments in the periods in which well capital is incurred or rig services are provided. The following table summarizes the Company's future drilling commitments at September 30, 2013:

	Payments Due By Period				
(in thousands)	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Contractual drilling commitments	$ 8,084	$ 8,084	$ -	$ -	$ -

Operating leases. The Company leases vehicles, equipment and office facilities under non-cancellable operating leases. Lease payments associated with these operating leases for the three months ended September 30, 2013 and 2012 were approximately $1.5 million and $1.3 million, respectively, and approximately $4.2 million and $3.6 million for the nine months ended September 30, 2013 and 2012, respectively.

Future minimum lease commitments under non-cancellable operating leases at September 30, 2013 were as follows:

(in thousands)	
Remaining 2013	$ 1,508
2014	5,372
2015	4,146
2016	2,778

2017		750
2018		441
Thereafter		1,247
Total	$	16,242

Note K. ***Income taxes***

The Company uses an asset and liability approach for financial accounting and reporting for income taxes. The Company's objectives of accounting for income taxes are to recognize (i) the amount of taxes payable or refundable for the current year and (ii) deferred tax liabilities and assets for the future tax consequences of events that have been recognized in its financial statements or tax returns. The Company and its subsidiaries file a federal income tax return on a consolidated basis. The tax returns and the amount of taxable income or loss are subject to examination by federal and state taxing authorities. At September 30, 2013, the Company had current income taxes receivable of approximately $3.8 million. At September 30, 2013 and December 31, 2012, the Company had current income taxes payable of approximately $0.4 million and $2.1 million, respectively.

The Company continually assesses both positive and negative evidence to determine whether it is more likely than not that deferred tax assets can be realized prior to their expiration. Management monitors company-specific, oil and natural gas

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industry and worldwide economic factors and assesses the likelihood that the Company's net operating loss carryforwards, if any, and other deferred tax attributes in the United States, state, and local tax jurisdictions will be utilized prior to their expiration. At September 30, 2013 and December 31, 2012, the Company had no valuation allowances related to its deferred tax assets.

At September 30, 2013, the Company did not have any significant uncertain tax positions requiring recognition in the financial statements. The tax years 2009 through 2012 remain subject to examination by the major tax jurisdictions.

Income tax provision. The Company's income tax provision (benefit) and amounts separately allocated were attributable to the following items for the three and nine months ended September 30, 2013 and 2012:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	**2013**	**2012**	**2013**	**2012**
Income (loss) from continuing operations	$ 21,695	$ (995)	$ 86,023	$ 204,327
Income from discontinued operations	-	5,150	7,518	16,508
Changes in stockholders' equity:				
Excess tax benefits related to stock-based compensation	(5,081)	(8,129)	(9,244)	(18,522)
	$ 16,614	$ (3,974)	$ 84,297	$ 202,313

The Company's income tax provision (benefit) attributable to income from continuing operations consisted of the following for the three and nine months ended September 30, 2013 and 2012:

Three Months Ended September 30,	Nine Months Ended September 30,

(in thousands)	2013	2012	2013	2012
Current:				
U.S. federal	$ (3,661)	$ (3,259)	$ 8,427	$ (1,155)
U.S. state and local	(106)	555	1,788	2,375
Total current income tax provision (benefit)	(3,767)	(2,704)	10,215	1,220
Deferred:				
U.S. federal	23,652	2,240	67,529	178,766
U.S. state and local	1,810	(531)	8,279	24,341
Total deferred income tax provision	25,462	1,709	75,808	203,107
Total income tax provision (benefit) attributable to income from continuing operations	$ 21,695	$ (995)	$ 86,023	$ 204,327

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The reconciliation between the income tax expense (benefit) computed by multiplying pretax income (loss) from continuing operations by the United States federal statutory rate and the reported amounts of income tax expense (benefit) from continuing operations is as follows:

(in thousands)	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Income (loss) at U.S. federal statutory rate	$ 18,241	$ (1,458)	$ 76,705	$ 185,979
State income taxes (net of federal tax effect)	1,726	(159)	7,161	17,245
Revision of previous tax estimates	1,273	219	1,273	219
Statutory depletion	58	(91)	(21)	(207)
Nondeductible expense & other	397	494	905	1,091
Income tax expense (benefit)	$ 21,695	$ (995)	$ 86,023	$ 204,327
Effective tax rate	41.6%	23.9%	39.3%	38.5%

The Company's income tax provision attributable to income from discontinued operations consisted of the following for the three and nine months ended September 30, 2013 and 2012:

(in thousands)	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Current:				
U.S. federal	$ -	$ 4,589	$ 144	$ 14,729
U.S. state and local	-	25	25	82
Total current income tax provision	-	4,614	169	14,811
Deferred:				
U.S. federal	-	(107)	6,397	(366)

U.S. state and local		-		643		952		2,063
Total deferred income tax provision		-		536		7,349		1,697
Total income tax provision attributable to income from discontinued operations	$	-	$	5,150	$	7,518	$	16,508

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Note L. ***Related party transactions***

The following tables summarize charges incurred with and payments made to related parties and reported in the Company's consolidated statements of operations, as well as outstanding payables included in the consolidated balance sheets for the periods presented:

(in thousands)	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Royalties paid to a partnership in which a director has an ownership interest (a)	$ 2,010	$ 525	$ 4,694	$ 1,820
Royalties paid to a director and certain officers of the Company (b)	$ 12	$ -	$ 33	$ -
Amounts paid under consulting agreement with Steven L. Beal (c)	$ 745	$ 60	$ 865	$ 180

(in thousands)	September 30, 2013	December 31, 2012
Amounts included in accounts payable - related parties:		
Royalty interests of a director of the Company (a)	$ -	$ 185

(a) Royalties paid on certain properties to a partnership of which a director is the general partner and owns a 3.5 percent partnership interest.

(b) Payments made to a director and certain officers who directly own overriding royalty interests in properties owned by the Company.

(c) On June 30, 2009, Steven L. Beal, the Company's then-president and chief operating officer, retired from such positions. On June 9, 2009, the Company entered into a consulting agreement (the "Consulting Agreement") with Mr. Beal, under which Mr. Beal began serving as a consultant to the Company on July 1, 2009. During the term of the consulting relationship, Mr. Beal received a consulting fee of $20,000 per month and a monthly reimbursement for his medical and dental coverage costs. In August 2013, the Company and Mr. Beal mutually terminated the Consulting Agreement in exchange for the payment to Mr. Beal of $720,000, which termination and payment were approved by the disinterested members of the Company's Board of Directors.

In June 2013, in connection with the tender offer for the 8.625% Notes, certain directors and officers received an aggregate amount of approximately $1.3 million for the 8.625% Notes they owned.

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Note M. ***Discontinued operations***

In December 2012, the Company closed the sale of certain of its non-core assets for cash consideration of approximately $503.1 million, which resulted in a pre-tax gain of approximately $0.9 million. As a result of post-closing adjustments during the nine months ended September 30, 2013, the Company made adjustments to its pre-tax gain of approximately $19.6 million. The Company reflected the results of operations of this divestiture as discontinued operations, rather than as a component of continuing operations. The following table represents the components of the Company's discontinued operations for the three and nine months ended September 30, 2013 and 2012:

(in thousands)	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Operating revenues:				
Oil sales	$ -	$ 26,616	$ -	$ 82,518
Natural gas sales	-	5,588	-	13,342
Total operating revenues	-	32,204	-	95,860
Operating costs and expenses:				
Oil and natural gas production	-	8,702	-	24,864
Depreciation, depletion and amortization (a)	-	9,476	-	26,265
Accretion of discount on asset retirement obligations (a)	-	336	-	629
General and administrative (b)	-	(619)	-	(1,766)
Total operating costs and expenses	-	17,895	-	49,992
Income from operations	-	14,309	-	45,868
Other income (expense):				
Gain on disposition of assets, net (a)	-	-	19,599	-
Income from discontinued operations before income taxes	-	14,309	19,599	45,868
Income tax expense:				
Current	-	(4,614)	(169)	(14,811)
Deferred (a)	-	(536)	(7,349)	(1,697)

Income from discontinued operations, net of tax	$	-	$	9,159	$	12,081	$	29,360

(a) Represents the significant non-cash components of discontinued operations.

(b) Represents the fees received from third-parties for operating oil and natural gas properties that were sold. The Company reflects these fees as a reduction of general and administrative expenses.

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Note N. ***Net income per share***

The Company uses the two-class method of calculating net income (loss) per share because certain of the Company's unvested share-based awards qualify as participating securities. Participating securities participate in income proportionate to the weighted average number of outstanding common shares, but are not assumed to participate in the Company's net losses because they are not contractually obligated to do so. Accordingly, allocations of earnings to participating securities are included in the Company's calculations of basic and diluted earnings per share from continuing operations, discontinued operations and net income (loss) attributable to common stockholders.

The following tables reconcile the Company's net income (loss) from continuing operations, income from discontinued operations and net income (loss) attributable to common stockholders to the basic and diluted earnings used to determine the Company's net income per share amounts for the three and nine months ended September 30, 2013 and 2012, respectively, under the two-class method:

	Three Months Ended September 30, 2013			Nine Months Ended September 30, 2013		
(in thousands, except per share amounts)	**Continuing Operations**	**Discontinued Operations**	**Total**	**Continuing Operations**	**Discontinued Operations**	**Total**
Income as reported	$ 30,421	$ -	$ 30,421	$ 133,133	$ 12,081	$ 145,214
Participating basic earnings	(357)	-	(357)	(1,421)	(129)	(1,550)
Basic income attributable to common stockholders	30,064	-	30,064	131,712	11,952	143,664
Reallocation of participating earnings	-	-	-	2	-	2
Diluted income attributable to common						

stockholders	$	30,064	$	-	$	30,064	$	131,714	$	11,952	$	143,666
Income per common share:												
Basic	$	0.29	$	-	$	0.29	$	1.27	$	0.12	$	1.39
Diluted	$	0.29	$	-	$	0.29	$	1.27	$	0.11	$	1.38

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	Three Months Ended September 30, 2012			Nine Months Ended September 30, 2012		
(in thousands, except per share amounts)	**Continuing Operations**	**Discontinued Operations**	**Total**	**Continuing Operations**	**Discontinued Operations**	**Total**
Income (loss) as reported	$ (3,171)	$ 9,159	$ 5,988	$ 327,042	$ 29,360	$ 356,402
Participating basic earnings	-	-	-	-	-	-
Basic income (loss) attributable to common stockholders	(3,171)	9,159	5,988	327,042	29,360	356,402
Reallocation of participating earnings	-	-	-	-	-	-
Diluted income (loss) attributable to common stockholders	$ (3,171)	$ 9,159	$ 5,988	$ 327,042	$ 29,360	$ 356,402
Income (loss) per common share:						
Basic	$ (0.03)	$ 0.09	$ 0.06	$ 3.17	$ 0.29	$ 3.46
Diluted	$ (0.03)	$ 0.09	$ 0.06	$ 3.15	$ 0.28	$ 3.43

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The following table is a reconciliation of the basic weighted average common shares outstanding to diluted weighted average common shares outstanding for the three and nine months ended September 30, 2013 and 2012:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	**2013**	**2012**	**2013**	**2012**
Weighted average common shares outstanding:				
Basic	103,801	103,292	103,709	103,088
Dilutive common stock options	157	323	173	399
Dilutive restricted stock	-	425	-	411
Dilutive performance units	-	-	-	-
Diluted	103,958	104,040	103,882	103,898

The following table is a summary of the common stock options, restricted stock and performance units which were not included in the computation of diluted net income per share, as inclusion would be antidilutive:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	**2013**	**2012**	**2013**	**2012**
Number of antidilutive common shares:				
Antidilutive common stock options	-	-	-	-
Antidilutive restricted stock	2	31	7	126
Antidilutive performance units	111	-	111	-

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Note O. ***Other current liabilities***

The following table provides the components of the Company's other current liabilities at September 30, 2013 and December 31, 2012:

(in thousands)	**September 30, 2013**	**December 31, 2012**
Other current liabilities:		
Accrued production costs	$ 53,642	$ 52,825
Payroll related matters	21,360	16,365
Accrued interest	79,460	64,304
Settlements due on derivatives not designated as hedges	17,304	-
Acquisition and divestiture settlements	-	18,100
Income taxes payable	425	2,141
Asset retirement obligations	2,674	3,308
Other	3,862	3,297
Other current liabilities	$ 178,727	$ 160,340

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Note P. ***Subsidiary guarantors***

As of September 30, 2013, all of the Company’s wholly-owned subsidiaries have fully and unconditionally guaranteed the Company’s senior notes. The indentures governing the Company’s senior notes provide that the guarantees of its subsidiary guarantors will be released in certain customary circumstances, including (i) in connection with any sale, exchange or other disposition, whether by merger, consolidation or otherwise, of the capital stock of that guarantor to a person that is not the Company or a restricted subsidiary of the Company, such that, after giving effect to such transaction, such guarantor would no longer constitute a subsidiary of the Company, (ii) in connection with any sale, exchange or other disposition (other than a lease) of all or substantially all of the assets of that guarantor to a person that is not the Company or a restricted subsidiary of the Company, (iii) upon the merger of a guarantor into the Company or any other guarantor or the liquidation or dissolution of a guarantor, (iv) if the Company designates any restricted subsidiary that is a guarantor to be an unrestricted subsidiary in accordance with the indenture, (v) upon legal defeasance or satisfaction and discharge of the indenture and (vi) upon written notice of such release or discharge by the Company to the trustee following the release or discharge of all guarantees by such guarantor of any indebtedness that resulted in the creation of such guarantee, except a discharge or release by or as a result of payment under such guarantee.

See Note I for a summary of the Company’s senior notes. In accordance with practices accepted by the U.S. Securities and Exchange Commission, the Company has prepared condensed consolidating financial statements in order to quantify the assets, results of operations and cash flows of such subsidiaries as subsidiary guarantors.

In 2012, one of the entities included in the Company’s consolidated financial statements was formed to effectuate a tax-free exchange of assets. This entity did not guarantee the Company’s senior notes and is referred to as a “Non-Guarantor Subsidiary” in the tables below.

The following condensed consolidating balance sheets at September 30, 2013 and December 31, 2012, condensed consolidating statements of operations for the three and nine months ended September 30, 2013 and 2012 and condensed consolidating statements of cash flows for the nine months ended September 30, 2013 and 2012, present financial information for Concho Resources Inc. as the Parent on a stand-alone basis (carrying any investments in subsidiaries under the equity method), financial information for the subsidiary guarantors on a stand-alone basis and the consolidation and elimination entries necessary to arrive at the information for the Company on a consolidated basis. All current and deferred income taxes are recorded on Concho Resources Inc., as the subsidiaries are flow-through entities for income tax purposes. The subsidiary guarantors are not restricted from making distributions to the Company.

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Condensed Consolidating Balance Sheet
September 30, 2013

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
ASSETS				
Accounts receivable - related parties	$ 6,158,999	$ 1,279,039	$ (7,438,038)	$ -
Other current assets	36,298	571,414	-	607,712
Oil and natural gas properties, net	-	8,676,205	-	8,676,205
Property and equipment, net	-	111,705	-	111,705
Investment in subsidiaries	3,735,429	-	(3,735,429)	-
Other long-term assets	76,376	58,703	-	135,079
Total assets	$ 10,007,102	$ 10,697,066	$ (11,173,467)	$ 9,530,701
LIABILITIES AND EQUITY				
Accounts payable - related parties	$ 1,279,039	$ 6,158,999	$ (7,438,038)	$ -
Other current liabilities	168,402	705,882	-	874,284
Other long-term liabilities	1,326,298	96,756	-	1,423,054
Long-term debt	3,588,650	-	-	3,588,650
Equity	3,644,713	3,735,429	(3,735,429)	3,644,713
Total liabilities and equity	$ 10,007,102	$ 10,697,066	$ (11,173,467)	$ 9,530,701

Condensed Consolidating Balance Sheet
December 31, 2012

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
ASSETS				
Accounts receivable - related parties	$ 5,839,995	$ 2,416,697	$ (8,256,692)	$ -
Other current assets	46,737	412,145	-	458,882
Oil and natural gas properties, net	-	7,890,283	-	7,890,283
Property and equipment, net	-	103,141	-	103,141
Investment in subsidiaries	3,146,918	-	(3,146,918)	-
Other long-term assets	80,378	56,753	-	137,131
Total assets	$ 9,114,028	$ 10,879,019	$ (11,403,610)	$ 8,589,437
LIABILITIES AND EQUITY				
Accounts payable - related parties	$ 1,271,563	$ 6,985,314	$ (8,256,692)	$ 185
Other current liabilities	76,496	663,405	-	739,901
Other long-term liabilities	1,198,670	83,382	-	1,282,052
Long-term debt	3,101,103	-	-	3,101,103
Equity	3,466,196	3,146,918	(3,146,918)	3,466,196
Total liabilities and equity	$ 9,114,028	$ 10,879,019	$ (11,403,610)	$ 8,589,437

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Condensed Consolidating Statement of Operations
Three Months Ended September 30, 2013

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Total operating revenues	$ -	$ 652,920	$ -	$ 652,920
Total operating costs and expenses	(169,935)	(372,933)	-	(542,868)
Income (loss) from continuing operations	(169,935)	279,987	-	110,052
Interest expense	(55,995)	-	-	(55,995)
Other, net	278,046	(1,996)	(277,991)	(1,941)
Income from continuing operations before income taxes	52,116	277,991	(277,991)	52,116
Income tax expense	(21,695)	-	-	(21,695)
Net income	$ 30,421	$ 277,991	$ (277,991)	$ 30,421

Condensed Consolidating Statement of Operations
Three Months Ended September 30, 2012

(in thousands)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantor	Consolidating Entries	Total
Total operating revenues	$ -	$ 458,001	$ 7,342	$ -	$ 465,343
	(135,637)	(273,701)	(5,720)	-	(415,058)

Total operating costs and expenses					
Income (loss) from continuing operations	(135,637)	184,300	1,622	-	50,285
Interest expense	(51,337)	-	-	-	(51,337)
Other, net	197,117	2,309	(6,043)	(196,497)	(3,114)
Income (loss) from continuing operations before income taxes	10,143	186,609	(4,421)	(196,497)	(4,166)
Income tax benefit	995	-	-	-	995
Income (loss) from continuing operations	11,138	186,609	(4,421)	(196,497)	(3,171)
Income (loss) from discontinued operations, net of tax	(5,150)	14,309	-	-	9,159
Net income (loss)	$ 5,988	$ 200,918	$ (4,421)	$ (196,497)	$ 5,988

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Condensed Consolidating Statement of Operations
Nine Months Ended September 30, 2013

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Total operating revenues	$ -	$ 1,687,833	$ -	$ 1,687,833
Total operating costs and expenses	(159,017)	(1,117,058)	-	(1,276,075)
Income (loss) from continuing operations	(159,017)	570,775	-	411,758
Interest expense	(162,180)	-	-	(162,180)
Loss on extinguishment of debt	(28,616)	-	-	(28,616)
Other, net	588,568	(1,863)	(588,511)	(1,806)
Income from continuing operations before income taxes	238,755	568,912	(588,511)	219,156
Income tax expense	(86,023)	-	-	(86,023)
Income from continuing operations	152,732	568,912	(588,511)	133,133
Income (loss) from discontinued operations, net of tax	(7,518)	19,599	-	12,081
Net income	$ 145,214	$ 588,511	$ (588,511)	$ 145,214

Condensed Consolidating Statement of Operations
Nine Months Ended September 30, 2012

(in thousands)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantor	Consolidating Entries	Total
Total operating revenues	$ -	$ 1,334,946	$ 7,342	$ -	$ 1,342,288

Total operating costs and expenses	108,776	(779,985)	(5,720)	-	(676,929)
Income from continuing operations	108,776	554,961	1,622	-	665,359
Interest expense	(129,073)	-	-	-	(129,073)
Other, net	597,534	522	(6,043)	(596,930)	(4,917)
Income (loss) from continuing operations before income taxes	577,237	555,483	(4,421)	(596,930)	531,369
Income tax expense	(204,327)	-	-	-	(204,327)
Income (loss) from continuing operations	372,910	555,483	(4,421)	(596,930)	327,042
Income (loss) from discontinued operations, net of tax	(16,508)	45,868	-	-	29,360
Net income (loss)	$ 356,402	$ 601,351	$ (4,421)	$ (596,930)	$ 356,402

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Condensed Consolidating Statement of Cash Flows
Nine Months Ended September 30, 2013

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Net cash flows provided by (used in) operating activities	$ (441,741)	$ 1,386,385	$ -	$ 944,644
Net cash flows used in investing activities	(37,684)	(1,434,412)	-	(1,472,096)
Net cash flows provided by financing activities	479,425	45,169	-	524,594
Net decrease in cash and cash equivalents	-	(2,858)	-	(2,858)
Cash and cash equivalents at beginning of period	-	2,880	-	2,880
Cash and cash equivalents at end of period	$ -	$ 22	$ -	$ 22

Condensed Consolidating Statement of Cash Flows
Nine Months Ended September 30, 2012

(in thousands)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantor	Consolidating Entries	Total
Net cash flows provided by (used in) operating activities	$ (1,512,952)	$ 2,355,751	$ 2,837	$ -	$ 845,636
Net cash flows used in investing activities	(7,485)	(1,816,184)	(543,738)	-	(2,367,407)

Net cash flows provided by (used in) financing activities	1,520,437	(539,618)	540,901	-	1,521,720
Net decrease in cash and cash equivalents	-	(51)	-	-	(51)
Cash and cash equivalents at beginning of period	-	342	-	-	342
Cash and cash equivalents at end of period	$ -	$ 291	$ -	$ -	$ 291

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Note Q. ***Subsequent events***

New commodity derivative contracts. After September 30, 2013, the Company entered into the following oil price swaps to hedge additional amounts of the Company's estimated future production:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Swaps: (a)					
2013:					
Volume (Bbl)				150,000	150,000
Price per Bbl				$ 102.55	$ 102.55
2014:					
Volume (Bbl)	153,000	152,000	129,000	91,000	525,000
Price per Bbl	$ 97.78	$ 97.78	$ 97.71	$ 97.53	$ 97.72
2015:					
Volume (Bbl)	94,000	100,000	85,000	96,000	375,000
Price per Bbl	$ 89.84	$ 89.84	$ 89.83	$ 89.84	$ 89.84

(a) The index prices for the oil price swaps are based on the NYMEX – West Texas Intermediate ("WTI") monthly average futures price.

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Note R. ***Supplementary information***

Capitalized costs

(in thousands)	September 30, 2013	December 31, 2012
Oil and natural gas properties:		
Proved	$ 9,732,454	$ 8,402,154
Unproved	1,119,792	1,053,445
Less: accumulated depletion	(2,176,041)	(1,565,316)
Net capitalized costs for oil and natural gas properties	$ 8,676,205	$ 7,890,283

Costs incurred for oil and natural gas producing activities (a)

(in thousands)	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Property acquisition costs:				
Proved	$ -	$ 690,158	$ 2,376	$ 855,773
Unproved	13,991	349,903	58,832	411,110
Exploration	229,082	223,569	779,026	567,065
Development	197,696	187,759	593,006	574,541
Total costs incurred for oil and natural gas properties	$ 440,769	$ 1,451,389	$ 1,433,240	$ 2,408,489

(a) The costs incurred for oil and natural gas producing activities includes the following amounts of asset retirement obligations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	**2013**	**2012**	**2013**	**2012**
Exploration costs	$ 535	$ 1,185	$ 2,089	$ 2,452
Development costs	1,801	5,019	9,163	8,302
Total asset retirement obligations	$ 2,336	$ 6,204	$ 11,252	$ 10,754

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

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with our historical consolidated financial statements and notes. As a result of the acquisitions and divesture discussed below, many comparisons between periods may be difficult or impossible.

In December 2012, we closed the sale of certain of our non-core assets for cash consideration of approximately $503.1 million, which resulted in a pre-tax gain of approximately $0.9 million (included in discontinued operations). For the nine months ended September 30, 2012, these assets produced an average of 5,044 Boe per day.

In July 2012, we acquired certain producing and non-producing assets from Three Rivers Operating Company (the "Three Rivers Acquisition") for cash consideration of approximately $1.0 billion. The Three Rivers Acquisition was primarily funded with borrowings under our credit facility. The results of operations prior to July 2012 do not include results from the Three Rivers Acquisition.

In February 2012, we acquired certain producing and non-producing assets from Petroleum Development Corporation (the "PDC Acquisition") for cash consideration of approximately $189.2 million. The PDC Acquisition was primarily funded with borrowings under our credit facility. The results of operations prior to March 2012 do not include results from the PDC Acquisition.

Certain statements in our discussion below are forward-looking statements. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause actual results to differ materially from those implied or expressed by the forward-looking statements. Please see "Cautionary Statement Regarding Forward-Looking Statements."

Overview

We are an independent oil and natural gas company engaged in the acquisition, development and exploration of producing oil and natural gas properties. Our core operations are primarily focused in the Permian Basin of Southeast New Mexico and West Texas. We refer to our three core operating areas as the (i) New Mexico Shelf, where we primarily target the Yeso formation, (ii) Delaware Basin, where we primarily target the Bone Spring formation (which includes the Avalon Shale and the Bone Spring sands) and the Wolfcamp shale, and (iii) Texas Permian, where we primarily target the Wolfberry, a term applied to the combined Wolfcamp and Spraberry horizons. Oil comprised 61.2

percent of our 447.2 MMBoe of estimated proved reserves at December 31, 2012 and 62.2 percent of our 24.7 MMBoe of production for the nine months ended September 30, 2013. We seek to operate the wells in which we own an interest, and we operated wells that accounted for 91.3 percent of our proved developed producing PV-10 and 81.6 percent of our approximately 5,800 gross wells at December 31, 2012. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and stimulation methods used.

Financial and Operating Performance

Our financial and operating performance for the nine months ended September 30, 2013, as compared to the nine months ended September 30, 2012, included the following highlights:

• Net income was $145.2 million ($1.38 per diluted share) for the first nine months of 2013, as compared to net income of $356.4 million ($3.43 per diluted share) during the nine months ended September 30, 2012. The decrease in net income was primarily due to:

§ $157.3 million loss on derivatives not designated as hedges for the nine months ended September 30, 2013, as compared to a $109.5 million gain on derivatives not designated as hedges during the nine months ended September 30, 2012, primarily related to commodity future price curves at the respective measurement periods;

§ $149.1 million increase in depreciation, depletion and amortization (“DD&A”) expense from continuing operations, primarily due to increased continuing operations production from (i) costs incurred associated with new wells that were successfully drilled and completed in the fourth quarter of 2012 and the first nine months of 2013 and (ii) our acquisitions in 2012;

§ $76.7 million increase in oil and natural gas production costs from continuing operations due in part to increased production related to our wells successfully drilled and completed in 2012 and 2013 and our acquisitions in 2012;

§ $65.4 million non-cash impairment charge in 2013 due primarily to downward adjustments to our economically recoverable proved reserves due to (i) reduced well performance and (ii) decreases in estimated realized natural gas prices, primarily on non-core natural gas properties in our New Mexico Shelf area;

§ $29.1 million increase in general and administrative expense due to (a) including an adjustment to our bonus accrual for services related to 2012 of approximately $5.9 million ($0.24 per Boe) recorded in 2013 and (b) an increase in the number of employees and related personnel expenses to handle our increased activities, both from (i) increased drilling and exploration activities and (ii) our acquisitions in 2012;

§ $33.1 million increase in interest expense due to a 24 percent increase in the weighted average debt balance outstanding between the periods, primarily related to our acquisitions in 2012 and the timing of our capital expenditures;

§ $28.6 million loss on extinguishment of debt in 2013 related to the tender offer and redemption of our 8.625% senior notes; and

§ $19.6 million pre-tax gain from discontinued operations in 2013 related to the post-closing adjustments to the divestiture of certain non-core assets in the fourth quarter of 2012 compared to $45.9 million of income from operations before income taxes related to the same assets in 2012;

partially offset by:

§ $345.5 million increase in oil and natural gas revenues from continuing operations as a result of a 23 percent increase in production, coupled with a 3 percent increase in commodity price realizations per Boe (excluding the effects of derivative activities).

- Average daily sales volumes from continuing operations increased by 23 percent from 73,599 Boe per day during the first nine months of 2012 to 90,514 Boe per day during the first nine months of 2013. The increase was primarily comprised of our successful drilling efforts during 2012 and 2013, with the remaining increase due to approximately 7,200 Boe per day attributable to our acquisitions in 2012, offset in part by normal production declines and curtailed production in our New Mexico Shelf area, discussed later.

- Net cash provided by operating activities increased by approximately $99.0 million to $944.6 million for the first nine months of 2013, as compared to $845.6 million in the first nine months of 2012, primarily due to increased oil and natural gas revenues, partially offset by (i) increases in oil and natural gas production costs, general and administrative expense and interest expense and (ii) a larger negative variance in working capital changes, which adjust for the timing of receipts and payments of actual cash.

- Long-term debt increased by approximately $487.5 million during the first nine months of 2013, primarily as a result of the spending on drilling in excess of our operating cash flow.

- At September 30, 2013, availability under our credit facility was approximately $2.3 billion.

Commodity Prices

Our results of operations are heavily influenced by commodity prices. Commodity prices may fluctuate widely in response to (i) relatively minor changes in the supply of and demand for oil, (ii) natural gas and NGLs market uncertainty and (iii) a variety of additional factors that are beyond our control. Factors that may impact future commodity prices, including the price of oil, natural gas and NGLs include:

- economic stimulus initiatives in the United States;

- worldwide and continuing economic struggles in Eurozone nations' economies;

- political and economic developments in the Middle East;
- demand from Asian and European markets;
- the extent to which members of the Organization of Petroleum Exporting Countries and other oil exporting nations are able to continue to manage oil supply through export quotas;
- technological advances affecting energy consumption and energy supply;
- the effect of energy conservation efforts;
- the price and availability of alternative fuels;
- domestic and foreign governmental regulations and taxation;
- the proximity, capacity, cost and availability of pipelines and other transportation facilities;
- the quality of the oil we produce;
- the overall global demand for oil; and
- overall North American natural gas supply and demand fundamentals, including:

§ the United States economy impact,

§ weather conditions, and

§ liquefied natural gas deliveries to the United States.

Although we cannot predict the occurrence of events that may affect future commodity prices or the degree to which these prices will be affected, the prices for any commodity that we produce will generally approximate current market prices in the geographic region of the production. From time to time, we expect that we may economically hedge a portion of our commodity price risk to mitigate the impact of price volatility on our business. See Note H of the Condensed Notes to Consolidated Financial Statements included in "Item 1. Consolidated Financial Statements (Unaudited)" for additional information regarding our commodity derivative positions at September 30, 2013.

Oil and natural gas prices have been subject to significant fluctuations during the past several years. In general, average oil prices were relatively consistent in the nine months ended September 30, 2013 compared to the same period in 2012, while in the three months ended September 30, 2013 compared to the same period in 2012 there was a significant increase in average oil prices. Average natural gas prices in 2013 significantly improved relative to 2012. The following table sets forth the average New York Mercantile Exchange ("NYMEX") oil and natural gas prices for the three and nine months ended September 30, 2013 and 2012, as well as the high and low NYMEX prices for the same periods:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	**2012**	**2013**	**2012**
Average NYMEX prices:				
Oil (Bbl)	$ 105.94	$ 92.29	$ 98.21	$ 96.21
Natural gas (MMBtu)	$ 3.55	$ 2.89	$ 3.69	$ 2.59
High and Low NYMEX prices:				
Oil (Bbl):				
High	$ 110.53	$ 99.00	$ 110.53	$ 109.77
Low	$ 97.99	$ 83.75	$ 86.68	$ 77.69
Natural gas (MMBtu):				
High	$ 3.81	$ 3.32	$ 4.41	$ 3.32
Low	$ 3.23	$ 2.61	$ 3.11	$ 1.91

Further, the NYMEX oil and natural gas prices reached highs and lows of $104.10 and $94.61 per Bbl and $3.79 and $3.45 per MMBtu, respectively, during the period from September 30, 2013 to November 4, 2013. At November 4, 2013, the NYMEX oil and natural gas prices were $94.62 per Bbl and $3.45 per MMBtu, respectively.

Recent Events

2014 capital budget. In November 2013, we announced our 2014 capital budget of approximately $2.3 billion. Our 2014 capital program is expected to continue focusing on drilling in the Delaware Basin and Midland Basin. The 2014 capital budget, based on our current expectations of commodity prices and cost, will exceed our cash flow. We expect our cash flow and borrowings under our credit facility will be sufficient to fund our budgeted capital expenditure needs during 2014. However, our capital budget is largely discretionary, and if we experience sustained oil and natural gas prices significantly below the current levels or substantial increases in our costs, we may reduce our capital spending program to manage the level of capital outspend.

(in millions)		**2014 Capital Budget**
Drilling and completion costs:		
New Mexico Shelf	$	152
Delaware Basin		1,406
Texas Permian		459
Facilities and other capital in our core operating areas		188
Acquisition of leasehold acreage		75
Geological and geophysical data		20
Total	$	2,300

Revised 2013 capital budget. For 2013, we increased our capital budget by approximately $200 million to a total of approximately $1.8 billion, excluding the costs of acquisitions other than customary leasehold purchases of acreage. Based on current commodity prices and capital costs, we believe our 2013 expected capital expenditures, excluding the effects of acquisitions, will exceed our 2013 cash flow. We have funded, and expect to continue to fund, the shortfall, if any, with borrowings under our credit facility.

Three-year accelerated growth plan. We have adopted an accelerated drilling program for the next three years which we expect will double production by 2016. By accelerating activity across our assets, we believe that we can deliver average annual organic production growth over the next three years in excess of our historical annual average while increasing oil mix and reducing leverage ratios.

Tender offer and redemption of senior notes and senior notes issuance. On June 3, 2013, we received tenders and consents from the holders of approximately $225.6 million in aggregate principal amount, or approximately 75.2 percent, of our outstanding 8.625% senior notes due 2017 (the “8.625% Notes”) in connection with a cash tender offer for any and all of the 8.625% Notes at a price of 106.922 percent of the unpaid principal amount.

On June 21, 2013, we redeemed the remaining outstanding 8.625% Notes not purchased in the tender offer at a redemption price of 106.516 percent of the unpaid principal amount plus accrued and unpaid interest through June 20, 2013.

We recorded a loss on extinguishment of debt related to the redemption of the 8.625% Notes of approximately $28.6 million for the nine months ended September 30, 2013.

On June 4, 2013, we completed the issuance of an additional $850 million in principal amount of our 5.5% senior notes due 2023 (the “Offering”) at 103.75 percent of par (resulting in a 4.884% yield) for net proceeds of approximately $867.8 million. We used a portion of the net proceeds from the Offering to fund the tender offer and redemption of the 8.625% Notes and to pay down amounts outstanding on the credit facility. See Note I of the Condensed Notes to Consolidated Financial Statements included in “Item 1. Consolidated Financial Statements (Unaudited)” for additional information regarding our debt balance at September 30, 2013.

Derivatives. After September 30, 2013, we entered into the following additional oil price swaps to hedge additional amounts of our estimated future production:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Swaps: (a)					
2013:					
Volume (Bbl)				150,000	150,000
Price per Bbl				$ 102.55	$ 102.55
2014:					
Volume (Bbl)	153,000	152,000	129,000	91,000	525,000
Price per Bbl	$ 97.78	$ 97.78	$ 97.71	$ 97.53	$ 97.72
2015:					
Volume (Bbl)	94,000	100,000	85,000	96,000	375,000
Price per Bbl	$ 89.84	$ 89.84	$ 89.83	$ 89.84	$ 89.84

(a) The index prices for the oil price swaps are based on the NYMEX – West Texas Intermediate ("WTI") monthly average futures price.

Derivative Financial Instruments

Derivative financial instruments exposure. At September 30, 2013, the fair value of our financial derivatives was a net liability of $94.5 million. All of our counterparties to these financial derivatives are parties or affiliates of parties to our credit facility and have their outstanding debt commitments and derivative exposures collateralized pursuant to our credit facility. Under the terms of our financial derivative instruments and their collateralization under our credit facility, we do not have exposure to potential "margin calls" on our financial derivative instruments. We currently have no reason to believe that our counterparties to these commodity derivative contracts are not financially viable. Our credit facility does not allow us to offset amounts we may owe a lender against amounts we may be owed related to our financial instruments with such party or its affiliates.

Results of Operations

The following table sets forth summary information concerning our production and operating data from continuing operations for the three and nine months ended September 30, 2013 and 2012. The table below excludes production and operating data that we have classified as discontinued operations, which is more fully described in Note M of the Condensed Notes to Consolidated Financial Statements included in “Item 1. Consolidated Financial Statements (Unaudited).” The actual historical data in this table excludes results from (i) the Three Rivers Acquisition for periods prior to July 2012 and (ii) the PDC Acquisition for periods prior to March 2012. Because of normal production declines, increased or decreased drilling activities and the effects of acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	**2012**	**2013**	**2012**
Production and operating data from continuing operations:				
Net production volumes:				
Oil (MBbl)	5,417	4,312	15,376	12,141
Natural gas (MMcf)	19,593	17,740	56,006	48,151
Total (MBoe)	8,683	7,269	24,710	20,166
Average daily production volumes:				
Oil (Bbl)	58,880	46,870	56,322	44,310
Natural gas (Mcf)	212,967	192,826	205,150	175,734
Total (Boe)	94,375	79,008	90,514	73,599
Average prices:				
Oil, without derivatives (Bbl)	$ 102.10	$ 88.23	$ 91.89	$ 90.56
Oil, with derivatives (Bbl) (a)	$ 92.89	$ 91.91	$ 89.12	$ 89.87
Natural gas, without derivatives (Mcf)	$ 5.10	$ 4.79	$ 4.91	$ 5.04
Natural gas, with derivatives (Mcf) (a)	$ 5.33	$ 4.80	$ 5.00	$ 5.06
Total, without derivatives (Boe)	$ 75.20	$ 64.02	$ 68.31	$ 66.56
Total, with derivatives (Boe) (a)	$ 69.98	$ 66.24	$ 66.78	$ 66.19
Operating costs and expenses per Boe:				
Lease operating expenses and workover costs	$ 7.77	$ 6.87	$ 7.59	$ 7.00
Oil and natural gas taxes	$ 6.08	$ 5.22	$ 5.70	$ 5.48
Depreciation, depletion and amortization	$ 23.11	$ 20.38	$ 22.57	$ 20.26
General and administrative	$ 4.70	$ 4.88	$ 5.06	$ 4.76

(a)

Includes the effect of cash settlements received from (paid on) commodity derivatives not designated as hedges:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	**2013**	**2012**	**2013**	**2012**
Cash receipts from (payments on) derivatives not designated as hedges:				
Oil derivatives	$ (49,864)	$ 15,859	$ (42,528)	$ (8,374)
Natural gas derivatives	4,589	280	4,844	889
Total cash receipts from (payments on) derivatives	$ (45,275)	$ 16,139	$ (37,684)	$ (7,485)

The presentation of average prices with derivatives is a non-GAAP measure as a result of including the cash receipts from (payments on) commodity derivatives that are presented in our statements of cash flows. This presentation of average prices with derivatives is a means by which to reflect the actual cash performance of our commodity derivatives for the respective periods and presents oil and natural gas prices with derivatives in a manner consistent with the presentation generally used by the investment community.

The following table sets forth summary information from our discontinued operations concerning our production and operating data for the three and nine months ended September 30, 2012. The discontinued operations presentation is the result of reclassifying the results of operations from our December 2012 non-core assets divestiture, which is more fully described in Note M of the Condensed Notes to Consolidated Financial Statements included in "Item 1. Consolidated Financial Statements (Unaudited)."

	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012
Production and operating data from discontinued operations:		
Net production volumes:		
Oil (MBbl)	307	912
Natural gas (MMcf)	1,382	2,819
Total (MBoe)	537	1,382
Average daily production volumes:		
Oil (MBbl)	3,337	3,329
Natural gas (MMcf)	15,022	10,288
Total (MBoe)	5,840	5,044
Average prices:		
Oil, without derivatives (Bbl)	$ 86.70	$ 90.48
Oil, with derivatives (Bbl)	$ 86.70	$ 90.48
Natural gas, without derivatives (Mcf)	$ 4.04	$ 4.73
Natural gas, with derivatives (Mcf)	$ 4.04	$ 4.73
Total, without derivatives (Boe)	$ 59.97	$ 69.36
Total, with derivatives (Boe)	$ 59.97	$ 69.36
Operating costs and expenses per Boe:		
Lease operating expenses and workover costs	$ 10.84	$ 11.81
Oil and natural gas taxes	$ 5.37	$ 6.18
Depreciation, depletion and amortization	$ 17.65	$ 19.01
General and administrative (a)	$ (1.15)	$ (1.28)

(a) Represents the fees received from third-parties for operating oil and natural gas properties that were sold. We reflect these fees as a reduction of general and administrative expense.

Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 2012

Oil and natural gas revenues. Revenue from oil and natural gas operations was $652.9 million for the three months ended September 30, 2013, an increase of $187.6 million (40 percent) from $465.3 million for the three months ended September 30, 2012. This increase was primarily due to an increase in realized oil and natural gas prices and increased production due to successful drilling efforts during 2012 and 2013. Specific factors affecting oil and natural gas revenues include the following:

- total oil production was 5,417 MBbl for the three months ended September 30, 2013, an increase of 1,105 MBbl (26 percent) from 4,312 MBbl for the three months ended September 30, 2012;

- average realized oil price (excluding the effects of derivative activities) was $102.10 per Bbl during the three months ended September 30, 2013, an increase of 16 percent from $88.23 per Bbl during the three months ended September 30, 2012. For the three months ended September 30, 2013 and 2012, we realized approximately 96.4 percent and 95.6 percent, respectively, of the average NYMEX oil prices for the respective periods. The basis differential between the location of Midland, Texas and Cushing, Oklahoma (NYMEX pricing location) for our oil has a direct effect on our realized oil price. For the three months ended September 30, 2013 and 2012, the basis differential between WTI-Midland and WTI-Cushing was a price reduction of $0.29 per barrel and $1.74 per barrel, respectively, which is the primary reason for the higher realized oil price as compared as a percentage to the NYMEX price in 2013. The current outlook for the basis differential between WTI-Midland and WTI-Cushing for the remainder of 2013 is less than $1.00 per barrel;

- total natural gas production was 19,593 MMcf for the three months ended September 30, 2013, an increase of 1,853 MMcf (10 percent) from 17,740 MMcf for the three months ended September 30, 2012; and

- average realized natural gas price (excluding the effects of derivative activities) was $5.10 per Mcf during the three months ended September 30, 2013, an increase of 6 percent from $4.79 per Mcf during the three months ended September 30, 2012. For the three months ended September 30, 2013 and 2012, we realized approximately 143.7 percent and 165.7 percent, respectively, of the average NYMEX natural gas prices for the respective periods. Historically, approximately 55 to 80 percent of our total natural gas revenues were derived from the value of the natural gas liquids, with the remaining portion coming from the value of the dry natural gas residue. Because of our liquids-rich natural gas stream and the related value of the natural gas liquids being included in our natural gas revenues historically, our realized natural gas price (excluding the effects of derivatives) has reflected a price greater than the related NYMEX natural gas price. The deterioration of our realization percentage between comparable periods was primarily related to a combination of (i) a higher average NYMEX natural gas price between comparable periods ($3.56 per MMBtu in 2013 compared to $2.59 per MMBtu in 2012) and (ii) a lower price being received for the value of our natural gas liquids included within our natural gas revenue stream. We estimate that between the comparable periods, the value we received per gallon of natural gas liquids decreased approximately 9 percent, which is primarily the result of an increase in the supply of natural gas liquids from the significant industry drilling in liquid-prone areas.

Production expenses. The following table provides the components of our total oil and natural gas production costs for the three months ended September 30, 2013 and 2012:

	Three Months Ended September 30,			
	2013		2012	
(in thousands, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Lease operating expenses	$ 64,883	$ 7.47	$ 48,116	$ 6.62
Taxes:				
Ad valorem	5,610	0.65	3,812	0.52
Production	47,108	5.43	34,185	4.70
Workover costs	2,630	0.30	1,851	0.25
Total oil and natural gas production expenses	$ 120,231	$ 13.85	$ 87,964	$ 12.09

Among the cost components of production expenses, we have some control over lease operating expenses and workover costs on properties we operate, but production and ad valorem taxes are directly related to commodity prices.

Lease operating expenses were $64.9 million ($7.47 per Boe) for the three months ended September 30, 2013, which was an increase of $16.8 million (35 percent) from $48.1 million ($6.62 per Boe) for the three months ended September 30, 2012. The increase in lease operating expenses was primarily due to increased continuing operations production from our wells successfully drilled and completed in 2012 and 2013. The increase in lease operating expenses per Boe was primarily due to expansion of our production in areas with underdeveloped infrastructure and some minimal costs increases in services.

Ad valorem taxes have increased primarily as a result of increased valuations of our Texas properties and the increase in the number of wells primarily associated with our 2012 and 2013 drilling activity in the State of Texas, which includes wells in our Texas Permian and Delaware Basin areas.

Production taxes per unit of production were $5.43 per Boe during the three months ended September 30, 2013, an increase of 16 percent from $4.70 per Boe during the three months ended September 30, 2012. The increase was directly related to the increase in commodity prices. Over the same period, our per Boe prices (excluding the effects of derivatives) increased 17 percent.

Workover expenses were approximately $2.6 million and $1.9 million for the three months ended September 30, 2013 and 2012, respectively. The 2013 and 2012 expenses related primarily to routine workovers in the Texas Permian and New Mexico Shelf areas performed to restore production.

Exploration and abandonments expense. The following table provides a breakdown of our exploration and abandonments expense for the three months ended September 30, 2013 and 2012:

	Three Months Ended September 30,			
(in thousands)		**2013**		**2012**
Geological and geophysical	$	3,154	$	2,751
Exploratory dry hole costs		-		3,008
Leasehold abandonments		7,578		677
Other		260		522
Total exploration and abandonments	$	10,992	$	6,958

Our geological and geophysical expense primarily consists of the costs of acquiring and processing seismic data, geophysical data and core analysis, mostly related to our Delaware Basin and Texas Permian areas.

For the three months ended September 30, 2013, we recorded approximately $7.6 million of leasehold abandonments, which primarily related to non-core prospects in our Texas Permian area. For the three months ended September 30, 2012, we recorded approximately $0.7 million of leasehold abandonments, which primarily related to non-core prospects in our New Mexico Shelf area.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the three months ended September 30, 2013 and 2012:

	Three Months Ended September 30,			
	2013		2012	
(in thousands, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Depletion of proved oil and natural gas properties	$ 196,477	$ 22.63	$ 144,423	$ 19.87
Depreciation of other property and equipment	3,783	0.44	3,356	0.46
Amortization of intangible assets - operating rights	365	0.04	366	0.05
Total depletion, depreciation and amortization	$ 200,625	$ 23.11	$ 148,145	$ 20.38
Oil price used to estimate proved oil reserves at period end	$ 91.69		$ 91.48	
Natural gas price used to estimate proved reserved at period end	$ 3.60		$ 2.82	

Depletion of proved oil and natural gas properties was $196.5 million ($22.63 per Boe) for the three months ended September 30, 2013, an increase of $52.1 million (36 percent) from $144.4 million ($19.87 per Boe) for the three months ended September 30, 2012. The increase in depletion expense was primarily due to additional production associated with new wells that were successfully drilled and completed in the second half of 2012 and the first nine months of 2013 and higher depletion rates. The increase in depletion expense per Boe was primarily due to (i) drilling deeper, higher-cost wells in less proven areas and (ii) increasing production in our newer asset areas, such as the Delaware Basin, where we have a higher depletion rate than our legacy assets, such as the New Mexico Shelf, partially offset by the increase in the oil and natural gas prices between periods utilized to determine proved reserves.

More of our drilling capital is spent drilling higher-cost horizontal wells, much of which is in areas that have not had significant drilling activity or historically been developed vertically. Generally, when transitioning to a horizontal program, (i) well costs are higher as efficiencies from optimization of drilling and completion methodologies have yet to be realized and (ii) our ability to record proved reserves is limited under the rules associated with recognizing proved reserves, in part due to the limited amount of horizontal wells in the area and the lack of historical well production performance. As a result of these factors, the change in our production amongst our assets, discussed above, and our significant horizontal drilling activities in the Delaware Basin, we have seen increases in our overall depletion rate over the past year to $22.63 per Boe for the three months ended September 30, 2013 as compared to $22.28 per Boe for the three months ended June 30, 2013.

The increase in depreciation expense was primarily associated with our increase in depreciation of other property and equipment related to buildings and other items as a result of our increased number of employees.

The amortization of the intangible asset is a result of the value assigned to the operating rights that we acquired in an acquisition. The intangible asset is currently being amortized over an estimated life of 25 years.

General and administrative expenses. The following table provides components of our general and administrative expenses for the three months ended September 30, 2013 and 2012:

	Three Months Ended September 30,			
	2013		2012	
(in thousands, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
General and administrative expenses	$ 35,114	$ 4.04	$ 31,342	$ 4.31
Non-cash stock-based compensation	9,923	1.14	7,959	1.09
Less: Third -party operating fee reimbursements	(4,201)	(0.48)	(3,809)	(0.52)
Total general and administrative expenses	$ 40,836	$ 4.70	$ 35,492	$ 4.88

General and administrative expenses were approximately $40.8 million ($4.70 per Boe) for the three months ended September 30, 2013, an increase of $5.3 million (15 percent) from $35.5 million ($4.88 per Boe) for the three months ended September 30, 2012. The increase in general and administrative expenses and non-cash stock-based compensation was primarily due to an increase in the number of employees and related personnel expenses to handle our increased activities, both from (i) increased drilling and exploration activities and (ii) our acquisitions in 2012.

As the operator of certain oil and natural gas properties in which we own an interest, we earn overhead reimbursements during the drilling and production phases of the property. We earned reimbursements of $4.2 million and $3.8 million during the three months ended September 30, 2013 and 2012, respectively. This reimbursement is reflected as a reduction of general and administrative expenses in the consolidated statements of operations. The increase in third-party operating fee reimbursements was primarily due to increased reimbursements attributable to more wells operated as a result of continued drilling activity period over period.

Gain (loss) on derivatives not designated as hedges. The following table sets forth the gain (loss) on derivatives not designated as hedges for the three months ended September 30, 2013 and 2012:

Three Months Ended September 30,

(in thousands)	2013	2012
Gain (loss) on derivatives not designated as hedges:		
Oil derivatives	$ (169,049)	$ (135,401)
Natural gas derivatives	439	(14)
Total gain (loss) on derivatives not designated as hedges	$ (168,610)	$ (135,415)

The following table represents the Company's cash receipts from (payments on) derivatives not designated as hedges for the three months ended September 30, 2013 and 2012:

	Three Months Ended September 30,	
(in thousands)	2013	2012
Cash receipts from (payments on) derivatives not designated as hedges:		
Oil derivatives	$ (49,864)	$ 15,859
Natural gas derivatives	4,589	280
Total cash receipts from (payments on) derivatives not designated as hedges	$ (45,275)	$ 16,139

Our earnings are affected by the changes in value of our derivatives portfolio between periods and the related cash settlements of those derivatives, which can be volatile to our earnings. To the extent the future commodity price outlook declines between measurement periods, we will have mark-to-market gains, while to the extent future commodity price outlook increases between measurement periods, we will have mark-to-market losses.

Interest expense. The following table sets forth interest expense, weighted average interest rates and weighted average balance of debt for the three months ended September 30, 2013 and 2012:

	Three Months Ended September 30,	
(dollars in thousands)	**2013**	**2012**
Interest expense	$ 55,995	$ 51,337
Weighted average interest rate - credit facility	2.9%	2.4%
Weighted average interest rate - senior notes	5.9%	6.5%
Total weighted average interest rate	5.8%	5.2%
Weighted average balance of credit facility	$ 173,222	$ 1,125,549
Weighted average balance of senior notes	3,350,000	2,434,444
Total weighted average balance of debt	$ 3,523,222	$ 3,559,993

The increase in interest expense was primarily due to an overall increase in the weighted average interest rate due to the weighted average balance of our senior notes bearing a higher interest rate than our credit facility.

Income tax provisions. We recorded income tax expense of approximately $21.7 million for the three months ended September 30, 2013 and an income tax benefit of approximately $1.0 million for the three months ended September 30, 2012. The effective income tax rates for the three months ended September 30, 2013 and 2012 were 41.6 percent and 23.9 percent, respectively.

During the three months ended September 30, 2013 and 2012, we recorded expense of $1.3 million and $0.2 million, respectively, associated with revisions of estimates based on filing our 2012 and 2011 tax returns, respectively. During the three months ended September 30, 2013, this revision increased the effective rate by 2.4 percent from 39.2 percent.

Income from discontinued operations, net of tax. In December 2012, we closed the sale of certain of our non-core assets for cash consideration of approximately $503.1 million, which resulted in a pre-tax gain of approximately $0.9 million. We recognized income from discontinued operations of $9.2 million for the three months ended September 30, 2012.

The results of operations of these assets are reported as discontinued operations in the accompanying consolidated statements of operations, and are described in more detail in Note M of the Condensed Notes to Consolidated Financial Statements included in “Item 1. Consolidated Financial Statements (Unaudited).”

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012

Oil and natural gas revenues. Revenue from oil and natural gas operations was $1,687.8 million for the nine months ended September 30, 2013, an increase of $345.5 million (26 percent) from $1,342.3 million for the nine months ended September 30, 2012. This increase was primarily due to increased production due to (i) successful drilling efforts during 2012 and 2013, (ii) production from the PDC Acquisition which closed in February 2012, (iii) production from assets acquired in the Three Rivers Acquisition which closed in July 2012 and (iv) an increase in realized oil prices, partially offset by a decrease in realized natural gas prices and constraints related to infrastructure issues in the New Mexico Shelf area. Specific factors affecting oil and natural gas revenues include the following:

- total oil production was 15,376 MBbl for the nine months ended September 30, 2013, an increase of 3,235 MBbl (27 percent) from 12,141 MBbl for the nine months ended September 30, 2012. Approximately 800 MBbl of the increase was attributable to our acquisitions in 2012;

- average realized oil price (excluding the effects of derivative activities) was $91.89 per Bbl during the nine months ended September 30, 2013, an increase of 1 percent from $90.56 per Bbl during the nine months ended September 30, 2012. For the nine months ended September 30, 2013 and 2012, we realized approximately 93.6 percent and 94.1 percent, respectively, of the average NYMEX oil prices for the respective periods;

- total natural gas production was 56,006 MMcf for the nine months ended September 30, 2013, an increase of 7,855 MMcf (16 percent) from 48,151 MMcf for the nine months ended September 30, 2012. Approximately 2,900 MMcf of the increase was attributable to our acquisitions in 2012; and

- average realized natural gas price (excluding the effects of derivative activities) was $4.91 per Mcf during the nine months ended September 30, 2013, a decrease of 3 percent from $5.04 per Mcf during the nine months ended September 30, 2012. For the nine months ended September 30, 2013 and 2012, we realized approximately 133.1 percent and 194.6 percent, respectively, of the average NYMEX natural gas prices for the respective periods. Historically, approximately 55 to 80 percent of our total natural gas revenues were derived from the value of the natural gas liquids, with the remaining portion coming from the value of the dry natural gas residue. Because of our liquids-rich natural gas stream and the related value of the natural gas liquids being included in our natural gas revenues historically, our realized natural gas price (excluding the effects of derivatives) has reflected a price greater than the related NYMEX natural gas price. The deterioration of our realization percentage between comparable periods was primarily related to a combination of (i) a higher average NYMEX natural gas price between comparable periods ($3.68 per MMBtu in 2013 compared to $2.59 per MMBtu in 2012) and (ii) a lower price being received for the value of our natural gas liquids included within our natural gas revenue stream. We estimate that between the comparable periods, the value we received per gallon of natural gas liquids decreased approximately 18 percent, which is primarily the result of an increase in the supply of natural gas liquids from the significant industry drilling in liquid-prone areas.

The natural gas processing infrastructure in our New Mexico Shelf area has struggled to support the rapid growth of natural gas supply due to increased drilling by us and other producers over the recent past. During the second quarter of 2013, we noted that (i) certain additional natural gas processing capacity that was scheduled to be operational had been delayed to later in 2013 and (ii) approximately 20 MMcf per day of natural gas processing capacity, located near our recent drilling activity, had been taken out of service due to mechanical issues, which we do not have expected timing on its return to service. During the third quarter of 2013, some of the effects of these infrastructure issues were mitigated through (i) temporarily moving additional natural gas volumes to other third party processors and (ii) an improvement in operating run times and operational efficiencies of certain third party processors. We estimate these infrastructure constraints, which in part caused us to flare limited natural gas volumes, reduced our volumes for the nine months ended September 30, 2013 by approximately 465 MBoe. As a result, we noted during the second quarter of 2013 that we were redirecting a portion of our remaining New Mexico Shelf drilling budget to other areas, such as the Delaware Basin, until sufficient natural gas processing infrastructure is implemented and performing at consistent levels.

Production expenses. The following table provides the components of our total oil and natural gas production costs for the nine months ended September 30, 2013 and 2012:

	Nine Months Ended September 30,			
	2013		2012	
(in thousands, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Lease operating expenses	$ 174,844	$ 7.08	$ 132,985	$ 6.59
Taxes:				
Ad valorem	17,367	0.70	9,850	0.49
Production	123,511	5.00	100,625	4.99
Workover costs	12,573	0.51	8,181	0.41
Total oil and natural gas production expenses	$ 328,295	$ 13.29	$ 251,641	$ 12.48

Among the cost components of production expenses, we have some control over lease operating expenses and workover costs on properties we operate, but production and ad valorem taxes are directly related to commodity prices.

Lease operating expenses were $174.8 million ($7.08 per Boe) for the nine months ended September 30, 2013, which was an increase of $41.8 million (31 percent) from $133.0 million ($6.59 per Boe) for the nine months ended September 30, 2012. The increase in lease operating expenses was primarily due to increased continuing operations production from our wells successfully drilled and completed in 2012 and 2013 and the acquisitions in 2012. The increase in lease operating expenses per Boe was primarily due to (i) expansion of our production in areas with underdeveloped infrastructure, (ii) increased lease operating expenses per Boe related to our properties acquired in the PDC and Three Rivers Acquisitions as compared to our legacy properties and (iii) some minimal costs increases in services.

Ad valorem taxes have increased primarily as a result of increased valuations of our Texas properties and the increase in the number of wells primarily associated with our 2012 and 2013 drilling activity in our Texas Permian area and the Texas properties acquired in the PDC Acquisition and the Three Rivers Acquisition.

Production taxes per unit of production were $5.00 per Boe during the nine months ended September 30, 2013, a slight increase from $4.99 per Boe during the nine months ended September 30, 2012. The increase was directly related to the decrease in commodity prices offset by our increase in oil and natural gas revenues related to increased volumes. Over the same period, our per Boe prices (excluding the effects of derivatives) decreased 3 percent.

Workover expenses were approximately $12.6 million and $8.2 million for the nine months ended September 30, 2013 and 2012, respectively. The 2013 and 2012 amounts related primarily to routine workovers in the Texas Permian and New Mexico Shelf areas performed to restore production.

Exploration and abandonments expense. The following table provides a breakdown of our exploration and abandonments expense for the nine months ended September 30, 2013 and 2012:

	Nine Months Ended September 30,	
(in thousands)	**2013**	**2012**
Geological and geophysical	$ 23,597	$ 10,583
Exploratory dry hole costs	(1,915)	5,990
Leasehold abandonments	13,828	9,234
Other	2,287	1,528
Total exploration and abandonments	$ 37,797	$ 27,335

Our geological and geophysical expense consists primarily of the costs of acquiring and processing seismic data, geophysical data and core analysis mostly relating to our Delaware Basin and Texas Permian areas.

Our negative exploratory dry hole costs for the nine months ended September 30, 2013 is a result of an overestimate in 2012, partially offset by expenses on an unsuccessful lateral on a horizontal well due to mechanical issues in the Delaware Basin area.

For the nine months ended September 30, 2013, we recorded approximately $13.8 million of leasehold abandonments, which primarily related to non-core prospects in our New Mexico Shelf and Texas Permian areas. For the nine months ended September 30, 2012, we recorded approximately $9.2 million of leasehold abandonments, which primarily related to non-core prospects in our New Mexico Shelf area.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the nine months ended September 30, 2013 and 2012:

	Nine Months Ended September 30,			
	2013		2012	
(in thousands, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Depletion of proved oil and natural gas properties	$ 545,569	$ 22.08	$ 399,044	$ 19.79
Depreciation of other property and equipment	11,110	0.45	8,535	0.42
Amortization of intangible asset - operating rights	1,096	0.04	1,096	0.05
Total depletion, depreciation and amortization	$ 557,775	$ 22.57	$ 408,675	$ 20.26
Oil price used to estimate proved oil reserves at period end	$ 91.69		$ 91.48	
Natural gas price used to estimate proved natural gas reserves at period end	$ 3.60		$ 2.82	

Depletion of proved oil and natural gas properties was $545.6 million ($22.08 per Boe) for the nine months ended September 30, 2013, an increase of $146.6 million (37 percent) from $399.0 million ($19.79 per Boe) for the nine months ended September 30, 2012. The increase in depletion expense was primarily due to (i) increased production associated with new wells that were successfully drilled and completed in 2012 and 2013, (ii) increased production associated with our acquisitions in 2012 and (iii) higher depletion rates. The increase in depletion expense per Boe was primarily due to (i) the properties acquired in the Three Rivers Acquisition having a higher depletion rate per Boe than our legacy wells, (ii) drilling deeper, higher-cost wells in less proven areas and (iii) increasing production in our newer asset areas, such as the Delaware Basin, where we have a higher depletion rate than our legacy assets, such as the New Mexico Shelf, partially offset by the increase in the oil and natural gas prices between periods utilized to determine proved reserves.

More of our drilling capital is spent drilling higher-cost horizontal wells, much of which is in areas that have not had significant drilling activity or historically been developed vertically. Generally, when transitioning to a horizontal program, (i) well costs are higher as efficiencies from optimization of drilling and completion methodologies have yet to be realized and (ii) our ability to record proved reserves is limited under the rules associated with recognizing proved reserves, in part due to the limited amount of horizontal wells in the area and the lack of historical well production performance. As a result of these factors, the change in our production amongst our assets, discussed above, and our significant horizontal drilling activities in the Delaware Basin, we have seen increases in our overall depletion rate over the past year to $22.08 per Boe for the nine months ended September 30, 2013 as compared to $21.01 per Boe for the three months ended December 31, 2012.

The increase in depreciation expense was primarily associated with our increase in depreciation of other property and equipment related to buildings and other items as a result of our increased number of employees.

The amortization of the intangible asset is a result of the value assigned to the operating rights that we acquired in an acquisition. The intangible asset is currently being amortized over an estimated life of 25 years.

Impairments of long-lived assets. We periodically review our long-lived assets to be held and used, including proved oil and natural gas properties accounted for under the successful efforts method of accounting. Due primarily to downward adjustments to the economically recoverable proved reserves associated with declines in well performance and decreases in estimated realized natural gas prices, we recognized a non-cash charge against earnings of approximately $65.4 million during the nine months ended September 30, 2013, which was primarily attributable to non-core natural gas related properties in our New Mexico Shelf area.

General and administrative expenses. The following table provides components of our general and administrative expenses for the nine months ended September 30, 2013 and 2012:

	Nine Months Ended September 30,							
	2013				2012			
(in thousands, except per unit amounts)		**Amount**		**Per Boe**		**Amount**		**Per Boe**
General and administrative expenses	$	113,327	$	4.59	$	85,285	$	4.23
Non-cash stock-based compensation		25,278		1.02		21,434		1.06
Less: Third-party operating fee reimbursements		(13,485)		(0.55)		(10,725)		(0.53)
Total general and administrative expenses	$	125,120	$	5.06	$	95,994	$	4.76

General and administrative expenses were $125.1 million ($5.06 per Boe) for the nine months ended September 30, 2013, an increase of $29.1 million (30 percent) from $96.0 million ($4.76 per Boe) for the nine months ended September 30, 2012. The increase in general and administrative expenses and non-cash stock-based compensation was primarily due to (a) the nine months ended September 30, 2013 including an adjustment to our bonus accrual for services related to 2012 of approximately $5.9 million ($0.24 per Boe) and (b) an increase in the number of employees and related personnel expenses to handle our increased activities, both from (i) increased drilling and exploration activities and (ii) our acquisitions in 2012, offset in part by an approximate $2.3 million ($0.09 per Boe) net benefit to stock-based compensation related to forfeitures and modifications of stock-based awards associated with two of our former officers. The increase in general and administrative expenses per Boe was primarily due to (a) the nine months ended September 30, 2013 including an adjustment to our bonus accrual for services related to 2012, noted above, and (b) an increase in the number of employees and related personnel expenses to handle our increased activities, offset in part by (i) increased production from our wells successfully drilled and completed in 2012 and 2013, (ii) additional production associated with our acquisitions in 2012 and (iii) increased third-party operating fee reimbursements.

As the operator of certain oil and natural gas properties in which we own an interest, we earn overhead reimbursements during the drilling and production phases of the property. We earned reimbursements of $13.5 million and $10.7 million during the nine months ended September 30, 2013 and 2012, respectively. This reimbursement is reflected as a reduction of general and administrative expenses in the consolidated statements of operations. The increase in third-party operating fee reimbursements was primarily comprised of approximately $1.3 million attributable to the wells acquired in the Three Rivers Acquisition, with the remaining increase primarily due to increased reimbursements attributable to more wells operated as a result of continued drilling activity period over period.

Gain (loss) on derivatives not designated as hedges. The following table sets forth the gain (loss) on derivatives not designated as hedges for the nine months ended September 30, 2013 and 2012:

(in thousands)	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Gain (loss) on derivatives not designated as hedges:		
Oil derivatives	$ (172,698)	$ 109,386
Natural gas derivatives	15,395	156
Total gain (loss) on derivatives not designated as hedges	$ (157,303)	$ 109,542

The following table represents the Company's cash receipts from (payments on) derivatives not designated as hedges for the nine months ended September 30, 2013 and 2012:

(in thousands)	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Cash receipts from (payments on) derivatives not designated as hedges:		
Oil derivatives	$ (42,528)	$ (8,374)

Natural gas derivatives		4,844		889
Total cash receipts from (payments on) derivatives not designated as hedges	$	(37,684)	$	(7,485)

Our earnings are affected by the changes in value of our derivatives portfolio between periods and the related cash settlements of those derivatives, which can be volatile to our earnings. To the extent the future commodity price outlook declines between measurement periods, we will have mark-to-market gains, while to the extent future commodity price outlook increases between measurement periods, we will have mark-to-market losses.

Interest expense. The following table sets forth interest expense, weighted average interest rates and weighted average debt balances for the nine months ended September 30, 2013 and 2012:

	Nine Months Ended			
(dollars in thousands)		**2013**		**2012**
Interest expense	$	162,180	$	129,073
Weighted average interest rate - credit facility		2.3%		2.4%
Weighted average interest rate - senior notes		6.2%		6.7%
Total weighted average interest rate		5.8%		5.6%
Weighted average balance of credit facility	$	330,571	$	667,867
Weighted average balance of senior notes		3,039,630		2,051,481
Total weighted average balance of debt	$	3,370,201	$	2,719,348

The increase in weighted average debt balance for the nine months ended September 30, 2013 as compared to the corresponding period in 2012 was due primarily to (i) borrowings associated with our acquisitions in 2012 and (ii) timing of our capital expenditures. The increase in interest expense was due to an overall increase in the weighted average balance of debt and a slightly increased weighted average interest rate due to (i) the weighted average balance of our senior notes bearing a higher interest rate than our credit facility borrowings.

Loss on extinguishment of debt. We recorded a loss on extinguishment of debt of $28.6 million for the nine months ended September 30, 2013 related to the tender offer and redemption of our 8.625% Notes.

Income tax provisions. We recorded an income tax expense of $86.0 million and $204.3 million for the nine months ended September 30, 2013 and 2012, respectively. The effective income tax rate for the nine months ended September 30, 2013 and 2012 was 39.3 percent and 38.5 percent, respectively.

During the nine months ended September 30, 2013 and 2012, we recorded expense of $1.3 million and $0.2 million, respectively, associated with revisions of estimates based on filing our 2012 and 2011 tax returns, respectively. During the nine months ended September 30, 2013, this revision increased the effective rate by 0.6 percent from 39.3 percent.

Income from discontinued operations, net of tax. In December 2012, we closed the sale of certain of our non-core assets for cash consideration of approximately $503.1 million, which resulted in a pre-tax gain of approximately $0.9 million. As a result of post-closing adjustments during the nine months ended September 30, 2013, we made a positive adjustment to our pre-tax gain of approximately $19.6 million. We recognized income from discontinued operations of $12.1 million and $29.4 million for the nine months ended September 30, 2013 and 2012, respectively.

The results of operations of these assets are reported as discontinued operations in the accompanying consolidated statements of operations, and are described in more detail in Note M of the Condensed Notes to Consolidated Financial Statements included in “Item 1. Consolidated Financial Statements (Unaudited).”

Capital Commitments, Capital Resources and Liquidity

Capital commitments. Our primary needs for cash are development, exploration and acquisition of oil and natural gas assets, payment of contractual obligations and working capital obligations. Funding for these cash needs may be provided by any combination of internally-generated cash flow, financing under our credit facility or proceeds from the disposition of assets or alternative financing sources, as discussed in "— Capital resources" below.

Oil and natural gas properties. Our costs incurred on oil and natural gas properties, excluding acquisitions and asset retirement obligations, during the nine months ended September 30, 2013 and 2012 totaled $1,360.8 million and $1,130.9 million, respectively.

2013 revised capital budget. For 2013, we increased our capital budget by approximately $200 million to a total of approximately $1.8 billion, excluding the costs of acquisitions other than customary leasehold purchases of acreage. Based on current commodity prices and capital costs, we believe our 2013 expected capital expenditures, excluding the effects of acquisitions, will exceed our 2013 cash flow. We have funded, and expect to continue to fund, the shortfall, if any, with borrowings under our credit facility.

2014 capital budget. In November 2013, we announced our 2014 capital budget of approximately $2.3. Our 2014 capital program is expected to continue focusing on drilling in the Delaware Basin and Midland Basin. The 2014 capital budget, based on our current expectations of commodity prices and cost, will exceed our cash flow. We expect our cash flow and borrowings under our credit facility will be sufficient to fund our budgeted capital expenditure needs during 2014. However, our capital budget is largely discretionary, and if we experience sustained oil and natural gas prices significantly below the current levels or substantial increases in our costs, we may reduce our capital spending program to manage the level of capital outspend.

Three-year accelerated growth plan. We have adopted an accelerated drilling program for the next three years which we expect will double production by 2016. By accelerating activity across our assets, we believe that we can deliver average annual organic production growth over the next three years in excess of our historical annual average while increasing oil mix and reducing leverage ratios.

Although we cannot provide any assurance, we have historically attempted to fund our non-acquisition expenditures with our available cash and cash flow as adjusted from time to time; however, we may also use our credit facility, or other alternative financing sources, to fund such expenditures. The actual amount and timing of our expenditures may differ materially from our estimates as a result of, among other things, actual drilling results, the timing of expenditures by third parties on projects that we do not operate, the availability of drilling rigs and other services and equipment, regulatory, technological and competitive developments and market conditions. In addition, under certain circumstances, we would consider increasing or reallocating our capital spending plans.

Other than the customary purchase of leasehold acreage, our capital budgets are exclusive of acquisitions. We do not have a specific acquisition budget, since the timing and size of acquisitions are difficult to forecast. We evaluate opportunities to purchase or sell oil and natural gas properties in the marketplace and could participate as a buyer or seller of properties at various times. We seek to acquire oil and natural gas properties that provide opportunities for the addition of reserves and production through a combination of development, high-potential exploration and control of operations that will allow us to apply our operating expertise.

Acquisitions. Our expenditures for acquisitions of proved and unproved properties during the three months ended September 30, 2013 and 2012 totaled approximately $14 million and $1.0 billion, respectively, and approximately $61.2 million and $1.3 billion during the nine months ended September 30, 2013 and 2012. The significant acquisitions of proved properties during the nine months ended September 30, 2012 primarily related to the PDC Acquisition and Three Rivers Acquisition. Expenditures for leasehold acreage acquisitions (which are expenditures we generally provide for in our planned capital expenditures) included in the total above were approximately $58.7 million and $31.3 million for the nine months ended September 30, 2013 and 2012, respectively.

Divestitures. In December 2012, we closed the sale of certain of our non-core assets, a portion of which were acquired in the Three Rivers Acquisition, for cash consideration of approximately $503.1 million, which resulted in a pre-tax gain of approximately $0.9 million (included in discontinued operations). For the nine months ended September 30, 2012, these assets produced an average of 5,043 Boe per day, on a pro forma basis for the Three Rivers Acquisition. We estimate that the proved reserves of these assets at closing were approximately 35.3 MMBoe. We used the net proceeds from this divestiture to repay a portion of the outstanding borrowings under our credit facility.

Contractual obligations. Our contractual obligations include long-term debt, cash interest expense on debt, operating lease obligations, drilling commitments, employment agreements with officers, derivative liabilities and other obligations. Since December 31, 2012, the material changes in our contractual obligations included a $487.5 million increase in outstanding long-term debt, a $216.2 million increase in cash interest expense on debt and a $81.8 million increase in our net commodity derivative liability. See Note I of the Condensed Notes to Consolidated Financial Statements included in "Item 1. Consolidated Financial Statements (Unaudited)" for additional information regarding our long-term debt and "Item 3. Quantitative and Qualitative Disclosures About Market Risk" for information regarding the interest on our long-term debt and information on changes in the fair value of our open derivative obligations during the nine months ended September 30, 2013.

Off-balance sheet arrangements. Currently, we do not have any material off-balance sheet arrangements.

Capital resources. Our primary sources of liquidity have historically been cash flows generated from operating activities (including the cash settlements received from (paid on) derivatives not designated as hedges presented in our investing activities) and borrowings under our credit facility. Based on current commodity prices and capital costs, we believe our 2013 expected capital expenditures, excluding the effects of acquisitions, will exceed our 2013 cash flow, and we have funded, and expect to continue to fund, the shortfall with borrowings under our credit facility. We believe that we have adequate availability under our credit facility to fund any cash flow deficits.

The following table summarizes our changes in cash and cash equivalents for the nine months ended September 30, 2013 and 2012:

	Nine Months Ended September 30,	
(in thousands)	**2013**	**2012**
Net cash provided by operating activities	$ 944,644	$ 845,636
Net cash used in investing activities	(1,472,096)	(2,367,407)
Net cash provided by financing activities	524,594	1,521,720
Net decrease in cash and cash equivalents	$ (2,858)	$ (51)

Cash flow from operating activities. The increase in operating cash flows during the nine months ended September 30, 2013 as compared to 2012 was primarily due to an increase in oil and natural gas revenues of approximately $345.5 million; offset in part by (i) cash increases in oil and natural gas production costs of approximately $76.7 million, (ii) cash increases in general and administrative expense and interest expense of approximately $29.1 million and $33.1 million, respectively, and (iii) approximately $15.8 million of negative variances in working capital changes.

Our net cash provided by operating activities includes a reduction of $106.2 million and $90.4 million for the nine months ended September 30, 2013 and 2012, respectively, associated with changes in operating assets and liabilities. Changes in operating assets and liabilities adjust for the timing of receipts and payments of actual cash.

Cash flow used in investing activities. During the nine months ended September 30, 2013 and 2012, we invested $1,426.3 million and $2,334.2 million, respectively, for capital expenditures on oil and natural gas properties. The primary reason for the differences in the costs incurred and cash flow expenditures is the timing of payments. The 2013 and 2012 expenditures were funded in part from borrowings under our credit facility. Cash flows used in investing activities were lower during the nine months ended September 30, 2013 as compared to 2012, primarily due to our $189.2 million PDC Acquisition and $1.0 billion Three Rivers Acquisition in 2012.

Cash flow from financing activities. During the nine months ended September 30, 2013 and 2012, we had net cash provided by financing activities of $524.6 million and $1,521.7 million, respectively. The primary reason for the decrease was our financing activities during 2012 related to the PDC Acquisition and Three Rivers Acquisition.

During the nine months ended September 30, 2013 and 2012 we completed the following significant activities:

• In June 2013, we issued $850 million in aggregate principal amount of 5.5% senior notes due 2023 at 103.75 percent of par, for which we received net proceeds of approximately $867.8 million. We used a portion of the net proceeds from the Offering to fund the tender offer and redemption of the 8.625% Notes at a price of 106.922 percent of the unpaid principal amount. The remaining proceeds were used to pay down amounts outstanding on the credit facility. See Note I of the Condensed Notes to Consolidated Financial Statements included in "Item 1. Consolidated Financial Statements (Unaudited)" for additional information regarding our debt balance at September 30, 2013.

- In August 2012, we issued $700 million in aggregate principal amount of 5.5% senior notes due 2023 at par, for which we received net proceeds of approximately $688.6 million. We used the net proceeds to repay a portion of the borrowings outstanding under our credit facility.

- In March 2012, we issued $600 million in aggregate principal amount of 5.5% senior notes due 2022 at par, for which we received net proceeds of approximately $590.0 million. We used the net proceeds to repay a portion of the borrowings outstanding under our credit facility.

Our credit facility has a maturity date of April 25, 2016. Our borrowing base is $3.0 billion until the next scheduled borrowing base redetermination in April 2014, and commitments from our bank group total $2.5 billion. Between scheduled borrowing base redeterminations, we and the lenders (requiring a 66 2/3 percent vote) may each request one special redetermination. At September 30, 2013, our availability to borrow additional funds was approximately $2.3 billion based on bank commitments of $2.5 billion.

In conducting our business, we may utilize various financing sources, including the issuance of (i) fixed and floating rate debt, (ii) convertible securities, (iii) preferred stock, (iv) common stock and (v) other securities. Over the last three years, we have demonstrated our use of the capital markets by issuing senior unsecured debt. However, there are no assurances that we can access the capital markets to obtain additional funding, if needed, and at what cost and terms. We may also sell assets and issue securities in exchange for oil and natural gas assets or interests in oil and natural gas companies. Additional securities may be of a class senior to common stock with respect to such matters as dividends and liquidation rights and may also have other rights and preferences as determined from time to time by our board of directors. Utilization of some of these financing sources may require approval from the lenders under our credit facility.

Liquidity. Our principal sources of short-term liquidity are cash on hand and available borrowing capacity under our credit facility. At September 30, 2013, we had $22,000 of cash on hand.

At September 30, 2013, the commitments under our credit facility were $2.5 billion, which provided us with approximately $2.3 billion of available borrowing capacity. At September 30, 2013, we have a working capital deficit of approximately $266.6 million, which we expect to fund with borrowings under our credit facility, which would reduce our available borrowing capacity under our credit facility. Upon a redetermination, our $3.0 billion borrowing base could be substantially reduced, which could affect our liquidity.

Debt ratings. We receive debt credit ratings from Standard & Poor's Ratings Group, Inc. ("S&P") and Moody's Investors Service, Inc. ("Moody's"), which are subject to regular reviews. S&P's corporate rating for us is "BB+" with a stable outlook. Moody's corporate rating for us is "Ba2" with a stable outlook. S&P and Moody's consider many factors in determining our ratings including: production growth opportunities, liquidity, debt levels and asset and reserve mix. A reduction in our debt ratings could negatively affect our ability to obtain additional financing or the interest rate, fees and other terms associated with such additional financing.

Book capitalization and current ratio. Our book capitalization at September 30, 2013 was $7.2 billion, consisting of debt of $3.6 billion and stockholders' equity of $3.6 billion. Our debt to book capitalization was 50 percent and 47 percent at September 30, 2013 and December 31, 2012, respectively. Our ratio of current assets to current liabilities was 0.70 to 1.0 at September 30, 2013 as compared to 0.62 to 1.0 at December 31, 2012.

Inflation and changes in prices. Our revenues, the value of our assets, and our ability to obtain bank financing or additional capital on attractive terms have been and will continue to be affected by changes in commodity prices and the costs to produce our reserves. Commodity prices are subject to significant fluctuations that are beyond our ability to control or predict. During the nine months ended September 30, 2013, we received an average of $91.89 per barrel of oil and $4.91 per Mcf of natural gas before consideration of commodity derivative contracts compared to $90.56 per barrel of oil and $5.04 per Mcf of natural gas in the nine months ended September 30, 2012. Although certain of our costs are affected by general inflation, inflation does not normally have a significant effect on our business. In a trend that began in 2004, and that has continued until recently, oil prices have increased significantly. The higher oil price led to increased activity in the industry and, consequently, rising costs. These cost trends have put pressure not only on our operating costs, but also on capital costs.

Critical Accounting Policies, Practices and Estimates

Our historical consolidated financial statements and related condensed notes to consolidated financial statements contain information that is pertinent to our management's discussion and analysis of financial condition and results of operations. Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires that our management make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. However, the accounting principles used by us generally do not change our reported cash flows or liquidity. Interpretation of the existing rules must be done and judgments made on how the specifics of a given rule apply to us.

In management's opinion, the more significant reporting areas impacted by management's judgments and estimates are revenue recognition, the choice of accounting method for oil and natural gas activities, oil and natural gas reserve estimation, asset retirement obligations, impairment of long-lived assets, valuation of stock-based compensation, valuation of business combinations and valuation of financial derivative instruments. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters. Actual results could differ from the estimates, as additional information becomes known.

There have been no material changes in our critical accounting policies and procedures during the nine months ended September 30, 2013. See our disclosure of critical accounting policies in "Item 8. Financial Statements and Supplementary Data" of our Annual Report on Form 10-K for the year ended December 31, 2012, filed with the United States Securities and Exchange Commission (the "SEC") on February 22, 2013.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The following market risk disclosures should be read in conjunction with the quantitative and qualitative disclosures about market risk contained in our Annual Report on Form 10-K for the year ended December 31, 2012.

We are exposed to a variety of market risks including credit risk, commodity price risk and interest rate risk. We address these risks through a program of risk management which includes the use of derivative instruments. The following quantitative and qualitative information is provided about financial instruments to which we are a party at September 30, 2013, and from which we may incur future gains or losses from changes in market interest rates or commodity prices and losses from extension of credit. We do not enter into derivative or other financial instruments for speculative or trading purposes.

Hypothetical changes in interest rates and commodity prices chosen for the following estimated sensitivity analysis are considered to be reasonably possible near-term changes generally based on consideration of past fluctuations for each risk category. However, since it is not possible to accurately predict future changes in interest rates and commodity prices, these hypothetical changes may not necessarily be an indicator of probable future fluctuations.

Credit risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our oil and natural gas production, which we market to energy marketing companies and refineries and to a lesser extent our derivative counterparties. We monitor our exposure to these counterparties primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty’s creditworthiness. Although we have not generally required our counterparties to provide collateral to support their obligation to us, we may, if circumstances dictate, require collateral in the future. In this manner, we reduce credit risk.

We have entered into International Swap Dealers Association Master Agreements (“ISDA Agreements”) with each of our derivative counterparties. The terms of the ISDA Agreements provide us and the counterparties with rights of set off upon the occurrence of defined acts of default by either us or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party. See Note H of the Condensed Notes to Consolidated Financial Statements included in “Item 1. Consolidated Financial Statements (Unaudited)” for additional information regarding our derivative activities.

Commodity price risk. We are exposed to market risk as the prices of our commodities are subject to fluctuations resulting from changes in supply and demand. To reduce our exposure to changes in the prices of our commodities we have entered into, and may in the future enter into, additional commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Our commodity price risk management activities could have the effect of reducing net income and the value of our securities. An average increase in the commodity price of $10.00 per barrel of oil and $1.00 per MMBtu of natural gas from the commodity prices at September 30, 2013, would have resulted in a net unrealized loss on our commodity price risk management contracts of approximately $341.8 million.

At September 30, 2013, we had (i) oil price swaps that settle on a monthly basis covering future oil production from October 1, 2013 through June 30, 2017 and (ii) oil basis swaps covering our Midland to Cushing basis differential from October 1, 2013 to December 31, 2014. See Note H of the Condensed Notes to Consolidated Financial Statements included in “Item 1. Consolidated Financial Statements (Unaudited)” for additional information on our commodity derivative instruments. The average NYMEX oil price for the nine months ended September 30, 2013, was $98.21 per Bbl. At November 4, 2013, the NYMEX oil price was $94.62 per Bbl.

At September 30, 2013, we had (i) natural gas price swaps that settle on a monthly basis covering future natural gas production from October 1, 2013 through December 31, 2013, (ii) natural gas collars covering future natural gas production from January 1, 2014 to December 31, 2014 and (iii) natural gas basis swaps covering our basis differential between the El Paso Permian delivery point and the NYMEX-Henry Hub delivery point from October 1, 2013 to December 31, 2013. See Note H of the Condensed Notes to Consolidated Financial Statements included in “Item 1. Consolidated Financial Statements (Unaudited)” for additional information on our commodity derivative instruments. The average NYMEX natural gas price for the nine months ended September 30, 2013, was $3.69 per MMBtu. At November 4, 2013, the NYMEX natural gas price was $3.45 per MMBtu.

A decrease in the average forward NYMEX oil and natural gas prices below those at September 30, 2013, would decrease the fair value liability of our commodity derivative contracts from their recorded balance at September 30, 2013.

Changes in the recorded fair value of the undesignated commodity derivative contracts are marked to market through earnings as unrealized gains or losses. The potential decrease in our fair value liability would be recorded in earnings as an unrealized gain. However, an increase in the average forward NYMEX oil and natural gas prices above that at September 30, 2013, would increase the fair value liability of our commodity derivative contracts from their recorded balance at September 30, 2013. The potential decrease in our fair value liability would be recorded in earnings as an unrealized loss. We are currently unable to estimate the effects on the earnings of future periods resulting from changes in the market value of our commodity derivative contracts.

The fair value of our derivative instruments is determined based on our valuation models. We did not change our valuation method during the nine months ended September 30, 2013, to which we were a party. See Note H of the Condensed Notes to Consolidated Financial Statements included in "Item 1. Consolidated Financial Statements (Unaudited)" for additional information regarding our derivative instruments. The following table reconciles the changes that occurred in the fair value of our derivative instruments during the nine months ended September 30, 2013:

(in thousands)		**Commodity Derivative Instruments Net Assets (Liabilities) (a)**
Fair value of contracts outstanding at December 31, 2012	$	25,078
Changes in fair values (b)		(157,303)
Contract maturities		37,684
Fair value of contracts outstanding at September 30, 2013	$	(94,541)

(a) Represents the fair values of open derivative contracts subject to market risk.
(b) At inception, new derivative contracts entered into by us have no intrinsic value.

Interest rate risk. Our exposure to changes in interest rates relates primarily to debt obligations. We manage our interest rate exposure by limiting our variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. To reduce our exposure to changes in interest rates we have entered into, and may in the future enter into additional interest rate risk management arrangements for a portion of our outstanding debt. The agreements that we have entered into generally have the effect of providing us with a fixed interest rate for a portion of our variable rate debt. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We are exposed to changes in interest rates as a result of our credit facility, and the terms of our credit facility require us to pay higher interest rate margins as we utilize a larger percentage of our available commitments.

We had total indebtedness of $207.6 million outstanding under our credit facility at September 30, 2013. The impact of a one percent increase in interest rates on this amount of debt would result in increased annual interest expense of approximately $2.1 million.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective at September 30, 2013 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting. There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

We are a party to proceedings and claims incidental to our business. While many of these other matters involve inherent uncertainty, we believe that the liability, if any, ultimately incurred with respect to such other proceedings and claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future results of operations. We will continue to evaluate proceedings and claims involving us on a regular basis and will establish and adjust any reserves as appropriate to reflect our assessment of the then current status of the matters.

Item 1A. Risk Factors

In addition to the other information set forth in this Quarterly Report on Form 10-Q, you should carefully consider the risks discussed in our Annual Report on Form 10-K for the year ended December 31, 2012, under the headings “Item 1. Business – Competition,” “— Marketing Arrangements” and “— Applicable Laws and Regulations,” “Item 1A. Risk Factors,” 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Item 7A. Quantitative and Qualitative Disclosure About Market Risk,” which risks could materially affect our business, financial condition or future results. There have been no material changes in our risk factors from those described in our Annual Report on Form 10-K for the year ended December 31, 2012. The risks described in this Quarterly Report on Form 10-Q and in our Annual Report on Form 10-K are not the only risks facing our company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results.

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

Period	Total number of shares withheld (a)	Average price per share	Total number of shares purchased as part of publicly announced plans	Maximum number of shares that may yet be purchased under the plan
July 1, 2013 - July 31, 2013	600	$ 88.95	-	

August 1, 2013 - August 31, 2013	876	$ 95.29	-
September 1, 2013 - September 30, 2013	754	$ 102.43	-

(a) Represents shares that were withheld by us to satisfy tax withholding obligations of certain of our officers and key employees that arose upon the lapse of restrictions on restricted stock.

Item 6. Exhibits

Exhibit Number	Exhibit
3.1	Restated Certificate of Incorporation (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on August 8, 2007, and incorporated herein by reference).
3.2	Second Amended and Restated Bylaws of Concho Resources Inc., as amended November 7, 2012 (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on November 8, 2012, and incorporated herein by reference).
4.1	Specimen Common Stock Certificate (filed as Exhibit 4.1 to the Company's Annual Report on Form 10-K on February 22, 2013, and incorporated herein by reference).
10.1	Twelfth Amendment to Amended and Restated Credit Agreement, dated as of October 29, 2013, among Concho Resources Inc., the lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on October 29, 2013, and incorporated herein by reference).
** 10.2 (a)	Termination of Consulting Agreement dated August 14, 2013 by and between Concho Resources Inc. and Steven L. Beal.
31.1 (a)	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2 (a)	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1 (b)	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2 (b)	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

101.INS (a)	XBRL Instance Document.
101.SCH (a)	XBRL Schema Document.
101.CAL (a)	XBRL Calculation Linkbase Document.
101.DEF (a)	XBRL Definition Linkbase Document.
101.LAB (a)	XBRL Labels Linkbase Document.
101.PRE (a)	XBRL Presentation Linkbase Document.

(a) Filed herewith.

(b) Furnished herewith.

** Management contract or compensatory plan or agreement.

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 thereunto duly authorized.

CONCHO RESOURCES INC.

Date:	November 7, 2013	By	/s/ Timothy A. Leach
			Timothy A. Leach Director, Chairman of the Board of Directors, Chief Executive Officer and President (Principal Executive Officer)
		By	/s/ Darin G. Holderness
			Darin G. Holderness Senior Vice President and Chief Financial Officer (Principal Financial Officer)
		By	/s/ Brenda R. Schroer
			Brenda R. Schroer Vice President and Chief Accounting Officer (Principal Accounting Officer)

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