UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the Quarterly Period ended September 30, 2014

Commission File No. 001-31446

CIMAREX ENERGY CO.

1700 Lincoln Street, Suite 3700

Denver, Colorado 80203

(303) 295-3995

Former Address

1700 Lincoln Street, Suite 1800

Denver, Colorado 80203

Incorporated in the State of Delaware	Employer Identification No. 45-0466694

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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	Accelerated filer	Non-accelerated filer (Do not check if a smaller reporting company)	Smaller reporting company

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

The number of shares of Cimarex Energy Co. common stock outstanding as of September 30, 2014 was 87,248,508.

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GLOSSARY

Bbl/d—Barrels (of oil or natural gas liquids) per day

Bbls—Barrels (of oil or natural gas liquids)

Bcf—Billion cubic feet

Bcfe—Billion cubic feet equivalent

Btu—British thermal unit

MBbls—Thousand barrels

Mcf—Thousand cubic feet (of natural gas)

Mcfe—Thousand cubic feet equivalent

MMBbl/MMBbls—Million barrels

MMBtu—Million British Thermal Units

MMcf—Million cubic feet

MMcf/d—Million cubic feet per day

MMcfe—Million cubic feet equivalent

MMcfe/d—Million cubic feet equivalent per day

Net Acres—Gross acreage multiplied by working interest percentage

Net Production—Gross production multiplied by net revenue interest

NGL or NGLs—Natural gas liquids

Tcf—Trillion cubic feet

Tcfe—Trillion cubic feet equivalent

Energy equivalent is determined using the ratio of one barrel of crude oil, condensate or NGL to six Mcf of natural gas

CAUTIONARY INFORMATION ABOUT FORWARD-LOOKING STATEMENTS

Throughout this Form 10-Q, we make statements that may be deemed "forward-looking" statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities and Exchange Act of 1934. These forward-looking statements include, among others, statements concerning our outlook with regard to timing and amount of future production of oil and gas, price realizations, amounts, nature and timing of capital expenditures for exploration and development, plans for funding operations and capital expenditures, drilling of wells, operating costs and other expenses, marketing of oil, gas, and NGLs and other statements of expectations, beliefs, future plans and strategies, anticipated events or trends, and similar expressions concerning matters that are not historical facts. The forward-looking statements in this report are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in or implied by the statements.

These risks and uncertainties include, but are not limited to, fluctuations in the price we receive for our oil and gas production, reductions in the quantity of oil and gas sold due to decreased industry-wide demand and/or curtailments in production from specific properties or areas due to mechanical, transportation, marketing, weather or other problems, operating and capital expenditures that are either significantly higher or lower than anticipated because the actual cost of identified projects varied from original estimates and/or from the number of exploration and development opportunities being greater or fewer than currently anticipated, and increased financing costs due to a significant increase in interest rates. In addition, exploration and development opportunities that we pursue may not result in economic, productive oil and gas properties. There are also numerous uncertainties inherent in estimating quantities of proved reserves, projecting future rates of production and the timing of development expenditures. These and other risks and uncertainties affecting us are discussed in greater detail in this report and in our other filings with the Securities and Exchange Commission.

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PART I

ITEM 1 - Financial Statements

CIMAREX ENERGY CO.

Condensed Consolidated Balance Sheets

(Unaudited)

	September 30, 2014	December 31, 2013
	(in thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 563,657	$ 4,531
Receivables, net	430,702	367,754
Oil and gas well equipment and supplies	93,012	66,772
Deferred income taxes	13,544	16,854
Derivative instruments	1,090	4,268
Prepaid expenses	6,603	7,867
Other current assets	1,929	1,093
Total current assets	1,110,537	469,139
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	13,842,214	12,863,961
Unproved properties and properties under development, not being amortized	865,058	585,361
	14,707,272	13,449,322
Less — accumulated depreciation, depletion and amortization	(8,049,016)	(7,483,685)
Net oil and gas properties	6,658,256	5,965,637
Fixed assets, net	195,854	146,918
Goodwill	620,232	620,232
Other assets, net	59,215	51,209
	$ 8,644,094	$ 7,253,135
Liabilities and Stockholders’ Equity		
Current liabilities:		
Accounts payable	$ 123,388	$ 116,110
Accrued liabilities	474,074	412,495
Derivative instruments	156	389
Revenue payable	218,025	154,173
Total current liabilities	815,643	683,167
Long-term debt	1,500,000	924,000

Deferred income taxes	1,710,662	1,459,841
Other liabilities	187,815	163,919
Total liabilities	4,214,120	3,230,927
Commitments and contingencies		
Stockholders’ equity:		
Preferred stock, $0.01 par value, 15,000,000 shares authorized, no shares issued	—	—
Common stock, $0.01 par value, 200,000,000 shares authorized, 87,248,508 and 87,152,197 shares issued, respectively	872	872
Paid-in capital	1,988,257	1,970,113
Retained earnings	2,439,794	2,050,034
Accumulated other comprehensive income	1,051	1,189
	4,429,974	4,022,208
	$ 8,644,094	$ 7,253,135

See accompanying notes to consolidated financial statements.

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CIMAREX ENERGY CO.

Consolidated Statements of Income and Comprehensive Income

(Unaudited)

	For the Three Months Ended September 30, 2014	For the Three Months Ended September 30, 2013	For the Nine Months Ended September 30, 2014	For the Nine Months Ended September 30, 2013
	(in thousands, except per share data)			
Revenues:				
Gas sales	$ 176,539	$ 118,824	$ 519,139	$ 346,492
Oil sales	348,276	371,881	1,028,229	933,879
NGL sales	111,701	58,922	297,128	168,106
Gas gathering and other	12,951	11,380	39,699	32,951
Gas marketing, net	273	329	1,430	21
	649,740	561,336	1,885,625	1,481,449
Costs and expenses:				
Depreciation, depletion and amortization	219,359	159,182	588,279	442,851
Asset retirement obligation	1,420	1,797	8,288	7,080
Production	89,084	76,166	250,310	214,985
Transportation, processing, and other operating	54,573	25,838	145,299	66,494
Gas gathering and other	8,588	6,970	27,413	18,310
Taxes other than income	33,510	31,104	99,454	84,039
General and administrative	20,240	19,003	57,523	57,416
Stock compensation	3,603	3,347	10,875	10,459
(Gain) loss on derivative instruments, net	(9,229)	10,824	8,960	(1,233)
Other operating, net	(181)	2,507	34	7,804
	420,967	336,738	1,196,435	908,205
Operating income	228,773	224,598	689,190	573,244
Other (income) and expense:				
Interest expense	20,879	13,954	51,645	41,272
Capitalized interest	(10,005)	(7,286)	(25,870)	(23,868)
Other, net	(11,123)	(2,263)	(22,207)	(13,637)
Income before income tax	229,022	220,193	685,622	569,477
Income tax expense	84,707	81,823	254,210	211,615
Net income	$ 144,315	$ 138,370	$ 431,412	$ 357,862
Earnings per share to common stockholders:				
Basic				
Distributed	$ 0.16	$ 0.14	$ 0.48	$ 0.42
Undistributed	1.49	1.45	4.46	3.70
	$ 1.65	$ 1.59	$ 4.94	$ 4.12
Diluted				

Distributed	$ 0.16	$ 0.14	$ 0.48	$ 0.42
Undistributed	1.49	1.45	4.46	3.70
	$ 1.65	$ 1.59	$ 4.94	$ 4.12
Comprehensive income:				
Net income	$ 144,315	$ 138,370	$ 431,412	$ 357,862
Other comprehensive income:				
Change in fair value of investments, net of tax	(123)	302	(139)	401
Total comprehensive income	$ 144,192	$ 138,672	$ 431,273	$ 358,263

See accompanying notes to consolidated financial statements.

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CIMAREX ENERGY CO.

Condensed Consolidated Statements of Cash Flows

(Unaudited)

	For the Nine Months Ended September 30,	
	2014	2013
	(in thousands)	
Cash flows from operating activities:		
Net income	$ 431,412	$ 357,862
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	588,279	442,851
Asset retirement obligation	8,288	7,080
Deferred income taxes	254,210	211,615
Stock compensation	10,875	10,459
(Gain) loss on derivative instruments	8,960	(1,233)
Settlements on derivative instruments	(6,015)	(4,332)
Changes in non-current assets and liabilities	(1,873)	9,102
Other, net	(2,384)	(685)
Changes in operating assets and liabilities:		
Receivables, net	(63,091)	(88,131)
Other current assets	(26,110)	9,799
Accounts payable and accrued liabilities	69,419	(13,639)
Net cash provided by operating activities	1,271,970	940,748
Cash flows from investing activities:		
Oil and gas expenditures	(1,630,929)	(1,165,555)
Sales of oil and gas assets	451,710	37,707
Sales of other assets	8,178	31,252
Other expenditures	(76,784)	(34,657)
Net cash used by investing activities	(1,247,825)	(1,131,253)
Cash flows from financing activities:		
Net bank debt borrowings	(174,000)	150,000
Proceeds from other long-term debt	750,000	—
Financing costs incurred	(11,616)	(100)
Dividends paid	(39,932)	(34,570)
Issuance of common stock and other	10,529	10,168
Net cash provided by financing activities	534,981	125,498
Net change in cash and cash equivalents	559,126	(65,007)
Cash and cash equivalents at beginning of period	4,531	69,538
Cash and cash equivalents at end of period	$ 563,657	$ 4,531

See accompanying notes to consolidated financial statements.

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

September 30, 2014

(Unaudited)

1. Basis of Presentation

The accompanying unaudited financial statements have been prepared by Cimarex Energy Co. ("Cimarex", "we", or "us") pursuant to rules and regulations of the Securities and Exchange Commission (SEC). Accordingly, certain disclosures required by accounting principles generally accepted in the United States and normally included in Annual Reports on Form 10-K have been omitted. Although management believes that our disclosures in these interim financial statements are adequate, they should be read in conjunction with the financial statements, summary of significant accounting policies, and footnotes included in our 2013 Annual Report on Form 10-K.

In the opinion of management, the accompanying financial statements reflect all adjustments necessary to present fairly our financial position, results of operations, and cash flows for the periods and as of the dates shown. We have evaluated subsequent events through the date of this filing.

Oil and Gas Properties

We use the full cost method of accounting for our oil and gas operations. Accounting rules require us to perform a quarterly ceiling test calculation to test our oil and gas properties for possible impairment. The primary components impacting this calculation are commodity prices, reserve quantities added and produced, overall exploration and development costs, depletion expense, and tax effects. If the net capitalized cost of our oil and gas properties subject to amortization (the carrying value) exceeds the ceiling limitation, the excess would be charged to expense. The ceiling limitation is equal to the sum of the present value discounted at 10% of estimated future net cash flows from proved reserves, the cost of properties not being amortized, the lower of cost or estimated fair value of unproven properties included in the costs being amortized, and all related tax effects.

At September 30, 2014, the calculated value of the ceiling limitation exceeded the carrying value of our oil and gas properties subject to the test, and no impairment was necessary. However, a decline of 9% in the value of the ceiling limitation would have resulted in an impairment. If pricing conditions decline, or if there is a negative impact on one or more of the other components of the calculation, we may incur a full cost ceiling impairment related to our oil and gas properties in future quarters.

Oil, Gas and NGL sales

Oil, gas and NGL sales are based on the sales method by which revenue is recognized on actual volumes sold to purchasers. There is a ready market for our products and sales occur soon after production. The determination to record and separately disclose NGL volumes is based on the location at which both title contractually transfers from Cimarex to a buyer and the associated volumes can be physically quantified. For those NGL volumes that we have recorded and disclosed separately, contractual title of the volumes has passed from Cimarex to a buyer at a point where the NGL volumes have been physically separated from the production stream. Should title contractually transfer before NGL volumes can be physically separated and quantified (typically at the wellhead), we do not report separate NGL volumes and the value of the NGLs are included in the reported value of the disclosed gas volumes.

Under certain contracts, when NGLs are extracted from the gas stream, processors receive a portion of the sales value from both the residue gas and the NGLs as a processing fee and remit the contractual proceeds to us. Prior to 2014, revenue was recognized net of these processing fees for residue gas and NGLs sold under these contracts as allowed under EITF 00-10 Accounting for Shipping and Handling Fees and Costs.   Increasing NGL production combined with the impact of recent changes to these contracts has resulted in processing costs becoming more significant. Accordingly, we have changed our policy to record these processing costs with operating costs as allowed under EITF 00-10. Beginning in 2014, our realized prices for sales under these contracts reflect the value of 100% of the residue gas and NGLs yielded by processing, rather than the value associated with the contractual proceeds we received. The related processing fees now are included in “transportation, processing and other operating” costs. The effect of this change in the current quarter and nine months ended was that total revenue was

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

September 30, 2014

(Unaudited)

$14.2 million and $38.2 million higher, respectively, with an offsetting increase in total transportation, processing and other operating costs. There was no impact on operating income. Financial statements for periods prior to 2014 have not been reclassified to reflect this change in accounting treatment as it was impracticable to do so.

Use of Estimates

Areas of significance requiring the use of management's judgments relate to the estimation of proved oil and gas reserves, the use of proved reserves in calculating depletion, depreciation, and amortization (DD&A), estimates of future net revenues in computing ceiling test limitations and estimates of future abandonment obligations used in recording asset retirement obligations, and the assessment of goodwill. Estimates and judgments are also required in determining allowance for bad debt, impairments of undeveloped properties and other assets, purchase price allocation, valuation of deferred tax assets, fair value measurements, and contingencies.

Accounts Receivable, Accounts Payable, and Accrued Liabilities

The components of our accounts receivable, accounts payable, and accrued liabilities are shown below:

(in thousands)	September 30, 2014	December 31, 2013
Receivables, net of allowance		
Trade	$ 95,243	$ 83,070
Oil and gas sales	314,005	265,050

Gas gathering, processing, and marketing	21,265	19,102
Other	189	532
Receivables, net	$ 430,702	$ 367,754
Accounts payable		
Trade	$ 82,440	$ 80,918
Gas gathering, processing, and marketing	40,948	35,192
Accounts payable	$ 123,388	$ 116,110
Accrued liabilities		
Exploration and development	$ 215,762	$ 173,298
Taxes other than income	30,012	27,509
Other	228,300	211,688
Accrued liabilities	$ 474,074	$ 412,495

Recently Issued Accounting Standards

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2014-09, Revenue from Contracts with Customers (Topic 606). The new revenue standard provides a five-step analysis of transactions to determine when and how revenue is recognized. The core principle of the guidance is that a company should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The guidance in this update supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance throughout the Industry Topics of the Codification. We must comply with this ASU beginning in fiscal year 2017 and early adoption is not permitted. Entities can choose to apply the standard using either the full retrospective approach or a modified retrospective approach. We are

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Notes to Consolidated Financial Statements (Continued)

September 30, 2014

(Unaudited)

currently evaluating the impact of the provisions of Topic 606 and the effects of adoption cannot be determined at this time.

2.Derivative Instruments/Hedging

We periodically use derivative instruments to mitigate our exposure to a decline in commodity prices and the corresponding negative impact on cash flow available for reinvestment. While the use of these instruments limits the downside risk of adverse price changes, their use may also limit future revenues from favorable price changes.

Depending on changes in oil and gas futures markets and management's view of underlying supply and demand trends, we may increase or decrease our hedging positions.

We have elected not to account for our derivatives as cash flow hedges. Therefore, we recognize settlements and changes in the assets or liabilities relating to our open derivative contracts in earnings. Cash settlements of our contracts are included in cash flows from operating activities in our statements of cash flows.

The following tables summarize our outstanding derivative contracts as of September 30, 2014:

Oil Contracts

Period	Type	Volume/Day	Index (1)	Weighted Average Price Floor	Ceiling	Fair Value (in thousands)
Oct 14 – Dec 14	Collars	12,000 Bbls	WTI	$ 85.00	$ 103.47	$ 1,089

(1) WTI refers to West Texas Intermediate price as quoted on the New York Mercantile Exchange.

Gas Contracts

Period	Type	Volume/Day	Index (1)	Weighted Average Price Floor	Ceiling	Fair Value (in thousands)
Oct 14 – Dec 14	Collars	80,000 MMBtu	PEPL	$ 3.51	$ 4.57	$ (81)
Oct 14 – Dec 14	Collars	60,000 MMBtu	Perm EP	$ 3.62	$ 4.50	$ (74)

(1) PEPL refers to Panhandle Eastern Pipe Line, Tex/OK Mid-Continent Index as quoted in Platt's Inside FERC. Perm EP refers to El Paso Natural Gas Company, Permian Basin Index as quoted in Platt's Inside FERC.

Under a collar agreement, we receive the difference between the published index price and a floor price if the index price is below the floor. We pay the difference between the ceiling price and the index price if the index price is above the contracted ceiling price. No amounts are paid or received if the index price is between the floor and ceiling prices.

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Notes to Consolidated Financial Statements (Continued)

September 30, 2014

(Unaudited)

The following table presents the net gains and (losses) from settlements and changes in fair value of our derivative contracts and the gains (losses) from settlements during the periods shown below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2014	2013	2014	2013
Gain (loss) on derivative instruments, net	$ 9,229	$ (10,824)	$ (8,960)	$ 1,233
Gain (loss) from settlement of derivative instruments	$ (211)	$ (6,097)	$ (6,015)	$ (4,332)

Our derivative contracts are carried at their fair value on our balance sheet using Level 2 inputs. We estimate the fair value with internal risk-adjusted discounted cash flow calculations. Cash flows are based on published forward commodity price curves for the underlying commodity as of the date of the estimate. For collars, we estimate the option value of the contract floors and ceilings using an option pricing model, which takes into account market volatility, market prices, and contract terms.

The fair value of our derivative instruments in an asset position includes a measure of counterparty credit risk and the fair value of instruments in a liability position includes a measure of our own non-performance risk. These credit risks are based on current published credit default swap rates.

Due to the volatility of commodity prices, the estimated fair value of our derivative instruments is subject to fluctuation from period to period, which could result in significant differences between the current estimated fair value and the ultimate settlement price.

Our derivative instruments are subject to enforceable master netting arrangements, which allow us to offset recognized asset and liability fair value amounts on contracts with the same counterparty. Our policy is to not offset asset and liability positions in our accompanying balance sheets.

The following table presents the amounts and classifications of our derivative assets and liabilities as of September 30, 2014 and December 31, 2013, as well as the potential effect of netting arrangements on contracts with the same counterparty.

September 30, 2014:

(in thousands)	Balance Sheet Location	Asset	Liability
Oil contracts	Current assets — Derivative instruments	$ 1,089	$ —
Natural gas contracts	Current assets — Derivative instruments	1	—
Natural gas contracts	Current liabilities — Derivative instruments	—	156
Total gross amounts presented in accompanying balance sheet		1,090	156
Less: gross amounts not offset in the accompanying balance sheet		(156)	(156)
Net amount:		$ 934	$ —

December 31, 2013:

(in thousands)	Balance Sheet Location	Asset	Liability
Oil contracts	Current assets — Derivative instruments	$ 1,805	$ —
Natural gas contracts	Current assets — Derivative instruments	2,463	—
Oil contracts	Current liabilities — Derivative instruments	—	389
Total gross amounts presented in accompanying balance sheet		4,268	389
Less: gross amounts not offset in the accompanying balance sheet		(389)	(389)
Net amount:		$ 3,879	$ —

We are exposed to financial risks associated with our derivative contracts from non-performance by our counterparties. We have mitigated our exposure to any single counterparty by contracting with a number of

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Notes to Consolidated Financial Statements (Continued)

September 30, 2014

(Unaudited)

financial institutions, each of which has a high credit rating and is a member of our bank credit facility. Our member banks do not require us to post collateral for our hedge liability positions. Because some of the member banks have discontinued hedging activities, in the future we may hedge with counterparties outside our bank group to obtain competitive terms and to spread counterparty risk.

3.Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The FASB has established a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. This hierarchy consists of three broad levels. Level 1 inputs are the highest priority and consist of unadjusted quoted prices in active markets for identical assets and liabilities. Level 2 are inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly. Level 3 are unobservable inputs for an asset or liability.

The following tables provide fair value measurement information for certain assets and liabilities as of September 30, 2014 and December 31, 2013:

September 30, 2014: (in thousands)	Carrying Amount	Fair Value
Financial Assets (Liabilities):		
5.875% Notes due 2022	$ (750,000)	$ (810,000)
4.375% Notes due 2024	$ (750,000)	$ (755,775)
Derivative instruments — assets	$ 1,090	$ 1,090

Derivative instruments — liabilities	$ (156)	$ (156)

December 31, 2013: (in thousands)	Carrying Amount	Fair Value
Financial Assets (Liabilities):		
Bank debt	$ (174,000)	$ (174,000)
5.875% Notes due 2022	$ (750,000)	$ (799,988)
Derivative instruments — assets	$ 4,268	$ 4,268
Derivative instruments — liabilities	$ (389)	$ (389)

Assessing the significance of a particular input to the fair value measurement requires judgment, including the consideration of factors specific to the asset or liability. The following methods and assumptions were used to estimate the fair value of the assets and liabilities in the table above.

Debt (Level 1)

The fair value of our bank debt at December 31, 2013 was estimated to approximate the carrying amount because the floating rate interest paid on such debt was set for periods of three months or less.

The fair value for our 4.375% and 5.875% fixed rate notes was based on their last traded value before period end.

Derivative Instruments (Level 2)

The fair value of our derivative instruments was estimated using internal discounted cash flow calculations. Cash flows are based on the stated contract prices and current and published forward commodity price

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

September 30, 2014

(Unaudited)

curves, adjusted for volatility. The cash flows are risk adjusted relative to non-performance for both our counterparties and our liability positions. Please see Note 2 for further information on the fair value of our derivative instruments.

Other Financial Instruments

The carrying amounts of our cash, cash equivalents, accounts receivable, accounts payable, and accrued liabilities approximate fair value because of the short-term maturities and/or liquid nature of these assets and liabilities.

Most of our accounts receivable balances are uncollateralized and result from transactions with other companies in the oil and gas industry. Concentration of customers may impact our overall credit risk because our customers may be similarly affected by changes in economic or other conditions within the industry.

We routinely assess the recoverability of all material accounts receivable to determine their collectability. We accrue a reserve to the allowance for doubtful accounts when it is probable that a receivable will not be collected and the amount of the reserve may be reasonably estimated. At September 30, 2014 and December 31, 2013, the allowance for doubtful accounts was $3.1 million and $6.0 million, respectively.

4.Capital Stock

Authorized capital stock consists of 200 million shares of common stock and 15 million shares of preferred stock. At September 30, 2014, there were no shares of preferred stock outstanding. A summary of our common stock activity for the nine months ended September 30, 2014 follows:

(in thousands)	
Issued and outstanding as of December 31, 2013	87,152
Issuance of restricted stock awards	160
Common stock reacquired and retired	(117)
Restricted stock forfeited and retired	(132)
Option exercises, net of cancellations	185
Issued and outstanding as of September 30, 2014	87,248

Dividends

In September 2014, the Board of Directors declared a cash dividend of $0.16 per share. The dividend is payable on December 1, 2014 to stockholders of record on November 14, 2014. Future dividend payments will depend on our level of earnings, financial requirements, and other factors considered relevant by the Board of Directors.

5.Stock-based Compensation

In May 2014, our 2014 Equity Incentive Plan (the 2014 Plan) was approved by stockholders and our previous plan was terminated at that time. Outstanding awards under the previous plan were not impacted. The primary purposes of the 2014 Plan are to increase the number of shares available in connection with awards, provide flexibility in the types of available awards and design of awards, modify certain individual award limits and revise the performance measures for qualified performance-based awards. The 2014 Plan provides for grants of stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, dividend equivalents and other stock-based awards. A total of 6.6 million shares of common stock may be issued under the 2014 Plan, including shares available from the previous plan.

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

September 30, 2014

(Unaudited)

We have recognized non-cash stock-based compensation cost as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2014	2013	2014	2013
Restricted stock	$ 5,825	$ 5,329	$ 18,255	$ 17,252
Stock options	847	940	2,402	2,355
	6,672	6,269	20,657	19,607
Less amounts capitalized to oil and gas properties	(3,069)	(2,922)	(9,782)	(9,148)
Compensation expense	$ 3,603	$ 3,347	$ 10,875	$ 10,459

Historical amounts may not be representative of future amounts as additional awards may be granted.

Restricted Stock and Units

The following tables provide information about restricted stock awards granted during the three and nine months ended September 30, 2014 and 2013.

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013

	Number of Shares	Weighted Average Grant-Date Fair Value	Number of Shares	Weighted Average Grant-Date Fair Value
Performance stock awards	—	$ —	26,000	$ 56.85
Service-based stock awards	146,750	$ 139.02	228,200	$ 72.83
Total restricted stock awards	146,750	$ 139.02	254,200	$ 71.20

	Nine Months Ended September 30, 2014		Nine Months Ended September 30, 2013	
	Number of Shares	Weighted Average Grant-Date Fair Value	Number of Shares	Weighted Average Grant-Date Fair Value
Performance stock awards	—	$ —	26,000	$ 56.85
Service-based stock awards	160,402	$ 138.02	277,236	$ 72.49
Total restricted stock awards	160,402	$ 138.02	303,236	$ 71.15

Performance awards have been granted to eligible executives and are subject to market condition-based vesting determined by our stock price performance relative to a defined peer group's stock price performance. After three years of continued service, an executive will be entitled to vest in 50% to 100% of the award. In accordance with Internal Revenue Code Section 162(m), certain of the amounts awarded may not be deductible for tax purposes. Service-based stock awards granted to other eligible employees and non-employee directors have vesting schedules of three to five years.

Compensation cost for the performance stock awards is based on the grant-date fair value of the award utilizing a Monte Carlo simulation model. Compensation cost for the service-based vesting restricted shares is

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based upon the grant-date market value of the award. Such costs are recognized ratably over the applicable vesting period.

The following table reflects the non-cash compensation cost related to our restricted stock:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2014	2013	2014	2013
Performance stock awards	$ 2,900	$ 2,710	$ 8,714	$ 7,963
Service-based stock awards	2,925	2,619	9,541	9,289
	5,825	5,329	18,255	17,252
Less amounts capitalized to oil and gas properties	(2,695)	(2,491)	(8,766)	(8,229)
Restricted stock compensation expense	$ 3,130	$ 2,838	$ 9,489	$ 9,023

Unrecognized compensation cost related to unvested restricted shares at September 30, 2014 was $64.1 million, which we expect to recognize over a weighted average period of approximately 2.3 years.

The following table provides information on restricted stock and unit activity as of September 30, 2014 and changes during the year. A restricted unit held by an employee represents a right to an unrestricted share of common stock upon completion of defined vesting and holding periods. A restricted unit held by a non-employee director represents an election to defer payment of director fees until the time specified by the director in his deferred compensation agreement. The remaining outstanding restricted units shown below represent restricted units held by a non-employee director who has elected to defer payment of common stock represented by the units until termination of his service on the Board of Directors.

	Restricted	Restricted

	Stock	Units
Outstanding as of January 1, 2014	1,863,834	8,838
Vested	(287,047)	N/A
Converted to stock	N/A	—
Granted	160,402	—
Canceled	(132,068)	—
Outstanding as of September 30, 2014	1,605,121	8,838
Vested included in outstanding	N/A	8,838

Stock Options

The following table provides information about stock options granted in 2014 and 2013:

	Three and Nine Months Ended September 30, 2014	Three and Nine Months Ended September 30, 2013
Options	82,500	144,400
Weighted average grant-date fair value	$ 41.69	$ 21.64
Weighted average exercise price	$ 139.02	$ 72.25

Options that have been granted under the 2014 plan and previous plans expire seven to ten years from the grant date and have service-based vesting schedules of three to five years. The exercise price for an option under the

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2014 plan is the closing price of our common stock as reported by the New York Stock Exchange on the date of grant. The previous plans provided that all grants have an exercise price of the average of the high and low prices of our common stock as reported by the New York Stock Exchange on the date of grant.

Compensation cost related to stock options is based on the grant-date fair value of the award, recognized ratably over the applicable vesting period. We estimate the fair value using the Black-Scholes option-pricing model. Expected volatilities are based on the historical volatility of our common stock. We also use historical data to estimate the probability of option exercise, expected years until exercise and potential forfeitures. We use U.S. Treasury bond rates in effect at the grant date for our risk-free interest rates.

Non-cash compensation cost related to our stock options is reflected in the following table:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	2014	2013	2014	2013
Stock option awards	$ 847	$ 940	$ 2,402	$ 2,355
Less amounts capitalized to oil and gas properties	(374)	(431)	(1,016)	(919)
Stock option compensation expense	$ 473	$ 509	$ 1,386	$ 1,436

As of September 30, 2014, there was $4.7 million of unrecognized compensation cost related to non-vested stock options. We expect to recognize that cost pro rata over a weighted-average period of approximately 2.0 years.

Information about outstanding stock options is summarized below:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Term	Aggregate Intrinsic Value (in thousands)
Outstanding as of January 1, 2014	531,016	$ 59.78		
Granted	82,500	$ 139.02		
Exercised	(185,258)	$ 56.83		
Forfeited	(17,509)	$ 71.39		
Outstanding as of September 30, 2014	410,749	$ 76.53	5.2 Years	$ 22,092
Exercisable as of September 30, 2014	204,926	$ 58.37	4.3 Years	$ 14,306

The following table provides information regarding the options exercised and the grant-date fair value of options vested:

	Nine months ended September 30,	
(dollars in thousands)	2014	2013
Number of options exercised	185,258	201,295
Cash received from option exercises	$ 10,529	$ 10,168
Intrinsic value of options exercised	$ 13,872	$ 6,811
Grant-date fair value of options vested	$ 4,419	$ 2,521

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The following table provides information on non-vested stock option activity as of September 30, 2014 and changes during the year:

	Options	Weighted Average Grant-Date Fair Value	Weighted Average Exercise Price
Non-vested as of January 1, 2014	343,014	$ 21.64	$ 63.81
Granted	82,500	$ 41.69	$ 139.02
Vested	(202,182)	$ 21.86	$ 62.48
Forfeited	(17,509)	$ 23.34	$ 71.39
Non-vested as of September 30, 2014	205,823	$ 29.32	$ 94.62

6.Asset Retirement Obligations

We recognize the fair value of liabilities for retirement obligations associated with tangible long-lived assets in the period in which there is a legal obligation associated with the retirement of such assets and the amount can be reasonably estimated. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. This liability includes costs related to the plugging and abandonment of wells, the removal of facilities and equipment, and site restorations. Subsequent to initial measurement, the asset retirement liability is required to be accreted each period. If the fair value of a recorded asset retirement obligation changes, a revision is recorded to both the asset retirement obligation and the asset retirement capitalized cost. Capitalized costs are included as a component of the DD&A calculations.

The following table reflects the components of the change in the carrying amount of the asset retirement obligation for the nine months ended September 30, 2014:

(in thousands)	
Asset retirement obligation at January 1, 2014	$ 154,026
Liabilities incurred	10,022
Liability settlements and disposals	(22,675)
Accretion expense	5,669
Revisions of estimated liabilities	23,286
Asset retirement obligation at September 30, 2014	170,328
Less current obligation	(16,387)
Long-term asset retirement obligation	$ 153,941

During the first nine months of 2014, the liability settlements and disposals included $11.1 million related to properties that were sold. Also during this period we recognized revisions of estimated liabilities totaling $23.3 million, which were due to changes in abandonment cost and timing estimates.

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7.Long-Term Debt

Debt at September 30, 2014 and December 31, 2013 consisted of the following:

(in thousands)	September 30, 2014	December 31, 2013
Bank debt	$ —	$ 174,000
5.875% Senior Notes due 2022	750,000	750,000
4.375% Senior Notes due 2024	750,000	—
Total long-term debt	$ 1,500,000	$ 924,000

Bank Debt

In May 2014, we amended our senior unsecured revolving credit facility (Credit Facility) to extend the maturity date two years to July 14, 2018 and lowered the margins applicable to loans and commitments. The amendment also raised our borrowing base from $2.25 billion to $2.5 billion until the next regular annual redetermination date scheduled for April 15, 2015. The borrowing base under the Credit Facility is determined at the discretion of the lenders based on the value of our proved reserves. Our aggregate commitments remained unchanged at $1 billion.

As of September 30, 2014, we had letters of credit outstanding under the Credit Facility of $2.5 million, leaving an unused borrowing availability of $997.5 million.

At our option, borrowings under the Credit Facility, as amended in May 2014, may bear interest at either (a) LIBOR plus 1.5-2.25%, based on our leverage ratio, or (b) the higher of (i) a prime rate, (ii) the federal funds effective rate plus 0.50%, or (iii) adjusted one-month LIBOR plus 1.0% plus, in each case, an additional 0.5-1.25%, based on our leverage ratio.

The Credit Facility also has financial covenants that include the maintenance of current assets (including unused bank commitments) to current liabilities of greater than 1.0. We also must maintain a leverage ratio of total debt to earnings before interest expense, income taxes and non-cash items (such as depreciation, depletion and amortization expense, unrealized gains and losses on commodity derivatives, ceiling test write-downs, and goodwill impairments) of not more than 3.5. Other covenants could limit our ability to incur additional indebtedness, pay dividends, repurchase our common stock, or sell assets. As of September 30, 2014, we were in compliance with all of the financial and non-financial covenants.

5.875% Notes due 2022

In April 2012, we issued $750 million of 5.875% senior notes due May 1, 2022, with interest payable semiannually in May and November. The notes were sold to the public at par. The notes are governed by an indenture containing certain covenants, events of default and other restrictive provisions. We may redeem the notes in whole or in part, at any time on or after May 1, 2017, at redemption prices of 102.938% of the principal amount as of May 1, 2017, declining to 100% on May 1, 2020 and thereafter.

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(Unaudited)

4.375% Notes due 2024

In June 2014, we issued $750 million of 4.375% senior notes due June 1, 2024, with interest payable semiannually in June and December. The notes were sold to the public at par. The notes are governed by an indenture containing certain covenants, events of default and other restrictive provisions. At any time prior to March 1, 2024, we may redeem all or a part of the notes at a defined make-whole redemption price calculated at the time of redemption. At any time on or after March 1, 2024, we may redeem all or part of the notes at a price equal to 100% of the principal amount.

8.Income Taxes

The components of our provision for income taxes are as follows:

	Three months ended September 30,		Nine months ended September 30,	
(in thousands)	2014	2013	2014	2013
Current benefit	$ —	$ —	$ —	$ —
Deferred taxes	84,707	81,823	254,210	211,615
	$ 84,707	$ 81,823	$ 254,210	$ 211,615
Combined Federal and State effective income tax rate	37.0 %	37.2 %	37.1 %	37.2 %

At December 31, 2013, we had a U.S. net tax operating loss carryforward of approximately $605.4 million, which would expire in tax years 2031 through 2033. We believe that the carryforward will be utilized before it expires. The amount of U.S. net tax operating loss carryforward that will be recorded to equity when utilized to reduce taxes payable is $56.4 million. We also had an alternative minimum tax credit carryforward of approximately $4.1 million.

At September 30, 2014, we had no unrecognized tax benefits that would impact our effective tax rate and have made no provisions for interest or penalties related to uncertain tax positions. The tax years 2011 through 2013 remain open to examination by the Internal Revenue Service of the United States. We file tax returns with various state taxing authorities, which remain open to examination for the 2010 through 2013 tax years.

Our provision for income taxes differed from the U.S. statutory rate of 35% primarily due to state income taxes and non-deductible expenses.

9.Supplemental Disclosure of Cash Flow Information

	Three months ended September 30,		Nine months ended September 30,	
(in thousands)	2014	2013	2014	2013
Cash paid during the period for:				
Interest expense (including capitalized amounts)	$ 835	$ 1,932	$ 27,125	$ 27,158
Interest capitalized	$ 30	$ 394	$ 13,587	$ 15,706
Income taxes	$ —	$ —	$ 354	$ 205
Cash received for income taxes	$ —	$ 213	$ 342	$ 450

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Notes to Consolidated Financial Statements (Continued)

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10.Earnings per Share

The calculations of basic and diluted net earnings per common share under the two-class method are presented below:

	Three months ended September 30,		Nine months ended September 30,	
(in thousands, except per share data)	2014	2013	2014	2013
Basic:				
Net income	$ 144,315	$ 138,370	$ 431,412	$ 357,862
Participating securities' share in earnings	(2,411)	(2,375)	(7,206)	(6,049)
Net income applicable to common stockholders	$ 141,904	$ 135,995	$ 424,206	$ 351,813
Diluted:				
Net income	$ 144,315	$ 138,370	$ 431,412	$ 357,862
Participating securities' share in earnings	(2,407)	(2,371)	(7,194)	(6,041)
Net income applicable to common stockholders	$ 141,908	$ 135,999	$ 424,218	$ 351,821
Shares:				
Basic shares outstanding	85,643	85,213	85,643	85,213
Incremental shares from assumed exercise of stock options	136	134	145	117
Fully diluted common stock	85,779	85,347	85,788	85,330
Excluded (1)	83	232	87	254
Earnings per share to common stockholders (2):				
Basic	$ 1.65	$ 1.59	$ 4.94	$ 4.12
Diluted	$ 1.65	$ 1.59	$ 4.94	$ 4.12

(1) Inclusion of certain outstanding stock options would have an anti-dilutive effect.

(2) Earnings per share are based on actual figures rather than the rounded figures presented.

11.Commitments and Contingencies

Commitments

We have commitments of $212.8 million to finish drilling and completing wells in progress at September 30, 2014. We also have various commitments for drilling rigs. The total minimum expenditure commitments under these agreements are $53.7 million.

In New Mexico and Texas, we are constructing gathering facilities and pipelines. At September 30, 2014, we had commitments of $5.9 million relating to these construction projects.

At September 30, 2014, we had firm sales contracts to deliver approximately 45.2 Bcf of natural gas over the next 15 months. If this gas is not delivered, our financial commitment would be approximately $166.6 million. This commitment will fluctuate due to price volatility and actual volumes delivered. However, we believe no financial commitment will be due based on our current proved reserves and production levels from which we can fulfill these obligations.

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We have various other transportation and delivery commitments in the normal course of business, which approximate $1.2 million over the next two years.

We have various commitments for office space and equipment under operating lease arrangements totaling $126.0 million for the next five years and beyond.

All of the noted commitments were routine and were made in the ordinary course of our business.

Litigation

In the ordinary course of business, we have various litigation matters. We assess the probability of estimable amounts related to litigation matters in accordance with guidance established by the FASB and adjust our accruals accordingly. Though some of the related claims may be significant, we believe the resolution of them, individually or in the aggregate, would not have a material adverse effect on our financial condition or results of operations after consideration of current accruals.

H.B. Krug, et al versus H&P

In the H.B. Krug, et al. v. Helmerich & Payne, Inc. (H&P) case, on December 13, 2013 the Oklahoma Supreme Court reversed the Tulsa County District Court's original judgment of $119.6 million and affirmed an alternative jury verdict for $3.65 million. It also remanded the case back to the trial court for consideration of potential prejudgment interest, attorney's fees and cost awards. Accordingly, on December 31, 2013 we reduced the previously recognized litigation expense and the associated long-term liability by $142.8 million.

On April 1, 2014, Cimarex paid the Plaintiffs $15.8 million in satisfaction of the $3.65 million damages award, the post-judgment interest award and the payment in lieu of bond, all of which are now final and not appealable. On June 24, 2014, the trial court ruled the Plaintiffs were not entitled to prejudgment interest but were entitled to attorney's fees and costs, the amount of which will be determined at a subsequent hearing. On July 31, 2014, the Plaintiffs appealed the trial court's denial of prejudgment interest, which will be determined by the Oklahoma Supreme Court. The outcome of these remaining issues cannot be determined, and our current estimates and assessments likely will change, as a result of these future legal proceedings.

12.Property Acquisitions and Sales

The following acquisitions and sales were made in the ordinary course of business.

During the first nine months of 2014, we made property acquisitions totaling $259.2 million, most of which were in our Cana-Woodford shale play in Western Oklahoma. During the same period of 2013, we had property acquisitions of $6.2 million.

We sold interests in various non-core oil and gas properties for $447.5 million during the first nine months of 2014. Most of the proceeds were related to sales of producing gas wells in southwestern Kansas and undeveloped acreage in Reagan County, Texas. In the first nine months of 2013, we sold interests in non-core oil and gas properties for $37.7 million. During the second quarter of 2013, we also sold a 50% interest in our Culberson County, Texas Triple Crown gas gathering and processing system for approximately $31 million.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

Cimarex is an independent oil and gas exploration and production company. Our operations are entirely located in the United States, mainly in Oklahoma, Texas and New Mexico.

Our principal business objective is to profitably grow proved reserves and production for the long-term benefit of our stockholders through a diversified drilling portfolio. Our strategy centers on maximizing cash flow from producing properties and profitably reinvesting that cash flow in exploration and development. We occasionally consider property acquisitions and mergers to enhance our competitive position.

In order to achieve a consistent rate of growth and mitigate risk, we have historically maintained a portfolio of exploration and development projects targeting both oil and gas. We seek geologic and geographic diversification by operating in multiple basins. In recent years, we have shifted our capital expenditures to oil and liquids-rich gas projects because of strong oil prices relative to gas prices. We deal with volatility in commodity prices by maintaining flexibility in our capital investment program.

Our operations are currently focused in two main areas: the Permian Basin and the Mid-Continent region. The Permian Basin region encompasses west Texas and southeast New Mexico. The Mid-Continent region consists of Oklahoma and the Texas Panhandle.

Growth is generally funded with cash flow provided by operating activities together with bank borrowings, sales of non-strategic assets and occasional public financing. Conservative use of leverage and maintaining a strong balance sheet have long been part of our financial strategy. We have a long track record of profitable growth.

Third quarter 2014 summary of operating and financial results:

- Total average daily production grew 31% to 942.4 MMcfe/d.
- Oil production grew 10%, gas production was up by 35% and NGL volumes increased by 59%.
- Oil, gas and NGL sales totaled $636.5 million, 16% higher than a year earlier.
- Net income was $144.3 million ($1.65 per diluted share) versus $138.4 million ($1.59 per diluted share) a year ago.

- Exploration and development expenditures for the quarter totaled $459.6 million.
- Cash flow provided by operating activities during the first nine months of 2014 increased 35% to $1.272 billion compared to $940.7 million for the same period of 2013.
- Total debt at September 30, 2014 was $1.5 billion.

Revenues

Almost all of our revenues are derived from the sales of oil, gas and NGL production. Increases or decreases in our revenue, profitability and future production growth are highly dependent on the commodity prices we receive. Prices we receive are determined by prevailing market conditions. Regional and worldwide economic and geopolitical activity, weather and other factors influence market conditions, which often result in significant volatility in commodity prices.

Oil sales contributed 56% of our total production revenue for the first nine months of 2014. Gas sales accounted for 28% and NGL sales were 16%. A $1.00 per barrel change in our realized oil price would have resulted in an $11.3 million change in revenues. A $0.10 per Mcf change in our realized gas price would have resulted in an $11.2 million change in our gas revenues. A $1.00 per barrel change in NGL prices would have changed revenues by $8.2 million.

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The following table presents our average realized commodity prices and major U.S. index prices. Our average realized prices do not include settlements of commodity derivative contracts.

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Oil Prices:				
Average realized sales price ($/Bbl)	$ 87.27	$ 102.88	$ 90.87	$ 93.81
Average WTI Midland price ($/Bbl)	$ 86.93	$ 105.47	$ 91.64	$ 96.96
Average WTI Cushing price ($/Bbl)	$ 97.15	$ 105.81	$ 99.61	$ 98.14
Gas Prices:				
Average realized sales price ($/Mcf)	$ 4.10	$ 3.72	$ 4.62	$ 3.73
Average Henry Hub price ($/Mcf)	$ 4.07	$ 3.58	$ 4.57	$ 3.67
NGL Prices:				
Average realized sales price ($/Bbl)	$ 34.08	$ 28.63	$ 36.10	$ 28.57

Approximately 80% of our oil production is in the Permian Basin, the sale of which is tied to the WTI Midland benchmark price. Due to greater industry-wide production in the area, related oil prices have declined relative to WTI Cushing benchmark prices. In the third quarter of 2014, the average Midland index price was $10.22 per barrel lower than the average Cushing index price. In the third quarter of 2013, the average Midland price was only $0.34 per barrel lower than the average Cushing prices. The average Midland index price was lower than the Cushing price for the first nine months of 2014 by $7.97 per barrel versus $1.18 lower for the same period of 2013. The declines in the Midland benchmark prices resulted in our lower realized oil prices in 2014.

Prior to 2014, our average realized prices for gas and NGLs were net of certain processing fees. Beginning in 2014, these fees are no longer included in realized prices. The resulting positive impact on gas prices for the three and nine months ended September 30, 2014 was $0.07 per Mcf and $0.08 per Mcf, respectively. The positive impact on NGL prices was $3.43 per Bbl and $3.60 per Bbl for the three and nine months ended September 30, 2014, respectively. These positive impacts to prices were offset by increased transportation, processing and other operating costs. (See Results of Operations below and Note 1, Basis of Presentation – Oil, Gas and NGL Sales, to the Consolidated Financial Statements in this report for additional information regarding these processing fees.)

The impact of changes in realized prices is discussed below under RESULTS OF OPERATIONS.

Production and other operating expenses

Costs associated with producing oil and gas are substantial. Some of these costs vary with commodity prices, some trend with the type and volume of production and some are a function of the number of wells we own.

Production expense generally consists of costs for labor, equipment, maintenance, salt water disposal, compression, power, treating and miscellaneous other items. Production expense also includes well workover activity necessary to maintain production from existing wells.

Transportation, processing and other operating costs principally consists of expenditures to prepare and transport production from the wellhead to a specified sales point and gas processing costs. These costs vary by region and will fluctuate with increases or decreases in production volumes and changes in fuel and compression costs.

Depreciation, depletion and amortization (DD&A) of our producing properties is computed using the units-of-production method. The economic life of each producing well depends upon the estimated proved reserves for that well, which in turn depend upon the assumed realized sales price for future production. Therefore, fluctuations in oil and gas prices will impact the level of proved reserves used in the calculation. Higher prices generally have

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the effect of increasing reserves, which reduces depletion expense. Conversely, lower prices generally have the effect of decreasing reserves, which increases depletion expense. The cost of replacing production also impacts our DD&A rate. In addition, changes in estimates of reserve quantities, estimates of operating and future development costs, and reclassifications of properties from unproved to proved will impact depletion expense.

We use the full cost method of accounting for our oil and gas properties. Accounting rules require us to perform a quarterly ceiling test calculation to test our oil and gas properties for possible impairment. The primary components impacting this analysis are commodity prices, reserve quantities added and produced, overall exploration and development costs, depletion expense, and tax effects. If the net capitalized cost of our oil and gas properties subject to amortization (the carrying value) exceeds the ceiling limitation, the excess would be expensed. The ceiling limitation is equal to the sum of (a) the present value discounted at 10% of estimated future net cash flows from proved reserves, (b) the cost of properties not being amortized, (c) the lower of cost or estimated fair value of unproven properties included in the costs being amortized, and (d) all related tax effects.

At September 30, 2014, the calculated value of the ceiling limitation exceeded the carrying value of our oil and gas properties subject to the test, and no impairment was necessary. However, a decline of 9% in the value of the ceiling limitation would have resulted in an impairment. If pricing conditions decline, or if there is a negative impact on one or more of the other components of the calculation, we may incur a full cost ceiling impairment related to our oil and gas properties in future quarters. An impairment charge would have no effect on liquidity or our capital resources, but it could adversely affect our results of operations in the period incurred.

General and administrative (G&A) expenses consist primarily of salaries and related benefits, office rent, legal fees, consultants, systems costs and other administrative costs incurred in our offices and not directly associated with exploration, development or production activities. Our G&A expense is reported net of amounts reimbursed to us by working interest owners of the oil and gas properties we operate and net of amounts capitalized pursuant to the full cost method of accounting.

Since 2009, we have chosen not to apply hedge accounting treatment to our derivative instruments. As a result, any settlements on the contracts are included as a component of operating costs and expenses as either a net gain or loss on derivative instruments.

RESULTS OF OPERATIONS

Three Months and Nine Months Ended September 30, 2014 vs. September 30, 2013

Net income for the third quarter of 2014 was $144.3 million ($1.65 per diluted share), up 4% from $138.4 million ($1.59 per diluted share) for the same period of 2013. For the first nine months of 2014, net income of $431.4 million ($4.94 per diluted share) was 21% greater than net income of $357.9 million ($4.12 per diluted share) for the same period of 2013. The increases in net income for the 2014 periods resulted from increased production volumes and higher realized prices for natural gas and NGLs, which were partially offset by higher operating expenses and income taxes compared to the 2013 periods. These changes are discussed further in the analysis that follows.

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Production Revenue (in thousands or as indicated)	2014	2013	Percent Change Between 2014 / 2013	Price/Volume Change Price	Volume	Total
For the Three Months Ended September 30,						
Oil sales	$ 348,276	$ 371,881	(6) %	$ (62,300)	$ 38,695	$ (23,605)
Gas sales	176,539	118,824	49 %	16,376	41,339	57,715
NGL sales	111,701	58,922	90 %	17,865	34,914	52,779
	$ 636,516	$ 549,627	16 %	$ (28,059)	$ 114,948	$ 86,889
For the Nine Months Ended September 30,						
Oil sales	$ 1,028,229	$ 933,879	10 %	$ (33,269)	$ 127,619	$ 94,350
Gas sales	519,139	346,492	50 %	100,023	72,624	172,647
NGL sales	297,128	168,106	77 %	61,979	67,043	129,022
	$ 1,844,496	$ 1,448,477	27 %	$ 128,733	$ 267,286	$ 396,019

	For the Three Months Ended September 30, 2014	2013	Percent Change Between 2014 / 2013	For the Nine Months Ended September 30, 2014	2013	Percent Change Between 2014 / 2013
Total oil volume — thousand barrels	3,991	3,615	10 %	11,316	9,955	14 %
Oil volume — barrels per day	43,376	39,292	10 %	41,450	36,464	14 %
Average oil price — per barrel	$ 87.27	$ 102.88	(15) %	$ 90.87	$ 93.81	(3) %
Total gas volume — MMcf	43,094	31,908	35 %	112,385	92,914	21 %
Gas volume — MMcf per day	468.4	346.8	35 %	411.7	340.3	21 %
Average gas price — per Mcf	$ 4.10	$ 3.72	10 %	$ 4.62	$ 3.73	24 %
Total NGL volume — thousand barrels	3,278	2,058	59 %	8,231	5,883	40 %
NGL volume — barrels per day	35,627	22,373	59 %	30,151	21,550	40 %
Average NGL price — per barrel	$ 34.08	$ 28.63	19 %	$ 36.10	$ 28.57	26 %

Total equivalent production volumes — MMcfe per day	942.4	716.8	31 %	841.3	688.4	22 %

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	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
Oil (Bbls per day)				
Permian Basin	34,299	31,993	33,090	29,343
Mid-Continent	8,158	5,801	7,166	5,944
Other	919	1,498	1,194	1,177
	43,376	39,292	41,450	36,464
Gas (MMcf per day)				
Permian Basin	126.6	102.5	117.6	93.9
Mid-Continent	333.3	230.2	284.9	232.6
Other	8.5	14.1	9.2	13.8
	468.4	346.8	411.7	340.3
NGL (Bbls per day)				
Permian Basin	12,634	9,575	11,144	7,643
Mid-Continent	22,604	12,090	18,475	13,129
Other	389	708	532	778
	35,627	22,373	30,151	21,550
Total Equivalent (MMcfe per day)				
Permian Basin	408.1	352.0	383.0	315.9
Mid-Continent	517.9	337.6	438.8	347.0
Other	16.4	27.2	19.5	25.5
	942.4	716.8	841.3	688.4

Third quarter 2014 production revenue increased 16% to $636.5 million compared to $549.6 million for the same quarter of last year. For the first nine months of 2014, revenue from our production totaled $1.844 billion, up 27% from $1.448 billion for the same period of 2013. Increased production volumes together with higher realized prices for natural gas and NGLs resulted in the year-over-year improvements.

Third quarter 2014 aggregate production volumes averaged 942.4 MMcfe/d, up 31% from 716.8 MMcfe/d for the third quarter of 2013. Average production volumes for the first nine months of 2014 were 841.3 MMcfe/d, up 22% from 688.4 MMcfe/d for the comparable 2013 period. Ongoing development drilling and workover activity in our Mid-Continent and Permian Basin core areas drove production volume growth.

Oil production for the third quarter of 2014 averaged 43,376 Bbl/d, up 10% from 39,292 Bbl/d in 2013. The growth in 2014 volume provided an additional $38.7 million of oil revenue. During the first nine months of 2014, our oil production averaged 41,450 Bbl/d, up from 36,464 Bbl/d in the 2013 period. The 14% increase contributed $127.6 million of additional revenue during the first nine months of 2014. Our Permian Basin and Mid-Continent regions contributed equally to the increases in 2014 production.

Third quarter 2014 gas production averaged 468.4 MMcf/d, compared to 346.8 MMcf/d in 2013. The 35% year-over-year increase resulted in additional revenue of $41.3 million. During the first nine months of 2014 our gas production averaged 411.7 MMcf/d, up 21% from the first nine months of 2013 average of 340.3 MMcf/d. The increase in gas production accounted for $72.6 million of additional revenue for the first nine months of 2014. Most of the increases in 2014 gas production came from the Cana-Woodford area of the Mid-Continent region.

Third quarter 2014 NGL production volumes averaged 35,627 Bbl/d and were 59% greater than 22,373 Bbl/d for 2013. The increase contributed $34.9 million of additional revenue and accounted for approximately two-thirds of the overall 90% increase in quarter-over-quarter NGL revenue. Approximately 80% of the volume increase resulted from our liquids-rich Cana-Woodford development program in the Mid-Continent region.

Our NGL production for the first nine months of 2014 averaged 30,151 Bbl/d, compared to 21,550 barrels per day in the 2013 period. This 40% increase in production provided an additional $67.1 million of revenue and

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accounted for about half of the aggregate year-over-year increase in NGL revenue. Increased volumes from our liquids-rich Cana-Woodford development program accounted for approximately 60% of the increase with the remainder coming from the Permian Basin.

Realized oil prices during the third quarter of 2014 averaged $87.27 per barrel, a decrease of 15% from $102.88 per barrel received in the same period of 2013. The lower third quarter 2014 price resulted in lower oil revenues of $62.3 million. For the first nine months of 2014, our average realized oil price was $90.87 per barrel, which was 3% lower than the average price of $93.81 for the same period of 2013. The decrease in price accounted for $33.3 million of lower oil revenue for the first nine months of 2014. Approximately 80% of our oil production comes from the Permian Basin, which is tied to WTI Midland benchmark prices. During 2014, the Midland benchmark prices have declined compared to those of 2013. See Revenues above for a comparison of realized prices to average benchmark prices.

Our average realized gas price for the third quarter of 2014 improved by 10% to $4.10 per Mcf, compared to $3.72 per Mcf in 2013. The 2014 price increase provided additional revenue of $16.4 million. Our average realized gas price of $4.62 per Mcf for the first nine months of 2014 was 24% higher than an average realized price of $3.73 for the same period of 2013 and increased gas revenues by $100.0 million. As noted above under Revenues, beginning in 2014, our average realized price for gas no longer includes deductions for certain processing fees, thus positively impacting revenue by $2.9 million ($0.07 per Mcf) for the third quarter of 2014 and by $8.6 million ($0.08 per Mcf) for the first nine months of 2014. These positive impacts to prices were offset by increased transportation, processing and other operating costs discussed below and in Note 1, Basis of Presentation – Oil, Gas and NGL Sales, to the Consolidated Financial Statements in this report.

Our third quarter 2014 realized NGL price averaged $34.08 per barrel, which was 19% higher than the average realized price of $28.63 per barrel in the 2013 period. The higher price in the third quarter of 2014 accounted for additional revenues of $17.9 million. In the first nine months of 2014, we received an average NGL price of $36.10 per barrel, which was 26% higher than the 2013 average realized price of $28.57 and resulted in $62.0 million of additional NGL revenue. As noted above under Revenues, beginning in 2014, our realized price for NGLs no longer includes deductions for certain processing fees, thus positively impacting revenue by $11.2 million ($3.43 per barrel) for the third quarter of 2014 and by $29.7 million ($3.60 per barrel) for the first nine months of 2014. These positive impacts to prices were offset by increased transportation, processing and other operating costs discussed below and in Note 1, Basis of Presentation – Oil, Gas and NGL Sales, to the Consolidated Financial Statements in this report.

We sometimes transport, process and market third-party gas that is associated with our equity gas. The table below reflects our pre-tax operating margin (revenues less direct expenses) for third-party gas gathering and processing as well as the marketing margin (revenues less purchases) for marketing third-party gas.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
Gas Gathering and Marketing (in thousands):				
Gas gathering and other revenues	$ 12,951	$ 11,380	$ 39,699	$ 32,951
Gas gathering and other costs	(8,588)	(6,970)	(27,413)	(18,310)
Gas gathering and other margin	$ 4,363	$ 4,410	$ 12,286	$ 14,641
Gas marketing revenues, net of related costs	$ 273	$ 329	$ 1,430	$ 21

Fluctuations in net margins from gas gathering and gas marketing activities are a function of increases and decreases in volumes, prices and costs associated with third-party gas.

In the third quarter of 2014, our total operating costs and expenses (not including gas gathering and marketing costs, or income tax expense) were $412.4 million, up 25% compared to $329.8 million in the same period of 2013. For the first nine months of 2014, operating costs were $1.169 billion, an increase of 31% over $889.9 million for the same period of 2013. Analyses of the year-over-year differences are discussed below.

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	For the Three Months Ended September 30,		Variance Between	Per Mcfe	
	2014	2013	2014 / 2013	2014	2013
Operating costs and expenses (in thousands, except per Mcfe):					
Depreciation, depletion and amortization	$ 219,359	$ 159,182	$ 60,177	$ 2.53	$ 2.41
Asset retirement obligation	1,420	1,797	(377)	$ 0.02	$ 0.03
Production	89,084	76,166	12,918	$ 1.03	$ 1.16
Transportation, processing and other operating	54,573	25,838	28,735	$ 0.63	$ 0.39
Taxes other than income	33,510	31,104	2,406	$ 0.39	$ 0.47
General and administrative	20,240	19,003	1,237	$ 0.23	$ 0.29
Stock compensation	3,603	3,347	256	$ 0.04	$ 0.05
(Gain) loss on derivative instruments, net	(9,229)	10,824	(20,053)	N/A	N/A
Other operating, net	(181)	2,507	(2,688)	N/A	N/A
	$ 412,379	$ 329,768	$ 82,611		

	For the Nine Months Ended September 30,		Variance Between	Per Mcfe	
	2014	2013	2014 / 2013	2014	2013
Operating costs and expenses (in thousands, except per Mcfe):					
Depreciation, depletion and amortization	$ 588,279	$ 442,851	$ 145,428	$ 2.56	$ 2.36
Asset retirement obligation	8,288	7,080	1,208	$ 0.04	$ 0.04
Production	250,310	214,985	35,325	$ 1.09	$ 1.15
Transportation, processing and other operating	145,299	66,494	78,805	$ 0.63	$ 0.35
Taxes other than income	99,454	84,039	15,415	$ 0.43	$ 0.45
General and administrative	57,523	57,416	107	$ 0.25	$ 0.31
Stock compensation	10,875	10,459	416	$ 0.05	$ 0.06
(Gain) loss on derivative instruments, net	8,960	(1,233)	10,193	N/A	N/A
Other operating, net	34	7,804	(7,770)	N/A	N/A
	$ 1,169,022	$ 889,895	$ 279,127		

Our third quarter 2014 DD&A expense of $219.4 million was 38% higher than the same period of 2013 and accounted for 73% of the total quarter-over-quarter increase in costs and expenses. On a unit of production basis, third-quarter 2014 DD&A increased by 5% to $2.53 per Mcfe. During the first nine months of 2014, DD&A expense increased 33% to $588.3 million and comprised 52% of the aggregate year-over-year increase in total costs and expenses. DD&A per Mcfe for the first nine months of 2014 increased by $0.20 (8%) to $2.56 per Mcfe.

Increases in our 2014 year-over-year production volumes were responsible for about 81% of our third quarter increase in DD&A expense and approximately 63% of the increase for the first nine months. The remainder of the period-over-period increases in DD&A were due to increases in our DD&A rates. Our DD&A rates have increased primarily because the cost of adding new proved reserves has exceeded the net remaining book basis of proved reserves added in prior years.

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Production costs consist of lease operating expense and workover expense as follows:

	For the Three Months Ended September 30,		Variance Between 2014 /	Per Mcfe	
(in thousands, except per Mcfe)	2014	2013	2013	2014	2013
Lease operating expense	$ 71,133	$ 60,364	$ 10,769	$ 0.82	$ 0.92
Workover expense	17,951	15,802	2,149	$ 0.21	$ 0.24
	$ 89,084	$ 76,166	$ 12,918	$ 1.03	$ 1.16

	For the Nine Months Ended September 30,		Variance Between 2014 /	Per Mcfe	
(in thousands, except per Mcfe)	2014	2013	2013	2014	2013
Lease operating expense	$ 204,379	$ 166,995	$ 37,384	$ 0.89	$ 0.89
Workover expense	45,931	47,990	(2,059)	$ 0.20	$ 0.26
	$ 250,310	$ 214,985	$ 35,325	$ 1.09	$ 1.15

Third quarter 2014 lease operating expense (LOE) of $71.1 million increased 18% compared to $60.4 million in 2013. LOE for the first nine months of 2014 increased by 22% to $204.4 million compared to $167.0 for the same period of 2013. As we continue to put new wells on production, we have experienced higher costs for salt water disposal, rental equipment, chemical treating, labor and electricity. We have also experienced increased costs for site maintenance and road repairs.

Workover expense for the third quarter of 2014 was 14% higher than the same period of 2013. During the first nine months of 2014, workover expense declined by 4% compared to 2013. Workover costs will fluctuate based on the amount of maintenance and remedial activity planned and/or required during the period.

Transportation, processing and other operating costs in the third quarter and first nine months of 2014 increased significantly compared to the same periods of 2013. These costs will vary by product type and region. Increases or decreases in sales and processing volumes, contractual fees, compression charges and fuel costs will have an impact on the overall costs. During the 2014 periods, about half of the increases in period-over-period costs resulted from greater production volumes, higher contractual fees and increases in fuel costs. The remaining increases relate to the inclusion of certain processing fees which in previous periods were treated as a reduction in realized sales prices for residue gas and NGLs. These costs accounted for approximately $0.17 per Mcfe for each of the 2014 periods. See Note 1, Basis of Presentation – Oil, Gas and NGL Sales, to the Consolidated Financial Statements of this report for additional information.

Taxes other than income are assessed by state and local taxing authorities on production, revenues or the value of properties. Revenue based production/severance taxes are our largest component of these taxes. During the third quarter and first nine months of 2014, these taxes increased by 8% and 18%, respectively, compared to the same periods of 2013. The increases are primarily due to increased production/severance taxes on higher production volumes and higher realized gas and NGL prices.

General and administrative (G&A) costs were as follows:

	For the Three Months Ended September 30,		Variance Between 2014 /	For the Nine Months Ended September 30,		Variance Between 2014 /
(in thousands)	2014	2013	2013	2014	2013	2013
G&A capitalized to oil & gas properties	$ 19,838	$ 19,836	$ 2	$ 62,278	$ 57,530	$ 4,748
G&A expense	20,240	19,003	1,237	57,523	57,416	107
	$ 40,078	$ 38,839	$ 1,239	$ 119,801	$ 114,946	$ 4,855
G&A expense per Mcfe	$ 0.23	$ 0.29	$ (0.06)	$ 0.25	$ 0.31	$ (0.06)

Our aggregate G&A for the third quarter and first nine months of 2014 increased modestly compared to the same periods of 2013. The increases resulted primarily from higher salaries and benefits related to additional employees.

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Stock compensation expense consists of non-cash charges resulting from the issuance of restricted stock and stock option awards, net of amounts capitalized. We have recognized non-cash stock-based compensation cost as follows:

(in thousands)	For the Three Months Ended September 30, 2014	2013	Variance Between 2014 / 2013	For the Nine Months Ended September 30, 2014	2013	Variance Between 2014 / 2013
Performance stock awards	$ 2,900	$ 2,710	$ 190	$ 8,714	$ 7,963	$ 751
Service-based stock awards	2,925	2,619	306	9,541	9,289	252
Restricted stock awards	5,825	5,329	496	18,255	17,252	1,003
Stock option awards	847	940	(93)	2,402	2,355	47
Total stock compensation	6,672	6,269	403	20,657	19,607	1,050
Less amounts capitalized to oil & gas properties	(3,069)	(2,922)	(147)	(9,782)	(9,148)	(634)
Stock compensation	$ 3,603	$ 3,347	$ 256	$ 10,875	$ 10,459	$ 416

Expense associated with stock compensation will fluctuate based on the grant-date market value of the award and the number of awards granted. See Note 5 to the Consolidated Financial Statements for further discussion regarding our stock-based compensation.

Net gains and losses on our derivative instruments are a function of fluctuations in the underlying commodity prices and the monthly settlement of the contracts. See Note 2 to the Consolidated Financial Statements in this report for further details regarding our derivative instruments.

The following table summarizes the net (gains) and losses from settlements and changes in fair value of our derivative contracts.

For the Three Months	For the Nine Months

(in thousands)	Ended September 30, 2014	2013	Ended September 30, 2014	2013
(Gain) loss on derivative instruments, net:				
Natural gas contracts	$ (2,377)	$ (376)	$ 7,443	$ (9,575)
Oil contracts	(6,852)	11,200	1,517	8,342
(Gain) loss on derivative instruments, net	$ (9,229)	$ 10,824	$ 8,960	$ (1,233)
Settlement (gains) losses:				
Natural gas contracts	$ —	$ (1,189)	$ 4,824	$ (1,189)
Oil contracts	211	7,286	1,191	5,521
Settlement (gains) losses	$ 211	$ 6,097	$ 6,015	$ 4,332

The caption "Other operating, net" includes costs and accruals related to various legal matters. As the result of certain litigation settlements these expenses have decreased considerably in 2014 versus comparable periods of 2013. See Note 11 to the Consolidated Financial Statements and Part II, Item 1, in this report for further information regarding legal proceedings.

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Other (income) and expense

(in thousands)	For the Three Months Ended September 30, 2014	2013	Variance Between 2014 / 2013	For the Nine Months Ended September 30, 2014	2013	Variance Between 2014 / 2013
Interest expense	$ 20,879	$ 13,954	$ 6,925	$ 51,645	$ 41,272	$ 10,373
Capitalized interest	(10,005)	(7,286)	(2,719)	(25,870)	(23,868)	(2,002)
Other, net	(11,123)	(2,263)	(8,860)	(22,207)	(13,637)	(8,570)
	$ (249)	$ 4,405	$ (4,654)	$ 3,568	$ 3,767	$ (199)

Interest expense includes interest on debt and amortization of financing costs. Our third quarter 2014 interest expense increased 50% compared to the third quarter of 2013. Interest expense for the first nine months of 2014 was 25% higher than the same period of 2013. The year-over-year increases were primarily the result of having more debt.

We capitalize interest on non-producing leasehold costs, the costs of drilling and completing wells and constructing qualified assets. Period-over-period costs will fluctuate based on the current rate of interest and the amount of costs on which interest is calculated. Capitalized interest in the 2014 periods increased compared to the comparable 2013 periods due to higher amounts of qualifying capitalized expenditures in the 2014 periods.

Components of “other, net” consist of miscellaneous income and expense items that will vary from period to period, including gain or loss on the sale or value of oil and gas well equipment and supplies, income and expense associated with other non-operating activities, miscellaneous asset sales and interest income. Increases in other, net (income) for the third quarter and first nine months of 2014 versus 2013 resulted from net gains on the sale of certain fixed assets and higher gains on sales of oil and gas well equipment and supplies in the 2014 periods.

Income Tax Expense

The components of our provision for income taxes are as follows:

	Three months ended September 30,		Nine months ended September 30,	
(in thousands)	2014	2013	2014	2013
Current benefit	$ —	$ —	$ —	$ —
Deferred taxes	84,707	81,823	254,210	211,615
	$ 84,707	$ 81,823	$ 254,210	$ 211,615
Combined Federal and State effective income tax rate	37.0 %	37.2 %	37.1 %	37.2 %

Our combined Federal and state effective tax rates differ from the statutory rate of 35% primarily due to state income taxes and non-deductible expenses. See Note 8 to the Consolidated Financial Statements of this report for additional information regarding our income taxes.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our liquidity is highly dependent on prices we receive for the oil, gas and NGLs we produce. Prices received for production heavily influence our revenue, cash flow, profitability, access to capital and future rate of growth. See RESULTS OF OPERATIONS above for a discussion of the impact realized prices had on our 2014 revenues.

Commodity prices are market driven and future prices will likely continue to fluctuate due to supply and demand factors, seasonality and other geopolitical and economic factors. We deal with volatility in commodity prices by maintaining flexibility in our capital investment program. In addition, we have periodically hedged a portion of our oil and/or gas production to mitigate our potential exposure to price declines and the corresponding negative impact on cash flow available for investment.

Our 2014 exploration and development (E&D) capital expenditures are expected to total approximately $1.95 billion and overall capital expenditures are expected to approximate $2.9 billion. Our capital expenditures are generally funded with cash flow provided by operating activities and long-term debt. Sales of non-core assets supplement funding of capital expenditures. The timing of capital expenditures and the receipt of cash flows do not necessarily match, which may cause us to borrow and repay funds under our bank credit facility.

At September 30, 2014, our long-term debt totaled $1.5 billion and consisted of $750 million of 4.375% senior notes due in 2024 and $750 million of 5.875% senior notes due in 2022. We had letters of credit outstanding under our bank credit facility of $2.5 million, leaving an unused borrowing availability of $997.5 million.

Our debt to total capitalization at September 30, 2014 was 25%. The reconciliation of debt to total capitalization, which is a non-GAAP measure, is: long-term debt of $1.5 billion divided by long-term debt of $1.5 billion plus stockholders' equity of $4.4 billion. Management believes that this non-GAAP measure is useful information as it is a common statistic used in the investment community to assist with the analysis of the financial condition of an entity.

We believe that our operating cash flow and other capital resources will be adequate to meet our needs for planned capital expenditures, working capital, debt servicing and dividend payments for the remainder of 2014 and beyond.

Analysis of Cash Flow Changes

Cash and cash equivalents on September 30, 2014 were $563.7 million, an increase of $559.1 million from $4.5 million at December 31, 2013. During the nine months ended September 30, 2014, cash flow provided by operating activities exceeded net cash flow used in investing activities by $24.1 million. In addition, net cash provided by financing activities was $535.0 million, primarily from a public debt offering in the second quarter of 2014.

For the first nine months of 2013, our net cash flow used for investing activities of $1.131 billion was $190.6 million greater than net cash flow provided by operating activities. Net bank borrowings of $150.0 million plus proceeds from issuance of common stock from employee option exercises, less dividend payments, provided $125.6 million of net cash flow from financing activities to fund investing activities. The remaining shortfall was made up from the use of cash and cash equivalents on hand of $65.0 million.

Cash flow provided by operating activities for the first nine months of 2014 was $1.272 billion compared to $940.7 million for the same period of 2013. The $331.2 million (35%) increase was primarily a result of increased revenues from greater production volumes and higher realized prices for natural gas and NGLs, which were partially offset by increased operating expenses.

During the first nine months of 2014, net cash flow used for investing activities increased by ten percent to $1.248 billion, compared to $1.131 billion for 2013. The net increase of $116.5 million was due to a $507.5 million increase in investments in oil and gas properties and other assets which were largely offset by higher proceeds from sales of oil and gas properties and other assets of $391.0 million. Most of the asset sales occurred in the third quarter of 2014.

Cash provided by financing activities during the first nine months of 2014 was $535.0 million, an increase of $409.5 million compared to $125.5 million for the same period of 2013. The majority of the increase relates to our June 2014 issuance of $750 million of senior notes. Proceeds from the debt offering were used to pay outstanding bank debt, financing costs associated with the debt offering and to fund investing activities. Similar additional financing activities in both the 2014 and 2013 periods included dividend payments and proceeds from issuance of common stock from employee option exercises.

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Reconciliation of Adjusted Cash Flow from Operations

(in thousands)	Nine months ended September 30, 2014	2013
Net cash provided by operating activities	$ 1,271,970	$ 940,748
Change in operating assets and liabilities	19,782	91,971
Adjusted cash flow from operations	$ 1,291,752	$ 1,032,719

Management believes that the non-GAAP measure of adjusted cash flow from operations is useful information for investors. It is accepted by the investment community as a means of measuring a company's ability to fund its capital program without reflecting fluctuations caused by changes in current assets and liabilities (which are included in the GAAP measure of cash flow from operating activities). It is also used by professional research analysts in providing investment recommendations pertaining to companies in the oil and gas exploration and production industry.

Capital Expenditures

The following table sets forth certain historical information regarding our capitalized expenditures for our oil and gas acquisition, exploration and development activities, and property sales:

	Three months ended September 30,		Nine months ended September 30,	
(in thousands)	2014	2013	2014	2013
Acquisitions:				
Proved (*)	$ —	$ (246)	$ 144,516	$ 677
Unproved	—	1,816	114,732	5,481
	—	1,570	259,248	6,158
Exploration and development:				
Land and seismic	34,697	59,035	143,891	127,064
Exploration and development	424,861	328,655	1,280,036	1,059,546

	459,558	387,690	1,423,927	1,186,610
Sales proceeds:				
Proved (*)	(271,954)	1,212	(272,177)	(36,667)
Unproved	(174,403)	—	(175,303)	(1,041)
	(446,357)	1,212	(447,480)	(37,708)
	$ 13,201	$ 390,472	$ 1,235,695	$ 1,155,060

(*) The negative amount in third quarter 2013 proved acquisitions and the positive amount in third quarter 2013 proved sales proceeds reflect net purchase price adjustments related to second quarter 2013 activity.

Capital expenditures in the table above are presented on an accrual basis. Oil and gas expenditures and sales in the Condensed Consolidated Statements of Cash Flows in this report reflect activities on a cash basis, when payments are made.

We expect our total 2014 E&D capital investment to approximate $1.95 billion, almost all of which is focused on oil and liquids-rich gas wells in the Permian Basin and Mid-Continent region. E&D expenditures of $1.424 billion during the first three quarters of 2014 were $237.3 million (20%) higher than $1.187 billion of expenditures during the 2013 period. Through September 30, 2014, approximately 72% of our 2014 expenditures were for Permian Basin projects with the majority of the remainder invested in projects in the Mid-Continent.

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The following table reflects wells drilled and completed by region:

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Gross wells				
Permian Basin	36	42	117	132
Mid-Continent	30	67	106	154
Other	—	3	2	5
	66	112	225	291
Net wells				
Permian Basin	27	28	78	87
Mid-Continent	9	21	43	56
Other	—	3	1	4
	36	52	122	147
% Gross wells completed as producers	98 %	99 %	99 %	99 %

As of September 30, 2014, we had 52 gross wells awaiting completion: 43 Permian Basin and 9 Mid-Continent. We also had 22 operated rigs running: 18 in the Permian Basin and 4 in the Mid-Continent region. We regularly review our E&D capital expenditures and will adjust our activity based on changes in commodity prices, service costs and drilling success.

In the ordinary course of business we make property acquisitions and dispositions, primarily to enhance our competitive position. During the first nine months of 2014, we made property acquisitions totaling $259.2 million mostly for producing and nonproducing properties located in the Cana-Woodford shale play. During the same period of 2013, we had property acquisitions of $6.2 million.

In the first nine months of 2014, we sold various non-core properties for net proceeds of approximately $447.5 million. Most of the proceeds were related to sales of producing gas wells in southwestern Kansas and undeveloped acreage in Reagan County, Texas. In the same period of 2013 we had non-core oil and gas property dispositions of $37.7 million and also sold fixed asset gas gathering and processing systems for $31 million.

We have made, and will continue to make, expenditures to comply with environmental and safety regulations and requirements. These costs are considered a normal recurring cost of our ongoing operations. We do not anticipate that we will be required to expend amounts that will have a material adverse effect on our financial position or operations, nor are we aware of any pending regulatory changes that would have a material impact.

Financial Condition

Future cash flows and the availability of financing are subject to a number of variables including success in finding and economically producing new reserves, production from existing wells and realized commodity prices. To meet capital and liquidity requirements, we rely on certain resources, including cash flows from operating activities, bank borrowings, and access to capital markets. When necessary, we use our bank credit facility to finance our working capital needs.

During the first nine months of 2014, our total assets increased by $1.4 billion to $8.6 billion, up from $7.3 billion at December 31, 2013. Half of the increase resulted from a $692.6 million increase in our net oil and gas properties. Most of the remaining increase relates to a $559.1 million increase in our cash and cash equivalents, primarily from third quarter asset sales.

Total liabilities at September 30, 2014 increased to $4.2 billion, up $983.2 million from $3.2 billion at year-end 2013. Over half of the increase relates to additional debt of $576.0 million resulting from our senior notes offering completed in the second quarter of 2014. Most of the remaining increase comes from a $250.8 million increase in deferred income taxes during 2014.

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Stockholders' equity totaled $4.4 billion at September 30, 2014, up $407.8 million from $4.0 billion at December 31, 2013. The increase resulted mainly from net income of $431.4 million less dividends of $41.7 million.

Dividends

A quarterly cash dividend has been paid to stockholders every quarter since the third quarter of 2006. In February 2014, the quarterly dividend was increased to $0.16 per share from $0.14 per share. Future dividend payments will depend on our level of earnings, financial requirements, and other factors considered relevant by our Board of Directors.

Working Capital Analysis

Our working capital balance fluctuates primarily as a result of changes in our cash and cash equivalents, exploration and development activities, realized commodity prices, and changes related to our operating activities. Working capital is also impacted by changes in our oil and gas well equipment and supplies, our current tax provision and changes in the fair value of our outstanding derivative instruments.

At September 30, 2014, we had working capital of $294.9 million, an increase of $508.9 million compared to a deficit of $214.0 million at December 31, 2013.

Working capital increases consisted of the following:

- Cash and cash equivalents increased by $559.1 million, primarily from third quarter asset sales.
- Operations-related accounts receivable increased by $63.3 million.
- Oil and gas well equipment and supplies increased by $26.2 million.

Increases in working capital were partially offset by the following:

- Operations related accounts payable and accrued liabilities increased by $90.2 million.
- Accrued liabilities related to our E&D expenditures increased by $42.5 million.
- Deferred income tax assets decreased by $3.3 million.
- The net fair value of our derivative instruments declined by $2.9 million.

Accounts receivable are a major component of our working capital and include a diverse group of companies comprised of major energy companies, pipeline companies, local distribution companies and other end-users. The collection of receivables during the periods presented has been timely. Historically, losses associated with uncollectible receivables have not been significant.

Long-term Debt

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

(in thousands)	September 30, 2014	December 31, 2013
Bank debt	$ —	$ 174,000
5.875% Senior Notes due 2022	750,000	750,000
4.375% Senior Notes due 2024	750,000	—
Total long-term debt	$ 1,500,000	$ 924,000

Bank Debt

In May 2014, we amended our senior unsecured revolving credit facility (Credit Facility) to extend the maturity date two years to July 14, 2018 and lowered the margins applicable to loans and commitments. The amendment also raised our borrowing base from $2.25 billion to $2.5 billion until the next regular annual redetermination date scheduled for April 15, 2015. The borrowing base is determined at the discretion of the lenders based on the value of our proved reserves. Our aggregate commitments remained unchanged at $1 billion.

As of September 30, 2014, we had letters of credit outstanding of $2.5 million, leaving an unused borrowing availability of $997.5 million. During the first nine months of 2014 we had average daily bank debt outstanding of $177.2 million, compared to $147.4 million for the same period of 2013. Our highest amount of bank borrowings outstanding during the first nine months of 2014 was $515.0 million, occurring in May. During the same period of 2013, the highest amount of outstanding bank borrowings was $285.0 million, occurring in September.

At our option, borrowings under the Credit Facility, as amended, may bear interest at either (a) LIBOR plus 1.5-2.25%, based on our leverage ratio, or (b) the higher of (i) a prime rate, (ii) the federal funds effective rate plus 0.50%, or (iii) adjusted one-month LIBOR plus 1.0% plus, in each case, an additional 0.5-1.25%, based on our leverage ratio.

The Credit Facility has a number of financial and non-financial covenants of which we were in compliance with at September 30, 2014. See Note 7 to the Consolidated Financial Statements in this report for further information.

5.875% Notes due 2022

In April 2012, we issued $750 million of 5.875% senior notes due May 1, 2022, with interest payable semiannually in May and November. The notes were sold to the public at par. The notes are governed by an indenture containing certain covenants, events of default and other restrictive provisions. We may redeem the notes in whole or in part, at any time on or after May 1, 2017, at redemption prices of 102.938% of the principal amount as of May 1, 2017, declining to 100% on May 1, 2020 and thereafter.

4.375% Notes due 2024

In June 2014, we issued $750 million of 4.375% senior notes due June 1, 2024, with interest payable semiannually in June and December. The notes were sold to the public at par. The notes are governed by an indenture containing certain covenants, events of default and other restrictive provisions. At any time prior to March 1, 2024, we may redeem all or a part of the notes at a defined make-whole redemption price calculated at the time of redemption. At any time on or after March 1, 2024, we may redeem all or part of the notes at a price equal to 100% of the principal amount.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of September 30, 2014, our material off-balance sheet arrangements included operating lease agreements, which are customary in the oil and gas industry and are included in the table below.

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Contractual Obligations and Material Commitments

At September 30, 2014, we had contractual obligations and material commitments as follows:

	Payments Due by Period				
Contractual obligations: (in thousands)	Total	1 Year or Less	2 - 3 Years	4 - 5 Years	More than 5 Years
Long-term debt (1)	$ 1,500,000	$ —	$ —	$ —	$ 1,500,000
Fixed-Rate interest payments (1)	680,352	76,602	153,750	153,750	296,250
Operating leases	125,972	12,857	21,871	20,818	70,426
Drilling commitments (2)	266,474	245,119	21,355	—	—
Gathering facilities and pipelines (3)	5,876	5,876	—	—	—
Asset retirement obligation (4)	170,328	16,387	— (4)	— (4)	— (4)
Other liabilities (5)	81,397	20,141	42,303	—	18,953
Firm transportation	469	386	83	—	—

(1) See Item 3: Quantitative and Qualitative Disclosures About Market Risk for more information regarding fixed and variable rate debt.
(2) We have drilling commitments of approximately $212.8 million consisting of obligations to finish drilling and completing wells in progress at September 30, 2014. We also have various commitments for drilling rigs. The total minimum expenditure commitments under these agreements are $53.7 million.
(3) We have projects in New Mexico and Texas where we are constructing gathering facilities and pipelines. At September 30, 2014, we had commitments of $5.9 million relating to this construction.
(4) We have not included the long-term asset retirement obligations because we are not able to precisely predict the timing of these amounts.
(5) Other liabilities include the estimated value of our commitment associated with our benefit obligations and other miscellaneous commitments.

At September 30, 2014, we had firm sales contracts to deliver approximately 45.2 Bcf of natural gas over the next 15 months. In total, our financial exposure would be approximately $166.6 million should we not deliver this gas. Our exposure will fluctuate with price volatility and actual volumes delivered. However, we believe Cimarex has no financial exposure from these contracts based on our current proved reserves and production levels from which we can fulfill these obligations.

In the normal course of business we have various delivery commitments which are not material individually or in the aggregate. All of the noted commitments were routine and were made in the normal course of our business.

Based on current commodity prices and anticipated levels of production, we believe that estimated net cash generated from operations and our other capital resources will be adequate to meet future liquidity needs.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

We consider accounting policies related to oil and gas reserves, full cost accounting, goodwill, contingencies and asset retirement obligations to be critical policies and estimates. These critical policies and estimates are summarized in Management's Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report on Form 10-K.

Recent Accounting Developments

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2014-09, Revenue from Contracts with Customers (Topic 606). The new revenue standard provides a five-step analysis of transactions to determine when and how revenue is recognized. The core principle of the guidance

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is that a company should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The guidance in this update supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance throughout the Industry Topics of the Codification. We must comply with this ASU beginning in fiscal year 2017 and early adoption is not permitted. Entities can choose to apply the standard using either the full retrospective approach or a modified retrospective approach. We are currently evaluating the impact of the provisions of Topic 606 and the effects of adoption cannot be determined at this time.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The term “market risk” refers to the risk of loss arising from adverse changes in commodity prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses.

Price Fluctuations

Our major market risk is pricing applicable to our oil and gas production. The prices we receive for our production are based on prevailing market conditions and are influenced by many factors that are beyond our control. Pricing for oil, gas and NGL production has been volatile and unpredictable.

We periodically enter into financial derivative contracts to hedge a portion of our price risk associated with our future oil and gas production.

The following tables detail the financial derivative contracts we have in place as of September 30, 2014:

Oil Contracts

Period	Type	Volume/Day	Index (1)	Weighted Average Price Floor	Ceiling	Fair Value (in thousands)
Oct 14 – Dec 14	Collars	12,000 Bbls	WTI	$ 85.00	$ 103.47	$ 1,089

(1) WTI refers to West Texas Intermediate price as quoted on the New York Mercantile Exchange.

Gas Contracts

Period	Type	Volume/Day	Index (1)	Weighted Average Price Floor	Ceiling	Fair Value (in thousands)
Oct 14 – Dec 14	Collars	80,000 MMBtu	PEPL	$ 3.51	$ 4.57	$ (81)
Oct 14 – Dec 14	Collars	60,000 MMBtu	Perm EP	$ 3.62	$ 4.50	$ (74)

(1) PEPL refers to Panhandle Eastern Pipe Line, Tex/OK Mid-Continent Index as quoted in Platt’s Inside FERC. Perm EP refers to El Paso Natural Gas Company, Permian Basin Index as quoted in Platt's Inside FERC.

While these contracts limit the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. For the oil contracts listed above, a hypothetical $1.00 change in the price below or above the contracted price applied to the notional amounts would cause a change in our gain (loss) on mark-to-market derivatives in 2014 of $1.1 million. For the gas contracts listed above, a hypothetical $0.10 change in the price below or above the contracted price applied to the notional amounts would cause a change in our gain (loss) on mark-to-market derivatives in 2014 of $1.3 million.

Counterparty credit risk did not have a significant effect on our cash flow calculations and commodity derivative valuations. This is primarily because we have mitigated our exposure to any single counterparty by contracting with numerous counterparties and because our derivative contracts are held with “investment grade”

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counterparties that are a part of our credit facility. See Note 2 to the Consolidated Financial Statements of this report for additional information regarding our derivative instruments.

Interest Rate Risk

At September 30, 2014, our long-term debt consisted of $750 million in 5.875% senior notes that will mature on May 1, 2022 and $750 million in 4.375% senior notes that will mature on June 1, 2024. Because all of our long-term debt is at a fixed rate, we consider our interest rate exposure to be minimal. This sensitivity analysis for interest rate risk excludes accounts receivable, accounts payable and accrued liabilities because of the short-term maturity of such instruments. See Note 3 and Note 7 to the Consolidated Financial Statements in this report for additional information regarding debt.

ITEM 4. CONTROLS AND PROCEDURES

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Cimarex management, under the supervision and with the participation of the Chief Executive Officer (CEO) and Chief Financial Officer (CFO), have evaluated the effectiveness of disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)) as of September 30, 2014. Based on that evaluation, the CEO and CFO concluded that the disclosure controls and procedures are effective in providing reasonable assurance that information required to be disclosed in reports filed with the SEC is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms. The disclosure controls and procedures are designed to provide reasonable assurance that such information is accumulated and communicated to our management, including the CEO and CFO, as appropriate, to allow such persons to make timely decisions regarding required disclosures.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There was no change in our internal control over financial reporting that occurred during the fiscal quarter ended September 30, 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II

ITEM 1. LEGAL PROCEEDINGS

In the H.B. Krug, et al. v. Helmerich & Payne, Inc. (H&P) case, on December 13, 2013 the Oklahoma Supreme Court reversed the Tulsa County District Court's original judgment of $119.6 million and affirmed an alternative jury verdict for $3.65 million. It also remanded the case back to the trial court for consideration of potential prejudgment interest, attorney's fees and cost awards. Accordingly, on December 31, 2013 we reduced the previously recognized litigation expense and the associated long-term liability by $142.8 million. On April 1, 2014, Cimarex paid the Plaintiffs $15.8 million in satisfaction of the $3.65 million damages award, the post-judgment interest award and the payment in lieu of bond, all of which are now final and not appealable. On June 24, 2014, the trial court ruled the Plaintiffs were not entitled to prejudgment interest but were entitled to attorney's fees and costs, the amount of which will be determined at a subsequent hearing. On July 31, 2014, the Plaintiffs appealed the trial court's denial of prejudgment interest, which will be determined by the Oklahoma Supreme Court. The outcome of these remaining issues cannot be determined, and our current estimates and assessments likely will change, as a result of these future legal proceedings.

Additional information regarding this and other litigation is included in Note 11 to the Consolidated Financial Statements included in Part I, Item 1 of this report.

ITEM 6. EXHIBITS

31.1	Certification of Thomas E. Jorden, Chief Executive Officer of Cimarex Energy Co., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Paul Korus, Chief Financial Officer of Cimarex Energy Co., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Thomas E. Jorden, Chief Executive Officer of Cimarex Energy Co., pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350.
32.2	Certification of Paul Korus, Chief Financial Officer of Cimarex Energy Co., pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350.
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

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SIGNATURES

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

November 5, 2014

CIMAREX ENERGY CO.

/s/ Paul Korus
Paul Korus
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ James H. Shonsey
James H. Shonsey
Vice President, Chief Accounting Officer and Controller
(Principal Accounting Officer)