SM Energy Co
Form 10-Q
July 30, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2014
Commission File Number 001-31539
SM ENERGY COMPANY
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	41-0518430 (I.R.S. Employer Identification No.)
1775 Sherman Street, Suite 1200, Denver, Colorado (Address of principal executive offices)	80203 (Zip Code)

(303) 861-8140
(Registrant's telephone number, including area code)

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

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

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

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

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

As of July 23, 2014, the registrant had 67,371,842 shares of common stock, $0.01 par value, outstanding.

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PART I. FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)
(in thousands, except share amounts)

	June 30, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$163,794	$282,248
Accounts receivable	312,415	318,371
Derivative asset	3,613	21,559
Deferred income taxes	12,086	10,749
Prepaid expenses and other	15,007	14,574
Total current assets	506,915	647,501
Property and equipment (successful efforts method):		
Proved oil and gas properties	6,151,765	5,637,462
Less - accumulated depletion, depreciation, and amortization	(2,883,506)	(2,583,698)
Unproved oil and gas properties	388,336	271,100
Wells in progress	495,052	279,654
Oil and gas properties held for sale net of accumulated depletion, depreciation and amortization of $23,697 and $7,390, respectively	23,935	19,072
Other property and equipment, net of accumulated depreciation of $33,529 and $28,775, respectively	258,619	236,202
Total property and equipment, net	4,434,201	3,859,792
Noncurrent assets:		
Derivative asset	1,300	30,951
Restricted cash	5,499	96,713
Other noncurrent assets	56,120	70,208
Total other noncurrent assets	62,919	197,872
Total Assets	$5,004,035	$4,705,165
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$592,493	$606,751
Derivative liability	92,088	26,380
Other current liabilities	—	6,000
Total current liabilities	684,581	639,131
Noncurrent liabilities:		
Revolving credit facility	—	—
Senior Notes (note 5)	1,600,000	1,600,000
Asset retirement obligation	117,916	115,659
Asset retirement obligation associated with oil and gas properties held for sale	2,760	3,033
Net Profits Plan liability	48,104	56,985
Deferred income taxes	725,408	650,125
Derivative liability	52,847	4,640
Other noncurrent liabilities	26,467	28,771

Total noncurrent liabilities	2,573,502	2,459,213
Commitments and contingencies (note 6)		
Stockholders' equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued: 67,116,732 and 67,078,853 shares outstanding, respectively; net of treasury shares: 67,116,732 and 67,056,441, respectively	671	671
Additional paid-in capital	273,664	257,720
Treasury stock, at cost: zero and 22,412 shares, respectively	—	(823)
Retained earnings	1,476,703	1,354,669
Accumulated other comprehensive loss	(5,086)	(5,416)
Total stockholders' equity	1,745,952	1,606,821
Total Liabilities and Stockholders' Equity	$5,004,035	$4,705,165

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

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SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)
(in thousands, except per share amounts)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Operating revenues:				
Oil, gas, and NGL production revenue	$654,661	$534,520	$1,277,770	$1,004,095
Other operating revenues	20,319	24,840	29,930	39,445
Total operating revenues	674,980	559,360	1,307,700	1,043,540
Operating expenses:				
Oil, gas, and NGL production expense	177,598	149,737	341,307	275,370
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	187,781	225,731	364,996	424,440
Exploration	24,270	20,657	45,605	36,055
Impairment of proved properties	—	34,552	—	55,771
Abandonment and impairment of unproved properties	164	4,339	2,965	4,641
General and administrative	38,115	35,374	73,166	67,654
Change in Net Profits Plan liability	(7,105)	(5,438)	(8,881)	(7,363)
Derivative loss (gain)	126,469	(85,190)	224,131	(54,618)
Other operating expenses	5,972	35,314	14,061	51,108
Total operating expenses	553,264	415,076	1,057,350	853,058
Income from operations	121,716	144,284	250,350	190,482
Non-operating income (expense):				
Interest expense	(24,040)	(21,581)	(48,230)	(40,682)
Other, net	(1,847)	24	(1,821)	36
Income before income taxes	95,829	122,727	200,299	149,836
Income tax expense	(36,049)	(46,205)	(74,912)	(56,587)
Net income	$59,780	$76,522	$125,387	$93,249
Basic weighted-average common shares outstanding	67,069	66,295	67,063	66,254
Diluted weighted-average common shares outstanding	68,239	67,893	68,180	67,711
Basic net income per common share	$0.89	$1.15	$1.87	$1.41
Diluted net income per common share	$0.88	$1.13	$1.84	$1.38
Dividends per common share	$—	$—	$0.05	$0.05

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)
(in thousands)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
Net income	$59,780	$76,522	$125,387	$93,249
Other comprehensive income (loss), net of tax:				
Reclassification to earnings [1]	—	746	—	807
Pension liability adjustment	330	—	330	(3)
Total other comprehensive income, net of tax	330	746	330	804
Total comprehensive income	$60,110	$77,268	$125,717	$94,053

[1] Reclassification from accumulated other comprehensive loss (“AOCL”) related to de-designated hedges. As of December 31, 2013, all commodity derivative contracts that had been designated as cash flow hedges were settled and reclassified into earnings from AOCL.

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)
(in thousands)

	For the Six Months Ended June 30,	
	2014	2013
Cash flows from operating activities:		
Net income	$125,387	$93,249
Adjustments to reconcile net income to net cash provided by operating activities:		
Gain on divestiture activity	(5,484)	(5,706)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	364,996	424,440
Exploratory dry hole expense	6,459	5,886
Impairment of proved properties	—	55,771
Abandonment and impairment of unproved properties	2,965	4,641
Stock-based compensation expense	14,341	18,068
Change in Net Profits Plan liability	(8,881)	(7,363)
Derivative loss (gain)	224,131	(54,618)
Derivative cash settlement (loss) gain	(62,620)	14,003
Amortization of deferred financing costs	2,954	2,440
Deferred income taxes	73,911	56,239
Plugging and abandonment	(3,219)	(3,746)
Other, net	(4,827)	5,769
Changes in current assets and liabilities:		
Accounts receivable	(2,558)	(59,284)
Prepaid expenses and other	1,302	(32)
Accounts payable and accrued expenses	(13,704)	46,598
Net cash provided by operating activities	715,153	596,355
Cash flows from investing activities:		
Net proceeds from sale of oil and gas properties	46,821	20,343
Capital expenditures	(778,580)	(733,992)
Acquisition of proved and unproved oil and gas properties	(98,619)	(59,201)
Other, net	(2,257)	(4,940)
Net cash used in investing activities	(832,635)	(777,790)
Cash flows from financing activities:		
Proceeds from credit facility	—	516,500
Repayment of credit facility	—	(828,500)
Deferred financing costs related to credit facility	—	(3,444)
Net proceeds from 2024 Notes	—	490,820
Proceeds from sale of common stock	2,490	3,652
Dividends paid	(3,353)	(3,314)
Other, net	(109)	(29)
Net cash provided by (used in) financing activities	(972)	175,685
Net change in cash and cash equivalents	(118,454)	(5,750)
Cash and cash equivalents at beginning of period	282,248	5,926
Cash and cash equivalents at end of period	$163,794	$176

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

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SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED) (Continued)

Supplemental schedule of additional cash flow information and non-cash investing and financing activities:

	For the Six Months Ended June 30,	
	2014	2013
	(in thousands)	
Cash paid for interest, net of capitalized interest	$47,403	$36,089
Net cash paid (refunded) for income taxes	$162	$(332)

As of June 30, 2014, and 2013, $328.6 million and $243.5 million, respectively, of accrued capital expenditures were included in accounts payable and accrued expenses in the Company's condensed consolidated balance sheets. These oil and gas property additions are reflected in cash used in investing activities in the periods during which the payables are settled.

During the second quarter of 2014, the Company exchanged properties in its Rocky Mountain region for other properties also located in its Rocky Mountain region with a fair value of $6.2 million. The amount of cash consideration paid at closing for agreed upon adjustments is reflected in the acquisition of proved and unproved oil and gas properties line item in the condensed consolidated statements of cash flows.

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

SM ENERGY COMPANY AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

Note 1 - The Company and Business

SM Energy Company ("SM Energy" or the "Company") is an independent energy company engaged in the acquisition, exploration, development, and production of crude oil and condensate, natural gas, and natural gas liquids (also respectively referred to as "oil," "gas," and "NGLs" throughout this report) in onshore North America, with a current focus on oil and liquids-rich resource plays.

Note 2 - Basis of Presentation, Significant Accounting Policies, and Recently Issued Accounting Standards

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements of SM Energy have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP") for interim financial information and the instructions to Form 10-Q and Regulation S-X. They do not include all information and notes required by GAAP for complete financial statements. However, except as disclosed herein, there has been no material change in the information disclosed in the notes to consolidated financial statements included in SM Energy's Annual Report on Form 10-K for the year ended December 31, 2013 (the "2013 Form 10-K"). In the opinion of management, all adjustments, consisting of normal recurring accruals considered necessary for a fair presentation of interim financial information, have been included. Operating results for the periods presented are not necessarily indicative of expected results for the full year. In connection with the preparation of its unaudited condensed consolidated financial statements, the Company evaluated events subsequent to the balance sheet date of June 30, 2014, through the filing date of this report.

Significant Accounting Policies

The significant accounting policies followed by the Company are set forth in Note 1 to the Company's consolidated financial statements in its 2013 Form 10-K, and are supplemented by the notes to the unaudited condensed consolidated financial statements in this report. These unaudited condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes included in the 2013 Form 10-K.

Recently Issued Accounting Standards

In April 2014, the Financial Accounting Standards Board ("FASB") issued new authoritative accounting guidance related to the recognition and presentation of discontinued operations in the financial statements. The guidance intends to reduce the frequency of disposals reported as discontinued operations by focusing on strategic shifts that have or will have a major effect on an entity's operations and financial results. This authoritative accounting guidance is effective for interim and annual periods beginning after December 15, 2014, and is to be applied prospectively. The Company is currently evaluating the provisions of this authoritative guidance and assessing its impact, but does not believe it will have a material effect on the Company's financial statements or disclosures.

In May 2014, the FASB issued new authoritative accounting guidance related to the recognition of revenue. This authoritative accounting guidance is effective for the annual period beginning after December 15, 2016, including interim periods within that reporting period, and is to be applied using one of two acceptable methods. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company's financial statements and disclosures.

In June 2014, the FASB issued new authoritative accounting guidance related to the recognition of share-based compensation when an award provides that a performance target can be achieved after the requisite service period. This authoritative accounting guidance may be applied either prospectively or retrospectively and is effective for annual periods and interim periods beginning after December 15, 2015. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company’s financial statements and disclosures.

There are no other new significant accounting standards applicable to the Company that have been issued but not yet adopted by the Company as of June 30, 2014, and through the filing date of this report.

Note 3 – Acquisitions, Divestitures, and Assets Held for Sale
Acquisitions

During the second quarter of 2014, the Company acquired acreage in the Powder River Basin for cash consideration of approximately $100.0 million, plus approximately 7,000 net non-core acres in the Company's Rocky Mountain region. Subsequent to June 30, 2014, the Company entered into multiple agreements to acquire producing and non-producing properties in its Rocky Mountain region for a total of approximately $345.0 million.

Divestitures

During the second quarter of 2014, the Company divested certain non-strategic assets in the Williston Basin located in its Rocky Mountain region. Total cash proceeds received at closing (referred throughout this report as "divestiture proceeds") were $50.2 million and the estimated net gain is $27.8 million. This divestiture is subject to normal post-closing adjustments, which are expected to be completed during the second half of 2014.

Assets Held for Sale

Assets are classified as held for sale when the Company commits to a plan to sell the assets and there is reasonable certainty the sale will take place within one year. Upon classification as held for sale, long-lived assets are no longer depreciated or depleted, and a measurement for impairment is performed to identify and expense any excess of carrying value over fair value less estimated costs to sell. Subsequent decreases to the estimated fair value less the costs to sell will impact the measurement of assets held for sale.

As of June 30, 2014, the accompanying condensed consolidated balance sheets ("accompanying balance sheets") present $23.9 million of oil and gas properties held for sale, net of accumulated depletion, depreciation, and amortization expense. A corresponding asset retirement obligation liability of $2.8 million is separately presented. Assets held for sale are recorded at the lesser of their carrying values or their respective fair value less estimated costs to sell. For the six months ended June 30, 2014, certain assets classified as held for sale were written down to fair value less estimated costs to sell, which is recorded as a loss on divestiture activity and is included within the other operating revenues line item in the accompanying condensed consolidated statements of operations ("accompanying statements of operations").

The Company determined that these planned asset sales do not qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

Note 4 - Income Taxes

Income tax expense for the three months and six months ended June 30, 2014, and 2013, differs from the amounts that would be provided by applying the statutory United States federal income tax rate to income before income taxes primarily due to the effect of state income taxes, changes in valuation allowances, percentage depletion, research and development ("R&D") credits, and other permanent differences. The quarterly rate can also be impacted by the proportional effects of forecasted net income as of each period end presented.

The provision for income taxes consists of the following:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
	(in thousands)			

Current portion of income tax expense:				
Federal	$—	$—	$—	$—
State	512	246	1,001	348
Deferred portion of income tax expense	35,537	45,959	73,911	56,239
Total income tax expense	$36,049	$46,205	$74,912	$56,587
	37.6 %	37.6 %	37.4 %	37.8 %

On a year-to-date basis, a change in the Company's effective tax rate between reported periods will generally reflect differences in its estimated highest marginal state tax rate due to changes in the composition of income from Company activities among various state tax jurisdictions. Cumulative effects of state rate changes are reflected in the period legislation is enacted. The decrease in the effective rate from the six months ended June 30, 2013, primarily reflects temporary and permanent changes in the mix of highest marginal state tax rates, the effects of valuation allowance adjustments, the state tax rate effect divestitures have between years, drilling activities, and changes in the effects of other permanent differences.

The Company and its subsidiaries file federal income tax returns and various state income tax returns. With certain exceptions, the Company is no longer subject to United States federal or state income tax examinations by tax authorities for years before 2007. Federal tax law allowing for the calculation of an R&D credit was enacted in 2013, which allowed the credit for the 2012 and 2013 tax years. However, the Company has not yet commissioned a study to calculate the credit for these tax years. The table above excludes the impact for any credit that could be claimed for the 2013 tax year. The Internal Revenue Service ("IRS") initiated an audit in the first quarter of 2012 related to R&D tax credits claimed by the Company for the 2007 through 2010 tax years. On April 23, 2013, the IRS issued a Notice of Proposed Adjustment disallowing $4.6 million of R&D tax credits claimed for open tax years during the audit period. The Company maintains it is entitled to claim the credits and is pursuing its appeal. The appeals process was ongoing at June 30, 2014, and through the filing date of this report.

On September 13, 2013, the United States Department of the Treasury and IRS issued the final and re-proposed tangible property regulations effective for tax years beginning January 1, 2014. The Company has determined it is materially compliant with the requirements of these regulations.

Note 5 - Long-term Debt

Revolving Credit Facility

The Company's Fifth Amended and Restated Credit Agreement provides a maximum loan amount of $2.5 billion, current aggregate lender commitments of $1.3 billion, and a maturity date of April 12, 2018. The borrowing base is subject to regular semi-annual redeterminations and was re-affirmed on March 28, 2014, at $2.2 billion. The borrowing base redetermination process under the credit facility considers the value of the Company's oil and gas properties and other assets, as determined by the lender group. The next scheduled redetermination date is October 1, 2014. Borrowings under the facility are secured by at least 75 percent of the Company's proved oil and gas properties.

The Company must comply with certain financial and non-financial covenants under the terms of its credit facility agreement, including limitations on the payment of dividends to $50.0 million per year. The Company was in compliance with all covenants under the credit facility as of June 30, 2014, and through the filing date of this report.

The following table presents the outstanding balance, total amount of letters of credit, and available borrowing capacity under the Company's credit facility as of July 23, 2014, June 30, 2014, and December 31, 2013:

	As of July 23, 2014	As of June 30, 2014	As of December 31, 2013
	(in thousands)		
Credit facility balance	$—	$—	$—
Letters of credit [(1)]	$808	$808	$808
Available borrowing capacity	$1,299,192	$1,299,192	$1,299,192

[(1)] Letters of credit reduce the available borrowing capacity under the credit facility on a dollar-for-dollar basis.

Senior Notes

The Senior Notes line on the accompanying balance sheets represents the outstanding principal amount of the 6.625% Senior Notes due 2019 (the “2019 Notes”), the 6.50% Senior Notes due 2021 (the “2021 Notes”), the 6.50% Senior Notes due 2023 (the “2023 Notes”), and the 5.0% Senior Notes due 2024 (the “2024 Notes” and collectively with the 2019 Notes, 2021 Notes, and 2023 Notes, the “Senior Notes”), as shown in the table below:

	As of June 30, 2014	As of December 31, 2013
	(in thousands)	
2019 Notes	$ 350,000	$ 350,000
2021 Notes	350,000	350,000
2023 Notes	400,000	400,000
2024 Notes	500,000	500,000
Total Senior Notes	$ 1,600,000	$ 1,600,000

The Senior Notes are unsecured senior obligations and rank equal in right of payment with all of the Company’s existing and any future unsecured senior debt, and are senior in right of payment to any future subordinated debt. There are no subsidiary guarantors of the Senior Notes. The Company is subject to certain covenants under the respective indentures governing the Senior Notes that limit the Company’s ability to incur additional indebtedness, issue preferred stock, and make restricted payments, including dividends; provided, however, that the first $6.5 million of dividends paid each year are not restricted by these covenants. The Company does not expect these restrictions to limit its ability to continue paying dividends at its current rate for the foreseeable future if declared by the Company’s Board of Directors. The Company was in compliance with all covenants under its Senior Notes as of June 30, 2014, and through the filing date of this report.

2024 Notes

On May 20, 2013, the Company issued $500.0 million in aggregate principal amount of 2024 Notes. The 2024 Notes were issued at par and mature on January 15, 2024. Please refer to Note 5 - Long-term Debt in the Company’s 2013 Form 10-K for additional discussion of the terms of these notes.

On May 20, 2013, the Company entered into a registration rights agreement that provided holders of the 2024 Notes certain registration rights under the Securities Act of 1933, as amended (the “Securities Act”). The Company closed its offer to exchange its 2024 Notes for notes registered under the Securities Act on June 25, 2014.

Note 6 - Commitments and Contingencies

Commitments

During the first six months of 2014, the Company entered into drilling rig contracts, with total minimum commitments of $91.5 million and varying terms extending through 2016. As of June 30, 2014, future minimum commitments under these contracts totaled $71.2 million. Subsequent to June 30, 2014, the Company entered into additional drilling rig contracts with future minimum commitments totaling $18.1 million.

Contingencies

The Company is subject to litigation and claims arising in the ordinary course of business. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. In the opinion of management, the results of such pending litigation and claims will not have a material effect on the results of operations, the financial position, or the cash flows of the Company.

On April 16, 2014, the Company agreed to settle its previously disclosed litigation against Endeavour Operating Corporation (“Endeavour”). The Company, its working interest partners, and Endeavour agreed to mutually release all claims and dismiss the lawsuit in exchange for certain cash payments and other consideration paid to the Company and its working interest partners by Endeavour. The Company recorded a $10.7 million gain in the other operating revenues line item in the accompanying statements of operations in the second quarter of 2014 relating to this settlement.

On January 27, 2011, Chieftain Royalty Company ("Chieftain") filed a Class Action Petition against the Company in the District Court of Beaver County, Oklahoma, claiming damages related to royalty payments on all of the Oklahoma oil and gas wells operated by the Company and its predecessors. These claims include breach of contract, breach of fiduciary duty, fraud, unjust enrichment, tortious breach of contract, conspiracy, and conversion, based generally on asserted improper deduction of post-production costs. The Company removed this lawsuit to the United States District Court for the Western District of Oklahoma on February 22, 2011. The Company responded to the petition and denied the allegations. The district court did not rule on Chieftain's motion to certify the putative class, and stayed all proceedings until the United States Court of Appeals for the Tenth Circuit issued its rulings on class certification in two similar royalty class action lawsuits. On July 9, 2013, the Tenth Circuit issued its opinions, reversing the trial courts' grant of class certification and remanding the matters to the trial courts for those cases. The district court presiding over the Company's case subsequently lifted its stay and the Company expects Chieftain to file a new motion for class certification in the first half of 2015.

This case involves complex legal issues and uncertainties; a potentially large class of plaintiffs, and a large number of related producing properties, lease agreements and wells; and an alleged class period commencing in 1988 and spanning the entire producing life of the wells. Because the proceedings are in the early stages, with discovery yet to be completed, the Company is unable to estimate what impact, if any, the action will have on its financial condition, results of operations, or cash flows. The Company is still evaluating the claims, but believes that it has properly paid royalties under Oklahoma law and has and will continue to vigorously defend this case. On December 30, 2013, the Company sold a substantial portion of the assets that were subject to this matter and the buyer assumed any such liabilities related to such properties.

Note 7 - Compensation Plans

Cash Bonus Plan

During the first six months of 2014 and 2013, the Company paid $41.7 million and $16.0 million, respectively, for cash bonuses earned during the 2013 and 2012 performance years, respectively. The general and administrative ("G&A") expense and exploration expense line items in the accompanying statements of operations include $6.2 million and $5.3 million of accrued cash bonus plan expense for the three months ended June 30, 2014, and 2013, respectively, and $12.8 million and $10.9 million of accrued cash bonus plan expense for the six months ended June 30, 2014, and 2013, respectively, related to the respective performance years.

Non-qualified Deferred Compensation Plan

In January 2014, the Company established a non-qualified deferred compensation ("NQDC") plan intended to provide plan participants with the ability to plan for income tax events and the opportunity to receive a benefit for matching contributions in excess of Internal Revenue Code ("IRC") limits applicable to the Company's 401(k) plan. The NQDC plan is designed to allow employee participants to defer a portion of base salary and cash bonuses paid pursuant to the Company's cash bonus plan and director participants to defer a portion of the cash retainer paid to directors. Each year, participating employees may elect to defer (i) between 0% and 50% of their base salary and (ii) between 0% and 100% of the cash bonus paid pursuant to the cash bonus plan, and participating directors may elect to defer between 0% and 100% of their cash retainer. The NQDC plan requires the Company to make contributions for each eligible employee equal to 100% of the deferred amount for such employee, limited to 6% of such employee's base salary and cash bonus. Each eligible employee's interest in contributions made by the Company will vest 40% after the second year of such employee's service to the Company, and 20% per year thereafter. A participant's account will be distributed based upon the participant's payment election made at the time of deferral. A participant may elect to have distributions made in lump sum or in annual installments ranging for a period from 1 to 10 years. Participants in the NQDC plan are currently limited to the Company's officers and directors.

Restricted Stock Units Under the Equity Incentive Compensation Plan

The Company grants restricted stock units (“RSUs”) as part of its equity compensation program. Each RSU represents a right to one share of the Company’s common stock to be delivered upon settlement of the award at the end of the specified vesting period. Expense associated with RSUs is recognized as G&A expense and exploration expense over the vesting period of the award.

Total expense recorded for RSUs for the three months ended June 30, 2014, and 2013, was $2.9 million and $3.3 million, respectively, and $5.7 million and $6.3 million for the six months ended June 30, 2014, and 2013, respectively. As of June 30, 2014, there was $12.8 million of total unrecognized compensation expense related to unvested RSU awards, which is being amortized through 2016. There have been no material changes to the outstanding and non-vested RSUs during the first half of 2014.

Subsequent to June 30, 2014, the Company granted 231,256 RSUs as part of its regular annual long-term equity compensation program. These RSUs will vest 1/3rd on each of the next three anniversary dates of the grant. Also, subsequent to June 30, 2014, the Company settled 243,389 RSUs that related to awards granted in previous years. The Company and the majority of grant participants mutually agreed to net share settle the awards to cover income and payroll tax withholdings as provided for in the plan document and award agreements. As a result, the Company issued 164,490 net shares of common stock. The remaining 78,899 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon delivery of the shares underlying those RSUs.

Performance Share Units Under the Equity Incentive Compensation Plan

The Company grants performance share units ("PSUs") as part of its equity compensation program. The number of shares of the Company's common stock issued to settle PSUs ranges from 0% to 200% of the number of PSUs awarded and is determined based on the Company's performance over a three-year measurement period. The performance criteria for the PSUs are based on a combination of the Company's annualized total shareholder return ("TSR") for the measurement period and the relative measure of the Company's TSR compared with the annualized TSRs of a group of peer companies for the measurement period. Expense associated with PSUs is recognized as G&A expense and exploration expense over the vesting period of the award.

Total expense recorded for PSUs for the three months ended June 30, 2014, and 2013, was $3.6 million and $5.0 million, respectively, and $6.8 million and $9.7 million for the six months ended June 30, 2014, and 2013, respectively. As of June 30, 2014, there was $11.3 million of total unrecognized compensation expense related to unvested PSU awards, which is being amortized through 2016. There have been no material changes to the outstanding and non-vested PSUs during the first half of 2014.

Subsequent to June 30, 2014, the Company granted 202,404 PSUs as part of its regular annual long-term equity compensation program. These PSUs will fully vest on the third anniversary of the date of the grant. Also, subsequent to June 30, 2014, the Company settled PSUs that were granted in 2011, which earned a 0.55 times multiplier, by issuing a net 85,121 shares of the Company's common stock in accordance with the terms of the PSU awards. The Company and the majority of grant participants mutually agreed to net share settle the awards to cover income and payroll tax withholdings as provided for in the plan document and award agreements. As a result, 45,042 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon delivery of the shares underlying those PSUs.

Stock Option Grants Under the Equity Incentive Compensation Plan

As of June 30, 2014, there were 39,088 stock option awards outstanding at a weighted average exercise price of $20.87 with an aggregate intrinsic value of $2.5 million. There was no unrecognized compensation expense as of June 30, 2014, and no changes in these awards occurred during the six months ended June 30, 2014.

Director Shares

During the first half of 2014 and 2013, the Company issued 23,009 and 28,169 shares, respectively, of its common stock to its non-employee directors, under the Company's Equity Incentive Compensation Plan. The Company recorded $1.2 million and $1.4 million of compensation expense related to these awards for both the three and six months ended June 30, 2014, and 2013, respectively.

The Company's Board of Directors appointed Rose M. Robeson as a non-employee director on July 11, 2014, and granted her 2,951 shares of the Company's common stock as her pro-rata share of the Company's annual director compensation.

All shares of common stock issued to the Company's non-employee directors are earned over the one-year service period following the date of grant.

Employee Stock Purchase Plan

Under the Company’s Employee Stock Purchase Plan (“ESPP”), eligible employees may purchase shares of the Company’s common stock through payroll deductions of up to 15 percent of eligible compensation, without accruing in excess of $25,000 in value from purchases for each calendar year. The purchase price of the stock is 85 percent of the lower of the fair market value of the stock on the first or last day of the purchase period, and shares issued under the ESPP have no restriction period. The ESPP is intended to qualify under Section 423 of the IRC. The Company had 1.2 million shares available for issuance under the ESPP as of June 30, 2014. There were 35,249 and 44,437 shares issued under the ESPP during the second quarters of 2014 and 2013, respectively. The fair value of ESPP grants is measured at the date of grant using the Black-Scholes option-pricing model.

Net Profits Interest Bonus Plan

Cash payments made or accrued under the Company’s Net Profits Interest Bonus Plan (“Net Profits Plan”) that have been recorded as either G&A expense or exploration expense are presented in the table below:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
	(in thousands)			
General and administrative expense	$1,986	$3,443	$4,964	$7,229
Exploration expense	194	323	482	697
Total	$2,180	$3,766	$5,446	$7,926

Additionally, the Company accrued or made cash payments under the Net Profits Plan of $8.5 million and $2.6 million for the three-month and six-month periods ended June 30, 2014, and 2013, respectively, as a result of divestiture proceeds. These cash payments are accounted for as a reduction in gain on divestiture activity included within the other operating revenues line in the accompanying statements of operations.

The Company records changes in the present value of estimated future payments under the Net Profits Plan as a separate line item in the accompanying statements of operations. The change in the estimated liability is recorded as a non-cash expense or benefit in the current period and is not allocated to G&A expense or exploration expense because it is associated with the future net cash flows from oil and gas properties in the respective pools rather than results being realized through current period production. If the Company allocated the change in liability to these specific functional line items, based on the current allocation of actual distributions made by the Company, such expenses or benefits would predominately be allocated to G&A expense. Over time, less of the amount distributed relates to prospective exploration efforts as more of the amount distributed is paid to employees that have terminated employment and do not provide ongoing exploration support to the Company. In December 2007, the Board of Directors discontinued the creation of new pools and as a result, the 2007 pool was the last Net Profits Plan pool established by the Company.

Note 8 - Pension Benefits

Pension Plans

The Company has a non-contributory pension plan covering substantially all employees who meet age and service requirements (the “Qualified Pension Plan”). The Company also has a supplemental non-contributory pension plan covering certain management employees (the “Nonqualified Pension Plan” and together with the Qualified Pension Plan, the “Pension Plans”).

Components of Net Periodic Benefit Cost for the Pension Plans

The following table presents the components of the net periodic benefit cost for the Pension Plans:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
	(in thousands)			
Service cost	$1,595	$1,914	$3,168	$3,146
Interest cost	688	468	1,095	813
	(604)	(483)	(989)	(769)

Expected return on plan assets that reduces periodic pension costs				
Amortization of prior service costs	5	5	9	9
Amortization of net actuarial loss	38	414	344	611
Net periodic benefit cost	$1,722	$2,318	$3,627	$3,810

Prior service costs are amortized on a straight-line basis over the average remaining service period of active participants. Gains and losses in excess of 10 percent of the greater of the benefit obligation and the market-related value of assets are amortized over the average remaining service period of active participants.

Contributions

The Company contributed $5.3 million to the Pension Plans during the six month period ended June 30, 2014.

Note 9 - Earnings per Share

Basic net income per common share is calculated by dividing net income available to common stockholders by the basic weighted-average common shares outstanding for the respective period. The Company's earnings per share calculations reflect the impact of any repurchases of shares of common stock made by the Company.

Diluted net income per common share is calculated by dividing adjusted net income by the diluted weighted-average common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist of in-the-money outstanding stock options, unvested RSUs, and contingent PSUs. The treasury stock method is used to measure the dilutive impact of unvested RSUs, contingent PSUs, and in-the-money stock options.

PSUs represent the right to receive, upon settlement of the PSUs after completion of the three-year performance period, a number of shares of the Company's common stock that may range from 0% to 200% of the number of PSUs granted on the award date. The number of potentially dilutive shares related to PSUs is based on the number of shares, if any, that would be issuable at the end of the respective reporting period, assuming that date was the end of the contingency period applicable to such PSUs. For additional discussion on PSUs, please refer to Note 7 - Compensation Plans under the heading Performance Stock Units Under the Equity Incentive Compensation Plan.

The following table sets forth the calculations of basic and diluted earnings per share:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
	(in thousands, except per share amounts)			
Net income	$59,780	$76,522	$125,387	$93,249
Basic weighted-average common shares outstanding	67,069	66,295	67,063	66,254
Add: dilutive effect of stock options, unvested RSUs, and contingent PSUs	1,170	1,598	1,117	1,457
Diluted weighted-average common shares outstanding	68,239	67,893	68,180	67,711
Basic net income per common share	$0.89	$1.15	$1.87	$1.41
Diluted net income per common share	$0.88	$1.13	$1.84	$1.38

Note 10 - Derivative Financial Instruments

Summary of Oil, Gas, and NGL Derivative Contracts in Place

The Company has entered into various commodity derivative contracts to mitigate a portion of its exposure to potentially adverse market changes in commodity prices and the associated impact on cash flows. All contracts are entered into for other-than-trading purposes. The Company's derivative contracts include swap and costless collar arrangements for oil, gas, and NGLs.

As of June 30, 2014, the Company had commodity derivative contracts outstanding through the second quarter of 2018 for a total of 15.1 million Bbls of oil production, 188.6 million MMBtu of gas production, and 2.6 million Bbls of NGL production. Subsequent to June 30, 2014, the Company entered into derivative contracts through the fourth quarter of 2016 for a total of 4.2 million Bbls of oil production with contract prices ranging from $89.35 per Bbl to $100.58 per Bbl.

In a typical commodity swap agreement, if the agreed upon published third-party index price ("index price") is lower than the swap fixed price, the Company receives the difference between the index price and the agreed upon swap fixed price. If the index price is higher than the swap fixed price, the Company pays the difference. For collar agreements, the Company receives the difference between an index price and the floor price if the index price is below the floor price. The Company pays the difference between the ceiling price and the index price if the index price is above the ceiling price. No amounts are paid or received if the index price is between the floor and ceiling prices.

The following tables summarize the approximate volumes and average contract prices of contracts the Company had in place as of June 30, 2014:

Oil Contracts

Oil Swaps

Contract Period	NYMEX WTI Volumes	Weighted-Average Contract Price
	(Bbls)	(per Bbl)
Third quarter 2014	1,533,000	$96.04
Fourth quarter 2014	1,353,000	$94.88
2015	4,248,000	$89.64
2016	2,704,000	$85.19
All oil swaps	9,838,000	

Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(Bbls)	(per Bbl)	(per Bbl)
Third quarter 2014	973,000	$85.00	$102.58
Fourth quarter 2014	923,000	$85.00	$102.63
2015	3,366,000	$85.00	$94.25
All oil collars	5,262,000		

Gas Contracts

Gas Swaps

Contract Period	Volumes	Weighted-Average Contract Price
	(MMBtu)	(per MMBtu)
Third quarter 2014	24,541,000	$4.02
Fourth quarter 2014	22,014,000	$4.02
2015	57,943,000	$4.04
2016	37,472,000	$4.17
2017	23,430,000	$4.21
2018	10,200,000	$4.31
All gas swaps*	175,600,000	

*Gas swaps are comprised of IF El Paso Permian (3%), IF HSC (82%), IF NGPL TXOK (2%), IF NNG Ventura (3%), IF Reliant N/S (9%), and IF CIG N System (1%).

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Gas Collars

Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(MMBtu)	(per MMBtu)	(per MMBtu)
2015	13,002,000	$3.98	$4.30
All gas collars*	13,002,000		

*Gas collars are comprised of IF El Paso Permian (4%), IF HSC (80%), IF NNG Ventura (8%), and IF Reliant N/S (8%).

NGL Contracts

NGL Swaps

Contract Period	Volumes	Weighted-Average Contract Price
	(Bbls)	(per Bbl)
Third quarter 2014	960,000	$58.06
Fourth quarter 2014	861,000	$58.06
2015	781,000	$55.42
All NGL swaps*	2,602,000	

*NGL swaps are comprised of Oil Price Information System ("OPIS") Mont Belvieu LDH Propane (72%) and OPIS Mont Belvieu NON-LDH Natural Gasoline (28%).

Derivative Assets and Liabilities Fair Value

The Company's commodity derivatives are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities. The fair value of the commodity derivative contracts was a net liability of $140.0 million and net asset of $21.5 million at June 30, 2014, and December 31, 2013, respectively.

The following tables detail the fair value of derivatives recorded in the accompanying balance sheets, by category:

	As of June 30, 2014			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity contracts	Current assets	$3,613	Current liabilities	$92,088
Commodity contracts	Noncurrent assets	1,300	Noncurrent liabilities	52,847
Derivatives not designated as hedging instruments		$4,913		$144,935

	As of December 31, 2013			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			

Commodity contracts	Current assets	$21,559	Current liabilities	$26,380
Commodity contracts	Noncurrent assets	30,951	Noncurrent liabilities	4,640
Derivatives not designated as hedging instruments		$52,510		$31,020

Offsetting of Derivative Assets and Liabilities

As of June 30, 2014, and December 31, 2013, all derivative instruments held by the Company were subject to enforceable master netting arrangements by various financial institutions. In general, the terms of the Company's agreements provide for offsetting of amounts payable or receivable between it and the counterparty, at the election of both parties, for settlements that occur on the same date and in the same currency. The Company's agreements also provide that in the event of an early termination, the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. The Company's accounting policy is to not offset these positions in its accompanying balance sheets.

The following table provides a reconciliation between the gross assets and liabilities reflected on the accompanying balance sheets and the potential effects of master netting arrangements on the fair value of the Company's derivative contracts:

	Derivative Assets As of		Derivative Liabilities As of	
Offsetting of Derivative Assets and Liabilities	June 30, 2014	December 31, 2013	June 30, 2014	December 31, 2013
	(in thousands)			
Gross amounts presented in the accompanying balance sheets	$4,913	$52,510	$(144,935)	$(31,020)
Amounts not offset in the accompanying balance sheets	(4,913)	(30,652)	4,913	30,652
Net amounts	$—	$21,858	$(140,022)	$(368)

The following table summarizes the components of the derivative loss (gain) presented in the accompanying statements of operations:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
	(in thousands)			
Derivative cash settlement loss (gain):				
Oil contracts	$20,160	$(29)	26,918	$248
Gas contracts	13,472	2,091	26,876	(7,733)
NGL contracts	48	(4,273)	8,826	(6,518)
Total derivative cash settlement loss (gain) (1)	33,680	(2,211)	62,620	(14,003)
Derivative loss (gain):				
Oil contracts	73,435	(26,044)	98,627	(22,255)
Gas contracts	14,682	(50,267)	60,739	(10,198)
NGL contracts	4,672	(6,668)	2,145	(8,162)
Total derivative loss (gain) (2)	$126,469	$(85,190)	$224,131	$(54,618)

(1) Total derivative cash settlement loss (gain) is reported in the derivative cash settlement (loss) gain line item on the condensed consolidated statements of cash flows within net cash provided by operating activities.

(2) Total derivative loss (gain) is reported in the derivative loss (gain) line item on the condensed consolidated statements of cash flows within cash provided by operating activities.

Credit Related Contingent Features

As of June 30, 2014, and through the filing date of this report, all of the Company’s derivative counterparties were members of the Company’s credit facility lender group. The Company’s obligations under its derivative contracts are secured by liens on at least 75 percent of the Company’s proved oil and gas properties.

Note 11 - Fair Value Measurements

The Company follows fair value measurement authoritative accounting guidance for all assets and liabilities measured at fair value. That authoritative accounting guidance defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Market or observable inputs are the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The fair value hierarchy for grouping these assets and liabilities is based on the significance level of the following inputs:

- Level 1 – quoted prices in active markets for identical assets or liabilities
- Level 2 – quoted prices in active markets for similar assets or liabilities, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations whose inputs are observable or whose significant value drivers are observable
- Level 3 – significant inputs to the valuation model are unobservable

The following is a listing of the Company's assets and liabilities that are measured at fair value and their classification within the fair value hierarchy as of June 30, 2014:

	Level 1 (in thousands)	Level 2	Level 3
Assets:			
Derivatives [1]	$—	$4,913	$—
Proved oil and gas properties [2]	$—	$—	$2,527
Unproved oil and gas properties [2]	$—	$—	$3,636
Oil and gas properties held for sale [2]	$—	$—	$6,466
Liabilities:			
Derivatives [1]	$—	$144,935	$—
Net Profits Plan [1]	$—	$—	$48,104

(1) This represents a financial asset or liability that is measured at fair value on a recurring basis.
(2) This represents a non-financial asset or liability that is measured at fair value on a nonrecurring basis.

The following is a listing of the Company's assets and liabilities that are measured at fair value and their classification within the fair value hierarchy as of December 31, 2013:

	Level 1 (in thousands)	Level 2	Level 3
Assets:			
Derivatives [1]	$—	$52,510	$—
Proved oil and gas properties [2]	$—	$—	$62,178
Unproved oil and gas properties [2]	$—	$—	$3,280
Oil and gas properties held for sale [2]	$—	$—	$650
Liabilities:			
Derivatives [1]	$—	$31,020	$—
Net Profits Plan [1]	$—	$—	$56,985

(1) This represents a financial asset or liability that is measured at fair value on a recurring basis.
(2) This represents a non-financial asset or liability that is measured at fair value on a nonrecurring basis.

Both financial and non-financial assets and liabilities are categorized within the above fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. The following is a description of the valuation methodologies used by the Company as well as the general classification of such instruments pursuant to the above fair value hierarchy.

Derivatives

The Company uses Level 2 inputs to measure the fair value of oil, gas, and NGL commodity derivatives. Fair values are based upon interpolated data. The Company derives internal valuation estimates taking into consideration the counterparties' credit ratings, the Company's credit rating, and the time value of money. These valuations are then compared to the respective counterparties' mark-to-market statements. These factors result in an estimated exit-price that management believes provides a reasonable and consistent methodology for valuing derivative instruments. The derivative instruments utilized by the Company are not considered by management to be complex, structured, or illiquid. The oil, gas, and NGL commodity derivative markets are highly active.

Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. However, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. The Company monitors the credit ratings of its counterparties and may require counterparties to post collateral if their ratings deteriorate. In some instances, the Company will attempt to novate the trade to a more stable counterparty.

Valuation adjustments are necessary to reflect the effect of the Company's credit quality on the fair value of any liability position with a counterparty. This adjustment takes into account any credit enhancements, such as collateral margin that the Company may have posted with a counterparty, as well as any letters of credit between the parties. The methodology to determine this adjustment is consistent with how the Company evaluates counterparty credit risk, taking into account the Company's credit rating, current credit facility margins, and any change in such margins since the last measurement date. All of the Company's derivative counterparties are members of the Company's credit facility lender group.

The methods described above may result in a fair value estimate that may not be indicative of net realizable value or may not be reflective of future fair values and cash flows. While the Company believes that the valuation methods utilized are appropriate and consistent with authoritative accounting guidance and with other marketplace participants, the Company recognizes that third parties may use different methodologies or assumptions to determine the fair value of certain financial instruments that could result in a different estimate of fair value at the reporting date.

Refer to Note 10 - Derivative Financial Instruments for more information regarding the Company's derivative instruments.

Net Profits Plan

The Net Profits Plan is a standalone liability for which there is no available market price, principal market, or market participants. The inputs available for this instrument are unobservable and are therefore classified as Level 3 inputs. The Company employs the income approach, which converts expected future cash flow amounts to a single present value amount. This technique uses the estimate of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk to calculate the fair value. There is a direct correlation between realized oil, gas, and NGL commodity prices driving net cash flows and the Net Profits Plan liability. Generally, higher commodity prices result in a larger Net Profits Plan liability and lower commodity prices result in a smaller Net Profits Plan liability.

The Company records the estimated fair value of the long-term liability for estimated future payments under the Net Profits Plan based on the discounted value of estimated future payments associated with each individual pool. The calculation of this liability is a significant management estimate. A discount rate of 12 percent is used to calculate this liability and is intended to represent the Company's best estimate of the present value of expected future payments under the Net Profits Plan.

The Company’s estimate of its liability is highly dependent on commodity prices, cost assumptions, discount rates, and overall market conditions. The Company regularly assesses the current market environment. The Net Profits Plan liability is determined using price assumptions of five one-year strip prices with the fifth year’s pricing then carried out indefinitely. The average price is adjusted for realized price differentials and to include the effects of the forecasted production covered by derivatives contracts in the relevant periods. The non-cash expense associated with this significant management estimate is highly volatile from period to period due to fluctuations that occur in the oil, gas, and NGL commodity markets.

If the commodity prices used in the calculation changed by five percent, the liability recorded at June 30, 2014, would differ by approximately $4 million. A one percent increase or decrease in the discount rate would result in a change of approximately $2 million. Actual cash payments to be made to participants in future periods are dependent on realized actual production, realized commodity prices, and costs associated with the properties in each individual pool of the Net Profits Plan. Consequently, actual cash payments are inherently different from the amounts estimated.

No published market quotes exist on which to base the Company's estimate of fair value of its Net Profits Plan liability. As such, the recorded fair value is based entirely on management estimates that are described within this footnote. While some inputs to the Company's calculation of fair value on the Net Profits Plan's future payments are from published sources, others, such as the discount rate and the expected future cash flows, are derived from the Company's own calculations and estimates.

The following table reflects the activity for the Company's Net Profits Plan liability measured at fair value using Level 3 inputs:

	For the Six Months Ended June 30, 2014	
	(in thousands)	
Beginning balance	$56,985	
Net increase in liability (1)	5,065	
Net settlements (1) (2)	(13,946	)
Transfers in (out) of Level 3	—	
Ending balance	$48,104	

(1) Net changes in the Company's Net Profits Plan liability are shown in the Change in Net Profits Plan liability line item of the accompanying statements of operations.

(2) Settlements represent cash payments made or accrued under the Net Profits Plan. The Company accrued or made cash payments under the Net Profits Plan of $8.5 million as a result of divestitures during the six months ended June 30, 2014.

Long-term Debt

The following table reflects the fair value of the Senior Notes measured using Level 1 inputs based on quoted secondary market trading prices. The Senior Notes were not presented at fair value on the accompanying balance sheets as of June 30, 2014, or December 31, 2013, as they are recorded at historical value.

	As of June 30, 2014	As of December 31, 2013
	(in thousands)	
2019 Notes	$370,563	$374,290
2021 Notes	$380,188	$373,625
2023 Notes	$432,792	$422,000
2024 Notes	$502,190	$475,315

As of June 30, 2014, the Company had no floating-rate debt outstanding.

Proved and Unproved Oil and Gas Properties

Proved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. The Company uses Level 3 inputs and the income valuation technique, which converts future amounts to a single present value amount, to measure the fair value of proved properties through an application of discount rates and price forecasts selected by the Company's management. The calculation of the discount rate is based on the best information available and was estimated to be 12 percent as of June 30, 2014, and December 31, 2013. The Company believes that the discount rate is representative of current market conditions and takes into account estimates of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk. The prices for oil and gas are forecasted based on New York Mercantile Exchange ("NYMEX") strip pricing, adjusted for basis differentials, for the first five years, after which a flat terminal price is used for each commodity stream. The prices for NGLs are forecasted using OPIS Mont Belvieu pricing, for as long as the market is actively trading, after which a flat terminal price is used. Future operating costs are also adjusted as deemed appropriate for these estimates. Proved properties classified as held for sale are valued using a market approach, based on an estimated selling price, as evidenced by the most current bid prices received from third parties. If an estimated selling price is not available, the Company utilizes the income valuation technique discussed above.

Unproved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. To measure the fair value of unproved properties, the Company uses a market approach, which takes into account the following significant assumptions: future development plans, risk weighted potential resource recovery, and estimated reserve values. Unproved properties classified as held for sale are valued using a market approach, based on an estimated selling price, as evidenced by the most current bid prices received from third parties. If an estimated selling price is not available, the Company estimates acreage value based on the price received for similar acreage in recent transactions by the Company or other market participants in the principal market.

Acquisitions of proved and unproved properties are measured at fair value as of the acquisition date using an income valuation technique similar to the Company's approach in measuring the fair value of proved and unproved properties, as discussed above. Due to the unobservable characteristics of the inputs, the fair value of acquired properties is considered Level 3 within the fair value hierarchy.

Asset Retirement Obligations

The Company utilizes the income valuation technique to determine the fair value of the asset retirement obligation liability at the point of inception by applying a credit-adjusted risk-free rate, which takes into account the Company's credit risk, the time value of money, and the current economic state, to the undiscounted expected abandonment cash flows. Given the unobservable nature of the inputs, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. There were no asset retirement obligations recorded at fair value in the accompanying balance sheets at June 30, 2014, or December 31, 2013.

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

This discussion and analysis contains forward-looking statements. Refer to Cautionary Information about Forward-Looking Statements at the end of this item for an explanation of these types of statements.

Overview of the Company, Highlights, and Outlook

General Overview

We are an independent energy company engaged in the acquisition, exploration, development, and production of oil, gas, and NGLs in onshore North America. Our assets include leading positions in the Eagle Ford shale and Bakken/Three Forks resource plays, oil-focused plays in the Powder River Basin and Permian Basin, and a position in an emerging play in East Texas. We have built a portfolio of onshore properties in the contiguous United States primarily through early entry into existing and emerging resource plays. This portfolio is comprised of properties with established production and reserves, prospective drilling opportunities, and unconventional resource prospects. We believe our strategy provides for stable and predictable production and reserves growth. Furthermore, by entering these plays early, we believe we can capture larger resource potential at a lower cost.

Our principal business strategy is to focus on the early capture of resource plays in order to create and then enhance value for our stockholders while maintaining a strong balance sheet. We strive to leverage industry-leading exploration and leasehold acquisition teams to quickly acquire and test new resource play concepts at a reasonable cost. Once we have identified potential value through these efforts, our goal is to develop such potential through top-tier operational and project execution, and as appropriate, high-grade our portfolio by selectively divesting assets. We regularly examine our portfolio for opportunities to improve the quality of our asset base in order to optimize our returns and preserve our financial strength.

In the second quarter of 2014, we had the following financial and operational results:

- Average net daily production for the three months ended June 30, 2014, was 42.8 MBbls of oil, 417.2 MMcf of gas, and 34.7 MBbls of NGLs, for a Company record quarterly equivalent daily production rate of 147.0 MBOE, compared with 131.8 MBOE for the same period in 2013. Please see additional discussion below under Production Results.

- Net income for the three months ended June 30, 2014, was $59.8 million, or $0.88 per diluted share, compared to net income for the three months ended June 30, 2013, of $76.5 million, or $1.13 per diluted share. Please refer to the Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2014, and 2013 below for additional discussion regarding the components of net income.

- Costs incurred for oil and gas property acquisitions and exploration and development activities for the three months ended June 30, 2014, totaled $677.4 million, which includes approximately $100.0 million related to non-producing property acquisitions in the Powder River Basin. The majority of our drilling and completion costs incurred during this period were in our Eagle Ford shale and Bakken/Three Forks programs. Total costs incurred for the same period in 2013 were $500.3 million. Please refer to Overview of Liquidity and Capital Resources below for additional discussion on how we expect to fund our capital program.

- Adjusted EBITDAX, a non-GAAP financial measure, for the three months ended June 30, 2014, was a Company quarterly record of $423.4 million, compared to $342.5 million for the same period in 2013. Please refer to Non-GAAP Financial Measures below for additional discussion, including our definition of adjusted EBITDAX and reconciliations of our GAAP net income and net cash provided by operating activities to adjusted EBITDAX.

Oil, Gas, and NGL Prices

Our financial condition and the results of our operations are significantly affected by the prices we receive for our oil, gas, and NGL production, which can fluctuate dramatically. We sell the majority of our gas under contracts using first-of-the-month index pricing, which means gas produced in a given month is sold at the first-of-the-month price regardless of the spot price on the day the gas is produced. For assets where high BTU gas is sold at the wellhead, we also receive additional value for the high energy content contained in the gas stream. Our NGL production is generally sold using contracts paying us a monthly average of the posted OPIS daily settlement prices, adjusted for processing, transportation, and location differentials. Our oil and condensate are sold using contracts paying us various industry posted prices, most commonly NYMEX West Texas Intermediate ("WTI"). We are paid the average of the daily settlement price for the respective posted prices for the period in which the product is sold, adjusted for quality, transportation, American Petroleum Institute ("API") gravity, and location differentials. Substantially all of our oil production in our South Texas & Gulf Coast region is condensate. When we refer to realized oil, gas, and NGL prices below, the disclosed price represents the average price for the respective period, before the effects of derivative cash settlements, unless otherwise indicated.

The following table summarizes commodity price data, as well as the effects of derivative cash settlements as further discussed under the caption Derivative Activity below, for the first and second quarters of 2014, as well as the second quarter of 2013:

	For the Three Months Ended		
	June 30, 2014	March 31, 2014	June 30, 2013
Crude Oil (per Bbl):			
Average daily NYMEX price	$103.06	$98.65	$94.14
Realized price, before the effects of derivative cash settlements	$91.78	$88.96	$90.00
Effects of derivative cash settlements	$(5.18)	$(1.85)	$(0.36)
Natural Gas:			
Average daily NYMEX price (per MMBtu)	$4.59	$5.16	$4.02
Realized price, before the effects of derivatives cash settlements (per Mcf)	$4.87	$5.22	$4.28
Effects of derivative cash settlements (per Mcf)	$(0.36)	$(0.38)	$(0.05)
Natural Gas Liquids (per Bbl):			
Average daily OPIS price	$41.21	$45.61	$37.76
Realized price, before the effects of derivative cash settlements	$35.61	$38.79	$34.09
Effects of derivative cash settlements	$(0.02)	$(3.03)	$1.91

Note: Average OPIS prices per barrel of NGL, historical or strip, are based on a product mix of 37% Ethane, 32% Propane, 6% Isobutane, 11% Normal Butane, and 14% Natural Gasoline for all periods presented. This product mix represents the industry standard composite barrel and does not necessarily represent our product mix for NGL production. Realized prices reflect our actual product mix.

While quoted NYMEX oil and gas and OPIS NGL prices are generally used as a basis for comparison within our industry, the prices we receive are affected by quality, energy content, location, and transportation differentials for these products.

We expect future prices for oil, gas, and NGLs to be volatile. In addition to supply and demand fundamentals, as a global commodity, the price of oil will continue to be impacted by real or perceived geopolitical risks in oil producing regions of the world, particularly the Middle East. The relative strength of the U.S. dollar compared to other currencies could affect the price of oil. The supply of NGLs in the United States is expected to continue to grow in the near term as a result of the number of industry participants targeting projects that produce these products. If demand does not keep pace with anticipated growth in NGL supply, prices could be negatively impacted. The prices of several NGL products correlate to the price of oil and accordingly are likely to directionally follow that market. Gas prices have been under sustained downward pressure due to high levels of supply in recent years, particularly in the Northeast United States, although cold weather during winter months provided a near term increase in pricing in early 2014. Longer term, we anticipate natural gas prices will remain near current levels. Changes to existing laws and regulations pertaining to the ability to export oil, gas, and NGLs also has the potential to impact the prices for these commodities. The following table summarizes 12-month strip prices for NYMEX WTI oil, NYMEX Henry Hub gas, and OPIS NGLs (same product mix as discussed under the table above) as of July 23, 2014, and June 30, 2014:

	As of July 23, 2014	As of June 30, 2014
NYMEX WTI oil (per Bbl)	$ 98.56	$ 101.10
NYMEX Henry Hub gas (per MMBtu)	$ 3.83	$ 4.35
OPIS NGLs (per Bbl)	$ 39.95	$ 41.10

Derivative Activity

We use financial derivative instruments as part of our financial risk management program. We have a financial risk management policy governing our use of derivatives. The amount of our production covered by derivatives is driven by the amount of debt on our balance sheet and the level of capital commitments and long-term obligations we have in place. With our current derivative contracts, we believe we have established a base cash flow stream for our future operations and have partially reduced our exposure to volatility in commodity prices. Our use of costless collars for a portion of our derivatives allows us to participate in some of the upward movements in oil, gas, and NGL prices while also setting a price floor for a portion of our production. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional information regarding our oil, gas, and NGL derivatives.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (“Dodd-Frank Act”) included provisions requiring over-the-counter derivative transactions to be cleared through clearinghouses and traded on exchanges. On July 10, 2012, the Commodity Futures Trading Commission (“CFTC”) and the SEC adopted final joint rules under Title VII of the Dodd-Frank Act, which define certain terms that determine what types of transactions will be subject to regulation under the Dodd-Frank Act swap rules. The issuance of these final rules also triggers compliance dates for a number of other final Dodd-Frank Act rules, including new rules proposed by the CFTC governing margin requirements for uncleared swaps entered into by non-bank swap entities, and new rules proposed by U.S. banking regulators regarding margin requirements for uncleared swaps entered into by bank swap entities. The ultimate effect of these new rules on our business and any additional regulations is currently uncertain. Under CFTC rules we believe our derivative activity qualifies for the non-financial, commercial end-user exception, which exempts derivatives intended to hedge or mitigate commercial risk entered into by entities predominantly engaged in non-financial activity from the mandatory swap clearing requirement. However, we are not certain whether the provisions of the final rules and regulations will exempt us from the requirements to post margin in connection with commodity price risk management activities. Final rules and regulations on major provisions of the legislation, such as new margin requirements, are to be established through regulatory rulemaking. Although we cannot predict the ultimate outcome of these rulemakings, new rules and regulations in this area may result in increased costs and cash collateral requirements for the types of derivative instruments we use to manage our financial risks related to volatility in oil, gas, and NGL commodity prices.

Second Quarter 2014 Highlights and Outlook for the Remainder of 2014

Operational Activities. During the second quarter of 2014, in our operated Eagle Ford shale program in South Texas, we operated five drilling rigs supported by two frac spreads. We were primarily focused on pad drilling in the northern portion of our acreage position where there is a higher liquids contribution to our product mix. Our remaining 2014 program will include various tests of well drilling and completion designs intended to enhance well performance and capital efficiency. We have shifted to drilling longer lateral wells and completing these wells with higher sand concentrations. We believe we have secured the requisite services, such as gas pipeline takeaway capacity and drilling and completion services, to support our current development plans.

In our outside operated Eagle Ford shale program, the operator began the second quarter of 2014 running 10 drilling rigs and dropped a rig by the end of the quarter. During the quarter, the remainder of our carry under our Acquisition and Development Agreement with Mitsui E&P Texas LP (“Mitsui”), an indirect subsidiary of Mitsui & Co., Ltd. (the “Acquisition and Development Agreement”), was expended. After completion of the carry, we began paying our full share of drilling and completion costs.

We have an ongoing exploration program to acquire leasehold and test concepts in new plays. In 2014, we are evaluating an emerging new venture play in East Texas. We expect to construct a gathering system later in 2014 to allow for longer-term production tests on wells we have drilled and completed.

In our Bakken/Three Forks program, we operated three drilling rigs during the second quarter of 2014 focusing on infill drilling of our Raven/Bear Den and Gooseneck prospects in the North Dakota portion of the Williston Basin. We plan to monitor the results of various well and completion designs and down-spacing tests of both our operated and non-operated properties throughout 2014. Additionally, we plan to test the Bakken interval on our Gooseneck and Stateline acreage during the year. Subsequent to June 30, 2014, we entered into an agreement to acquire approximately 61,000 net acres adjacent to our Gooseneck prospect for approximately $330.0 million.
We have been building and accelerating activity in our emerging play in the Powder River Basin in Wyoming throughout 2014. During the second quarter of 2014, we closed on previously announced acquisitions for total cash consideration of approximately $100.0 million. We also added a third drilling rig during the quarter to accelerate the delineation of the play, and we plan to add a fourth operated drilling rig in the third quarter.
In our Permian program, we operated two drilling rigs during the second quarter of 2014 focused on horizontal testing and development of the Wolfcamp B interval in our Sweetie Peck prospect. At the end of the second quarter, we spud our first Wolfcamp D test in our Buffalo prospect in the northern Midland Basin. We have approximately 130,000 net acres in the Permian region.

Please refer to Overview of Liquidity and Capital Resources below for additional discussion regarding how we intend to fund our 2014 capital program.
Production Results. The table below provides a regional breakdown of our production for the second quarter of 2014:

	South Texas & Gulf Coast	Rocky Mountain	Permian	Mid-Continent	Total [1]
Oil (MMBbl)	1.7	1.7	0.5	—	3.9
Gas (Bcf)	30.3	1.5	1.1	5.0	38.0
NGLs (MMBbl)	3.1	—	—	0.1	3.2
Equivalent (MMBOE)	9.9	2.0	0.7	0.9	13.4
Avg. daily equivalents (MBOE/d)	108.3	21.6	7.5	9.7	147.0
Relative percentage	74 %	15 %	5 %	6 %	100 %

[1] Totals may not add due to rounding.

Our production in the second quarter of 2014 was primarily driven by the continued development of our operated and non-operated Eagle Ford shale programs in our South Texas & Gulf Coast region. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2014, and 2013 below for additional discussion on production.

Rocky Mountain Divestiture. In the second quarter of 2014, we completed the divestiture of certain non-strategic assets in the Williston Basin located in our Rocky Mountain region that were classified as held for sale at March 31, 2014. Total divestiture proceeds were $50.2 million. The estimated net gain on this divestiture was $27.8 million. This divestiture is subject to normal post-closing adjustments, which are expected to be completed during the second half of 2014.

Subsequent Events. Subsequent to June 30, 2014, we entered into multiple agreements to acquire producing and non-producing properties in our Rocky Mountain region for a total of approximately $345.0 million. Additionally, we entered into derivative contracts for a total of 4.2 million Bbls of oil production that extend through 2016.

First Six Months of 2014 Highlights

Production Results. The table below provides a regional breakdown of our first six months of 2014 production:

	South Texas & Gulf Coast	Rocky Mountain	Permian	Mid-Continent	Total [(1)]
Oil (MMBbl)	3.3	3.3	0.9	—	7.5
Gas (Bcf)	58.6	3.0	2.1	9.7	73.5
NGLs (MMBbl)	6.0	—	—	0.1	6.1
Equivalent (MMBOE)	19.0	3.9	1.3	1.7	25.9
Avg. daily equivalents (MBOE/d)	105.0	21.3	7.1	9.4	142.8
Relative percentage	73 %	15 %	5 %	7 %	100 %

(1) Totals may not add due to rounding.

Please refer to Second Quarter 2014 Highlights and Outlook for the Remainder of 2014 above and Comparison of Financial Results and Trends Between the Six Months Ended June 30, 2014, and 2013 below for additional discussion on production.

Costs Incurred in Oil and Gas Producing Activities. For the six months ended June 30, 2014, we incurred $1.0 billion in costs related to oil and gas property acquisitions and exploration and development activities, including both capitalized and expensed amounts. This amount includes approximately $100.0 million related to non-producing property acquisitions in the Powder River Basin. The majority of drilling and completion costs incurred during this period were in our Eagle Ford shale and Bakken/Three Forks programs. Please refer to Overview of Liquidity and Capital Resources below for additional discussion on how we expect to fund our capital program.

Financial Results of Operations and Additional Comparative Data

The table below provides information regarding selected production and financial information for the quarter ended June 30, 2014, and the immediately preceding three quarters. Additional details of per BOE costs are presented later in this section.

	For the Three Months Ended			
	June 30, 2014	March 31, 2014	December 31, 2013	September 30, 2013
	(in millions)			
Production (MMBOE)	13.4	12.5	13.2	12.8
Oil, gas, and NGL production revenue	$654.7	$623.1	$593.7	$601.8
Lease operating expense	$62.8	$57.0	$61.1	$61.0
Transportation costs	$83.0	$79.2	$75.0	$68.8
Production taxes	$31.8	$27.5	$26.7	$29.1
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$187.8	$177.2	$202.6	$195.8
Exploration	$24.3	$21.3	$21.8	$16.3
General and administrative	$38.1	$35.1	$48.0	$33.9
Net income	$59.8	$65.6	$7.0	$70.7

Selected Performance Metrics:

	For the Three Months Ended			
	June 30, 2014	March 31, 2014	December 31, 2013	September 30, 2013
Average net daily production equivalent (MBOE/d)	147.0	138.6	143.8	138.8
Lease operating expense (per BOE)	$4.69	$4.58	$4.62	$4.77
Transportation costs (per BOE)	$6.20	$6.35	$5.67	$5.38
Production taxes as a percent of oil, gas, and NGL production revenue	4.9 %	4.4 %	4.5 %	4.8 %
Depletion, depreciation, amortization, and asset retirement obligation liability accretion (per BOE)	$14.03	$14.21	$15.31	$15.33
General and administrative (per BOE)	$2.85	$2.81	$3.63	$2.66

Note: Amounts may not recalculate due to rounding.

A three-month and six-month overview of selected production and financial information, including trends:

	For the Three Months Ended June 30, 2014	2013	Amount Change Between Periods	Percent Change Between Periods	For the Six Months Ended June 30, 2014	2013	Amount Change Between Periods	Percent Change Between Periods
Net production volumes [1]								
Oil (MMBbl)	3.9	3.2	0.7	21 %	7.5	6.4	1.2	19 %
Gas (Bcf)	38.0	39.1	(1.2)	(3)%	73.5	71.4	2.1	3 %
NGLs (MMBbl)	3.2	2.2	0.9	41 %	6.1	4.1	2.0	48 %
Equivalent (MMBOE)	13.4	12.0	1.4	12 %	25.9	22.3	3.5	16 %
Average net daily production [1]								
Oil (MBbl per day)	42.8	35.5	7.3	21 %	41.7	35.1	6.6	19 %
Gas (MMcf per day)	417.2	430.2	(13.1)	(3)%	406.1	394.4	11.7	3 %
NGLs (MBbl per day)	34.7	24.6	10.1	41 %	33.4	22.5	10.9	48 %
Equivalent (MBOE per day)	147.0	131.8	15.3	12 %	142.8	123.4	19.4	16 %
Oil, gas, & NGL production revenue (in millions)								
Oil production revenue	$357.3	$290.6	$ 66.7	23 %	$682.6	$577.7	$ 104.9	18 %
Gas production revenue	184.9	167.6	17.3	10 %	370.5	282.6	87.9	31 %
NGL production revenue	112.5	76.3	36.2	47 %	224.7	143.8	80.9	56 %
Total	$654.7	$534.5	$ 120.2	22 %	$1,277.8	$1,004.1	$ 273.7	27 %
Oil, gas, & NGL production expense (in millions)								
Lease operating expense	$62.8	$56.2	$ 6.6	12 %	$119.8	$110.9	$ 8.9	8 %
Transportation costs	83.0	67.0	16.0	24 %	162.2	114.4	47.8	42 %
Production taxes	31.8	26.5	5.3	20 %	59.3	50.1	9.2	18 %
Total	$177.6	$149.7	$ 27.9	19 %	$341.3	$275.4	$ 65.9	24 %
Realized price								
Oil (per Bbl)	$91.78	$90.00	$ 1.78	2 %	$90.41	$90.82	$ (0.41)	— %
Gas (per Mcf)	$4.87	$4.28	$ 0.59	14 %	$5.04	$3.96	$ 1.08	27 %
NGLs (per Bbl)	$35.61	$34.09	$ 1.52	4 %	$37.13	$35.24	$ 1.89	5 %
Per BOE	$48.93	$44.57	$ 4.36	10 %	$49.43	$44.95	$ 4.48	10 %
Per BOE Data [1]								
Production costs:								
Lease operating expense	$4.69	$4.69	$ —	— %	$4.64	$4.96	$ (0.32)	(6)%
Transportation costs	$6.20	$5.59	$ 0.61	11 %	$6.27	$5.12	$ 1.15	22 %
Production taxes	$2.38	$2.21	$ 0.17	8 %	$2.29	$2.24	$ 0.05	2 %
General and administrative	$2.85	$2.95	$ (0.10)	(3)%	$2.83	$3.03	$ (0.20)	(7)%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$14.03	$18.82	$ (4.79)	(25)%	$14.12	$19.00	$ (4.88)	(26)%
Derivative cash settlement [2]	$(2.52)	$0.09	$ (2.61)	(2,900)%	$(2.43)	$0.57	$ (3.00)	(526)%
Earnings per share information								
Basic net income per common share	$0.89	$1.15	$ (0.26)	(23)%	$1.87	$1.41	$ 0.46	33 %
Diluted net income per common share	$0.88	$1.13	$ (0.25)	(22)%	$1.84	$1.38	$ 0.46	33 %
	67,069	66,295	774	1 %	67,063	66,254	809	1 %

Basic weighted-average common shares outstanding (in thousands)									
Diluted weighted-average common shares outstanding (in thousands)	68,239	67,893	346	1 %	68,180	67,711	469	1 %

(1) Amounts and percentage changes may not recalculate due to rounding.
(2) We discontinued hedge accounting on January 1, 2011. As a result, fair values at December 31, 2010, were frozen in AOCL and were reclassified into earnings as the original derivative transactions settled, the last of which settled in the third quarter of 2013. For the three and six months ended June 30, 2013, derivative cash settlements are included within the other operating revenues and derivative loss (gain) line items in the accompanying statements of operations. All derivative cash settlements for the three and six months ended June 30, 2014, are included within the derivative loss (gain) line item only.

We present per BOE information because we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe may require additional analysis. Average daily reported production for the three and six months ended June 30, 2014, increased 12 percent and 16 percent, respectively, compared with the same periods in 2013, driven primarily by the development of our Eagle Ford shale assets. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2014, and 2013 below for additional discussion on changes in our production mix in 2014.

Changes in production volumes, revenues, and costs reflect the cyclical and highly volatile nature of our industry. Our realized price on a per BOE basis increased 10 percent for the three and six months ended June 30, 2014, compared to the same periods in 2013, primarily due to higher natural gas prices.

Lease operating expenses ("LOE") on a per BOE basis for the three and six months ended June 30, 2014, remained flat and decreased six percent, respectively, compared to the same periods in 2013. Our LOE is comprised of recurring LOE, workover expense, and ad valorem tax expense. Absolute LOE increased 12 percent and eight percent for the three and six months ended June 30, 2014, respectively, compared to the same periods in 2013, driven primarily by increased workover activity in our Rocky Mountain region and higher ad valorem tax expense on our properties in Texas. On a per BOE basis, recurring LOE declined as production grew at a faster rate than absolute recurring LOE. We experience volatility in our LOE as a result of seasonality in workover expense and the impact industry activity has on service provider costs. We expect recurring LOE per BOE to remain stable for the remainder of this year based on our view of the services market and our production outlook.

Transportation costs on a per BOE basis for the three and six months ended June 30, 2014, increased 11 percent and 22 percent, respectively, compared to the same periods in 2013. Our Eagle Ford shale program has meaningfully higher transportation expense per unit of production compared to our other regions. Ongoing development of the Eagle Ford shale has resulted in these assets becoming a larger portion of our total production, thereby increasing company-wide transportation expense per BOE over time. The run-rate of our per unit transportation cost in our Eagle Ford shale program has increased in recent quarters due to incremental compression charges and increased variable fuel costs associated with higher natural gas prices. We anticipate we will recognize fluctuations in our per unit Eagle Ford shale transportation run-rate over time; however, we also anticipate company-wide transportation costs on a per BOE basis to increase as Eagle Ford shale production continues to grow and constitutes a larger portion of our total production mix.

Production taxes on a per BOE basis for the three and six months ended June 30, 2014, increased eight percent and two percent, respectively, compared to the same periods in 2013. We generally expect production tax expense to trend with oil, gas, and NGL production revenue, although changes in our total production mix can impact production taxes on a per BOE basis as well as different state tax incentives offered based on current regulations and the type of the wells drilled.

G&A expense on a per BOE basis for the three and six months ended June 30, 2014, decreased three percent and seven percent, respectively, compared to the same periods in 2013. Absolute G&A expense increased between these two periods due to an increase in employee headcount; however, production increased at a faster rate than our G&A expense thereby reducing G&A on a per BOE basis. A portion of our G&A expense is linked to our profitability and cash flow, which are driven in large part by the realized commodity prices we receive for our production. The Net Profits Plan and a portion of our short-term incentive compensation correlate with net cash flows and therefore are subject to variability. Generally, we expect G&A expense on a per BOE basis to decrease, as we anticipate production will continue to increase at a faster rate than our increase in absolute G&A expense.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion ("DD&A") expense on a per BOE basis for the three and six months ended June 30, 2014, decreased 25 percent and 26 percent, respectively, compared to the same periods in 2013. Our DD&A rate can fluctuate as a result of impairments, planned and closed divestitures, and changes in the mix of our production and the underlying proved reserve volumes. Our DD&A rate has decreased as assets with lower finding and development costs have become a larger portion of our total production mix. Our finding and development costs have benefited from a general decrease in well costs and an increase in recoveries per well, as well as from our outside operated Eagle Ford shale program, where we have added reserves with minimal associated costs due to our carry with Mitsui under our Acquisition and Development Agreement, which was exhausted during the second quarter of 2014.

Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2014, and 2013 and Comparison of Financial Results and Trends Between the Six Months Ended June 30, 2014, and 2013 below for additional discussion on oil, gas, and NGL production expense, DD&A expense, and G&A expense.
Please refer to Note 9 - Earnings per Share in Part I, Item 1 of this report for additional discussion on the types of shares included in our basic and diluted net income per common share calculations.

Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2014, and 2013

Oil, gas, and NGL production revenue. The following table presents the regional changes in our production, and oil, gas, and NGL production revenue and costs between the three months ended June 30, 2014, and 2013:

	Average Net Daily Production Added (Lost) (MBOE/d)	Oil, Gas, & NGL Production Revenue Added (Lost) (in millions)	Production Costs Increase (Decrease) (in millions)
South Texas & Gulf Coast	23.7	$116.1	$22.2
Rocky Mountain	1.8	21.8	8.3
Permian	0.9	6.8	1.0
Mid-Continent	(11.1)	(24.5)	(3.6)
Total	15.3	$120.2	$27.9

In our South Texas & Gulf Coast region, average net daily production increased 28 percent between the two periods as a result of drilling activity in our Eagle Ford shale program. This significant production growth in our Eagle Ford shale program exceeded the production decrease in our Mid-Continent region resulting from our Anadarko Basin asset divestiture in December 2013.

A 12 percent increase in production on a BOE basis combined with a 10 percent increase in the realized price per BOE resulted in a 22 percent increase in oil, gas, and NGL production revenue between the two periods. Please refer to A three-month and six-month overview of selected production and financial information, including trends above for realized prices received before the effects of derivative cash settlements for the three months ended June 30, 2014, and 2013. Based on current levels of activity, we expect production volumes to continue to increase. We expect our realized prices to trend with commodity prices.

Other operating revenues. Gains and losses on divestiture activity are recorded to other operating revenues. The gain realized on the sale of properties in our Rocky Mountain region during the second quarter of 2014 was mostly offset by a loss recorded on assets classified as held for sale. Please refer to Second Quarter 2014 Highlights and Outlook for the Remainder of 2014 above for further discussion of the gain recorded on our divestiture of assets in our Rocky Mountain region. Other operating revenues also includes marketed gas system revenues, which decreased in 2014 as a result of our Anadarko Basin divestiture in December 2013, which reduced marketed gas volumes and the overall significance of marketed gas revenue and expense. Partially offsetting this decrease was a $10.7 million gain recorded in the second quarter of 2014 related to our settlement with Endeavour.

Oil, gas, and NGL production expense. Total production costs increased 19 percent for the three months ended June 30, 2014, compared with the same period of 2013, as a result of a 12 percent increase in net equivalent production volumes as well as an overall increase in transportation costs in our South Texas & Gulf Coast region. Please refer to A three-month and six-month overview of selected production and financial information, including trends above for discussion of production costs on a per BOE basis.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A expense decreased 17 percent for the three-month period ended June 30, 2014, compared with the same period in 2013. Please refer to A three-month and six-month overview of selected production and financial information, including trends above for discussion of DD&A on a per BOE basis.

Exploration. The components of exploration expense are summarized as follows:

	For the Three Months Ended June 30,	
	2014	2013
	(in millions)	
Geological and geophysical expenses	$1.7	$0.8
Exploratory dry hole expense	6.5	5.7
Overhead and other expenses	16.1	14.2
Total	$24.3	$20.7

Exploration expense for the three months ended June 30, 2014, increased 17 percent compared to the same period in 2013 as a result of higher overhead costs. During the second quarters of 2014 and 2013, we expensed $6.5 million and $5.7 million, respectively, to exploratory dry hole expense due to wells deemed to be non-commercial. An exploratory project resulting in non-commercial quantities of oil, gas, or NGLs is deemed an exploratory dry hole and impacts the amount of exploration expense we record. As long as we have an ongoing exploration program, we have the potential to recognize expense associated with exploratory dry holes.

Impairment of proved properties. We recorded no impairment of proved properties for the three months ended June 30, 2014. We recorded a $34.6 million impairment of proved properties in the second quarter of 2013, related to our decision to no longer pursue the development of certain underperforming assets. We expect impairments of proved properties to be more likely to occur in periods of low commodity prices.

Abandonment and impairment of unproved properties. We recorded minimal abandonment and impairment of unproved properties expense for the three months ended June 30, 2014. We expensed $4.3 million for the same period of 2013, related to acreage we no longer intended to develop. We expect our abandonment and impairment of unproved properties to trend with any lease expirations. Unsuccessful exploratory activities may also result in impairments of unproved properties.

General and administrative. G&A expense increased eight percent for the three months ended June 30, 2014, compared with the same period of 2013. The increase is due to an increase in employee headcount, which increased overall compensation and benefits expense. Please refer to A three-month and six-month overview of selected production and financial information, including trends above for discussion of G&A expense on a per BOE basis.

Change in Net Profits Plan liability. This non-cash expense generally relates to the change in the estimated value of the associated noncurrent liability between reporting periods. For the three months ended June 30, 2014, and 2013, we recorded a non-cash benefit of $7.1 million and $5.4 million, respectively. The change in our liability is subject to estimation and may change from period to period based on assumptions used for production rates, reserve quantities, commodity pricing, discount rates, and production costs. We expect the change in our Net Profits Plan liability to correlate with fluctuations in commodity prices. Payments made to participants as a result of divestitures and ongoing operations also impact the change in the Net Profits Plan liability.

Derivative loss (gain). We recognized a derivative loss of $126.5 million for the three-month period ended June 30, 2014, which is comprised of a $33.7 million loss on cash settlements and a $92.8 million decrease in the fair value of commodity derivative contracts during the period. This compares to a gain of $85.2 million for the same period in 2013, which is comprised of an $83.0 million increase in the fair value of commodity derivative contracts and a $2.2 million gain on cash settlements during the period. The increase in commodity strip prices in the three months ended June 30, 2014, resulted in a less favorable derivative position, while the decrease in prices during the comparable period in 2013 resulted in a more favorable position. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional information.

Other operating expenses. This line item includes marketed gas system expense, which decreased in the first half of 2014 as a result of our Anadarko Basin divestiture in December 2013, reducing marketed gas volumes and the overall significance of marketed gas revenue and expense. Additionally, for the three months ended June 30, 2013, other operating expenses included $14.2 million of expense related to an agreed clarification concerning royalty payment provisions of various leases on certain South Texas & Gulf Coast acreage.

Income tax expense. We recorded income tax expense of $36.0 million for the three-month period ended June 30, 2014, compared to expense of $46.2 million for the same period in 2013. The effective rate for both periods was 37.6 percent.

Comparison of Financial Results and Trends Between the Six Months Ended June 30, 2014, and 2013

Oil, gas, and NGL production revenue. The following table presents the regional changes in our production, and oil, gas, and NGL production revenue and costs between the six months ended June 30, 2014, and 2013:

	Average Net Daily Production Added (Lost) (MBOE/d)	Oil, Gas, & NGL Production Revenue Added (Lost) (in millions)	Production Costs Increase (Decrease) (in millions)
South Texas & Gulf Coast	28.3	$262.4	$54.9
Rocky Mountain	2.2	45.4	15.6
Permian	1.2	20.3	2.8
Mid-Continent	(12.3)	(54.4)	(7.4)
Total	19.4	$273.7	$65.9

Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2014, and 2013 above for additional discussion regarding the above trends.

In our South Texas & Gulf Coast region, average net daily production increased 37 percent between the two periods as a result of drilling activity in our Eagle Ford shale program. This significant production growth in our Eagle Ford shale program exceeded the production decrease in our Mid-Continent region resulting from our Anadarko Basin asset divestiture in December 2013.

A 16 percent increase in production on a BOE basis combined with a 10 percent increase in the realized price per BOE resulted in a 27 percent increase in oil, gas, and NGL production revenue between the two periods.

Other operating revenues. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2014, and 2013 above for additional discussion.

Oil, gas, and NGL production expense. Total production costs increased 24 percent for the six months ended June 30, 2014, compared with the same period of 2013, as a result of a 16 percent increase in net equivalent production volumes as well as an overall increase in transportation costs in our South Texas & Gulf Coast region. Please refer to the caption A three-month and six-month overview of selected production and financial information, including trends above for discussion of production costs on a per BOE basis.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A expense decreased 14 percent to $365.0 million for the six-month period ended June 30, 2014, compared with $424.4 million for the same period in 2013. Please refer to A three-month and six-month overview of selected production and financial information, including trends above for discussion of DD&A on a per BOE basis.

Exploration. The components of exploration expense are summarized as follows:

	For the Six Months Ended June 30,	
	2014	2013
	(in millions)	
Geological and geophysical expenses	$5.8	$2.3
Exploratory dry hole expense	6.5	5.9
Overhead and other expenses	33.3	27.9
Total	$45.6	$36.1

Exploration expense for the six months ended June 30, 2014, increased 26 percent compared to the same period in 2013 as a result of a seismic study performed in the first quarter of 2014 and an increase in exploration overhead. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2014, and 2013 above for additional discussion.

Impairment of proved properties. We recorded no impairment of proved properties expense for the six months ended June 30, 2014, compared to $55.8 million for the same period in 2013. In addition to the discussion under Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2014, and 2013, above, we recorded a $21.2 million impairment of proved properties in the first quarter of 2013 related to Olmos interval, dry gas assets in our South Texas & Gulf Coast region as a result of a plugging and abandonment program.
Abandonment and impairment of unproved properties. For the six months ended June 30, 2014, and 2013, we recorded abandonment and impairment expense of $3.0 million and $4.6 million, respectively, related to acreage we no longer intended to develop. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2014, and 2013 above for additional discussion.

General and administrative. G&A expense increased eight percent to $73.2 million for the six months ended June 30, 2014, compared with $67.7 million for the same period of 2013. Please refer to A three-month and six-month overview of selected production and financial information, including trends and Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2014, and 2013 above for additional discussion.
Change in Net Profits Plan liability. For the six months ended June 30, 2014, and 2013, we recorded a non-cash benefit of $8.9 million and $7.4 million, respectively. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2014, and 2013 above for additional discussion.

Derivative loss (gain). We recognized a derivative loss of $224.1 million for the six-month period ended June 30, 2014, which is comprised of a $62.6 million loss on cash settlements and a $161.5 million decrease in the fair value of commodity derivative contracts during the period. This compares to a gain of $54.6 million for the same period in 2013, which is comprised of a $14.0 million gain on cash settlements and a $40.6 million increase in the fair value of commodity derivative contracts during the period. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2014, and 2013 above for additional discussion.

Other operating expenses. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2014, and 2013 above for additional discussion.

Income tax expense. We recorded income tax expense of $74.9 million for the six-month period ended June 30, 2014, compared to expense of $56.6 million for the same period in 2013, resulting in effective tax rates of 37.4 percent and 37.8 percent, respectively. The decrease in the rate is partially attributable to the Anadarko Basin divestiture that closed at the end of 2013. The sale of assets in a higher rate state caused a decrease in the composition of our blended state tax rate for future years. However, state cash taxes are higher as a result of estimated Texas margin tax.

Overview of Liquidity and Capital Resources

We believe we have sufficient liquidity and capital resources to execute our business plan for the foreseeable future. We continue to manage the duration and level of our drilling and completion service commitments in order to provide flexibility to reduce activity and capital expenditures in periods of prolonged commodity price decline.

Sources of Cash

We currently expect our remaining 2014 capital program to be funded by cash flows from operations and proceeds from 2013 and 2014 divestitures, with any shortfall to be funded by borrowings under our credit facility. Although we anticipate cash flow from these sources will be sufficient to fund our remaining expected 2014 capital program, we may also elect to access the capital markets, depending on prevailing market conditions, as well as divest of non-strategic oil and gas properties to provide an additional source of funding. From time to time, we may enter into carrying cost funding and sharing arrangements with third parties for particular exploration and/or development programs. All of our sources of liquidity can be impacted by the general condition of the broader economy and by fluctuations in commodity prices, operating costs, and volumes produced, all of which affect us and our industry. We have no control over the market prices for oil, gas, or NGLs, although we are able to influence the amount of our realized revenues from our oil, gas, and NGL sales through the use of derivative contracts as part of our commodity price risk management program. Historically, decreases in commodity prices have limited our industry's access to capital markets. The borrowing base under our credit facility could be reduced as a result of lower commodity prices, divestitures of proved properties, or newly issued debt.

In late 2011, we consummated our Acquisition and Development Agreement with Mitsui, pursuant to which Mitsui funded, or carried, 90 percent of certain drilling and completion costs attributable to our remaining interest in our non-operated Eagle Ford shale acreage until $680.0 million was expended on our behalf. The remaining carry was realized during the second quarter of 2014, at which point we became responsible for funding our share of drilling and completion costs.

Proposals to reform the IRC and discussions regarding funding the federal government budget include eliminating or reducing current tax deductions for intangible drilling costs, depreciation of equipment acquisition costs, the domestic production activities deduction, and percentage depletion. We expect that legislation modifying or eliminating these deductions would reduce net operating cash flows over time, thereby reducing funding available for our exploration and development capital programs, as well as funding available to our peers in the industry. If enacted, these funding reductions could have a significant adverse effect on drilling in the United States for a number of years.

Credit Facility

During the second quarter of 2013, we and our lenders entered into a Fifth Amended and Restated Credit Agreement. The credit facility has a maximum loan amount of $2.5 billion, current aggregate lender commitments of $1.3 billion, and a maturity date of April 12, 2018. The borrowing base under the credit facility as of the filing date of this report is $2.2 billion and is subject to regular semi-annual redeterminations. We believe the current commitment amount is sufficient to meet our anticipated liquidity and operating needs. No individual bank participating in our credit facility represents more than 10 percent of the lending commitments under the credit facility. Borrowings under our credit facility are secured by mortgages on at least 75 percent of our proved oil and gas properties. Please refer to Note 5 - Long-term Debt in Part I, Item 1 of this report for additional discussion as well as the presentation of the outstanding balance, total amount of letters of credit, and available borrowing capacity under our credit facility as of July 23, 2014, June 30, 2014, and December 31, 2013.

We are subject to customary covenants under our credit facility, including limitations on dividend payments and requirements to maintain certain financial ratios, which include debt to adjusted EBITDAX, as defined by our credit agreement as the ratio of debt to 12-month trailing adjusted EBITDAX, of less than 4.0, and an adjusted current ratio, as defined by our credit agreement, of no less than 1.0. As of June 30, 2014, our debt to 12-month trailing adjusted EBITDAX ratio and adjusted current ratio were 1.0 and 3.0, respectively. Please refer to Non-GAAP Financial Measures below for our definition of adjusted EBITDAX. As of the filing date of this report, we are in compliance with all covenants under our credit facility.

We had no outstanding balance on our credit facility during the three and six months ended June 30, 2014. Operating cash flow and cash received from the divestiture of properties were sufficient in meeting our capital expenditure needs through the first six months of 2014. Our daily weighted-average credit facility balance was $253.5 million and $323.8 million for the three and six months ended June 30, 2013, respectively. Cash flows provided by our operating activities, proceeds received from divestitures of properties, and the amount of our capital expenditures all impact the amount we have borrowed under our credit facility.

Weighted-Average Interest Rates

Our calculated weighted-average interest rates include accrued interest payments, cash fees on the unused portion of the credit facility's aggregate commitment amount, letter of credit fees, and the non-cash amortization of deferred financing costs. Our calculated weighted-average borrowing rates include accrued interest payments only.

The following table presents our weighted-average interest rates and our weighted-average borrowing rates for the three and six months ended June 30, 2014, and 2013:

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
	2014		2013		2014		2013	
Weighted-average interest rate	6.8	%	6.2	%	6.8	%	6.0	%
Weighted-average borrowing rate	6.1	%	5.6	%	6.1	%	5.5	%

Our weighted-average interest rates and weighted average borrowing rates in 2013 and 2014 have been impacted by the issuance of the 2024 Notes in the second quarter of 2013. This event, as well as the closing of our Anadarko Basin divestiture in December 2013, impacted the average balance on our revolving credit facility and the fees paid on the unused portion of our aggregate commitment.

Uses of Cash

We use cash for the acquisition, exploration, and development of oil and gas properties and for the payment of operating and G&A costs, income taxes, dividends, and debt obligations, including interest. Expenditures for the exploration and development of oil and gas properties are the primary use of our capital resources. In the first six months of 2014, we spent $877.2 million for exploration and development capital activities and proved and unproved oil and gas property acquisitions. These amounts differ from the cost incurred amounts, which are accrual-based and include asset retirement obligation, geological and geophysical expenses ("G&G"), and exploration overhead amounts. The amount and allocation of future capital expenditures will depend upon a number of factors, including the number and size of available acquisition and drilling opportunities, our ability to assimilate acquisitions and execute our drilling program, and our cash flows from operating, investing, and financing activities. In addition, the impact of oil, gas, and NGL prices on investment opportunities, the availability of capital, and the timing and results of our operated and non-operated development and exploratory activities may lead to changes in funding requirements for future development. We periodically review our capital expenditure budget to assess changes in current and projected cash flows, acquisition and divestiture activities, debt requirements, and other factors.

We may from time to time repurchase certain amounts of our outstanding debt securities for cash and/or through exchanges for other securities. Such repurchases or exchanges may be made in open market transactions, privately negotiated transactions, or otherwise. Any such repurchases or exchanges will depend on prevailing market conditions, our liquidity requirements, contractual restrictions, compliance with securities laws, and other factors. The amounts involved in any such transaction may be material.

As of the filing date of this report, we could repurchase up to 3,072,184 shares of our common stock under our stock repurchase program, subject to the approval of our Board of Directors. Shares may be repurchased from time to time in the open market, or in privately negotiated transactions, subject to market conditions and other factors, including certain provisions of our credit facility, the indentures governing our Senior Notes, compliance with securities laws, and the terms and provisions of our stock repurchase program. Our Board of Directors reviews this program as part of the allocation of our capital. We currently do not plan to repurchase any shares in 2014.

The following table presents changes in cash flows between the six months ended June 30, 2014, and 2013. The analysis following the table should be read in conjunction with our condensed consolidated statements of cash flows in Part I, Item 1 of this report.

	For the Six Months Ended June 30,		Amount Change Between Periods	Percent Change Between Periods
	2014	2013		
	(in millions)			
Net cash provided by operating activities	$715.2	$596.4	$118.8	20 %
Net cash used in investing activities	$(832.6)	$(777.8)	$(54.8)	7 %
Net cash provided by (used in) financing activities	$(1.0)	$175.7	$(176.7)	(101)%

Analysis of Cash Flow Changes Between the Six Months Ended June 30, 2014, and 2013

Operating activities. Cash received from oil, gas, and NGL production revenues, including derivative cash settlements, increased $234.6 million, or 24 percent, to $1.2 billion for the first six months of 2014, compared to the same period in 2013. This increase was due to an increase in production volumes and an increase in our realized equivalent price, including the effects of derivative cash settlements. Cash paid for LOE increased $2.4 million to $114.3 million for the first six months of 2014, compared to the same period in 2013, due to increased production and timing of cash payments. Cash paid for interest, net of capitalized interest, during the first six months of 2014 increased $11.3 million compared to the same period in 2013, due to interest paid on our 2024 Notes in the first six months of 2014.

Investing activities. Capital expenditures for the first six months of 2014 increased six percent compared with the same period in 2013 due to increased spending in our Eagle Ford shale and Bakken/Three Forks programs, offset by reduced spending in our Mid-Continent region upon the sale of our Anadarko Basin assets in December 2013. Acquisitions of proved and unproved properties increased $39.4 million as a result of unproved leasehold acquisitions in the Powder River Basin that closed during the second quarter of 2014.

Financing activities. We had no borrowings under our credit facility during the six months ended June 30, 2014, as a result of our positive cash balance at December 31, 2013, upon the closing of our Anadarko Basin divestiture in December 2013, and our strong operating cash flow during the current period. We had net repayments of $312.0 million during the same period in 2013.

Interest Rate Risk and Commodity Price Risk

Our credit agreement allows us to fix the interest rate for all or a portion of the principal balance of our revolving credit facility for a period up to six months; however, our borrowings are generally made with interest rates fixed for one month. Therefore, to the extent we do not repay the principal, our borrowings are rolled over and the interest rate is reset based on the current LIBOR or Alternate Base Rate (“ABR”) as applicable. As a result, changes in interest rates can impact results of operations and cash flows. Changes in interest rates do not impact the amount of interest we pay on our fixed-rate Senior Notes, but can impact their fair market values. As of June 30, 2014, we had $1.6 billion of fixed-rate debt outstanding. Please refer to Note 11 - Fair Value Measurements in Part I, Item 1 of this report for additional discussion on the fair value of our Senior Notes. As of June 30, 2014, we had no floating-rate debt outstanding, thus we had no exposure to market risk directly related to floating interest rates on that date.

The prices we receive for our oil, gas, and NGL production heavily impact our revenue, overall profitability, access to capital, and future rate of production growth. Oil, gas, and NGL prices are subject to wide fluctuations in response to changes in supply and demand. Historically, the markets for oil, gas, and NGLs have been volatile, and these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control.

We enter into commodity derivative contracts in order to reduce the impact of fluctuations in commodity prices. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for information about our oil, gas, and NGL derivative contracts.

There has been no material change to the interest rate risk analysis or oil and gas price sensitivity analysis previously disclosed. Please refer to Interest Rate Risk and Commodity Price Risk in Management's Discussion and Analysis of Financial Condition and Results of Operations in Part II, Item 7 of our 2013 Form 10-K for further discussion.

Off-Balance Sheet Arrangements

We have not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. We evaluate our transactions to determine if any variable interest entities exist. If we determine that we are the primary beneficiary of a variable interest entity, that entity is consolidated into our consolidated financial statements. As of June 30, 2014, all variable interest entities have been consolidated.

Critical Accounting Policies and Estimates

Please refer to the corresponding section in Part II, Item 7 of our 2013 Form 10-K and to the footnote disclosures included in Part I, Item 1 of this report for a discussion of our accounting policies and estimates.

New Accounting Pronouncements

Please refer to Note 2 - Basis of Presentation, Significant Accounting Policies, and Recently Issued Accounting Standards under Part I, Item 1 of this report for new accounting matters.

Non-GAAP Financial Measures

Adjusted EBITDAX represents income before interest expense, other non-operating income or expense, income taxes, depreciation, depletion, amortization, and accretion, exploration expense, property impairments, non-cash stock compensation expense, derivative gains and losses net of cash settlements, change in the Net Profits Plan liability, and gains and losses on divestitures. Adjusted EBITDAX excludes certain items that we believe affect the comparability of operating results and can exclude items that are generally one-time in nature or whose timing and/or amount cannot be reasonably estimated. Adjusted EBITDAX is a non-GAAP measure that is presented because we believe that it provides useful additional information to investors and analysts, as a performance measure, for analysis of our ability to internally generate funds for exploration, development, acquisitions, and to service debt. We are also subject to a financial covenant under our credit facility based on our debt to adjusted EBITDAX ratio. In addition, adjusted EBITDAX is widely used by professional research analysts and others in the valuation, comparison, and investment recommendations of companies in the oil and gas exploration and production industry, and many investors use the published research of industry research analysts in making investment decisions. Adjusted EBITDAX should not be considered in isolation or as a substitute for net income, income from operations, net cash provided by operating activities, or profitability or liquidity measures prepared under GAAP. Because adjusted EBITDAX excludes some, but not all items that affect net income and may vary among companies, the adjusted EBITDAX amounts presented may not be comparable to similar metrics of other companies. The following table provides reconciliations of our net income and net cash provided by operating activities to adjusted EBITDAX for the periods presented:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	2013	2014	2013
	(in thousands)			
Net income (GAAP)	$59,780	$76,522	$125,387	$93,249
Interest expense	24,040	21,581	48,230	40,682
Other non-operating (income) expense, net	1,847	(24)	1,821	(36)
Income tax expense	36,049	46,205	74,912	56,587
Depreciation, depletion, amortization, and asset retirement obligation liability accretion	187,781	225,731	364,996	424,440
Exploration [1]	22,603	18,383	42,541	31,607
Impairment of proved properties	—	34,552	—	55,771
Abandonment and impairment of unproved properties	164	4,339	2,965	4,641
Stock-based compensation expense	7,997	9,955	14,341	18,068
Derivative loss (gain)	126,469	(85,190)	224,131	(54,618)
Derivative cash settlement gain (loss)	(33,680)	2,211	(62,620)	14,003
Change in Net Profits Plan liability	(7,105)	(5,438)	(8,881)	(7,363)
Gain on divestiture activity [2]	(2,526)	(6,280)	(5,484)	(5,706)
Adjusted EBITDAX (Non-GAAP)	423,419	342,547	822,339	671,325
Interest expense	(24,040)	(21,581)	(48,230)	(40,682)
Other non-operating income (expense), net	(1,847)	24	(1,821)	36
Income tax expense	(36,049)	(46,205)	(74,912)	(56,587)
Exploration [1]	(22,603)	(18,383)	(42,541)	(31,607)
Exploratory dry hole expense	6,459	5,727	6,459	5,886
Amortization of deferred financing costs	1,477	1,363	2,954	2,440
Deferred income taxes	35,537	45,959	73,911	56,239
Plugging and abandonment	(1,894)	(2,368)	(3,219)	(3,746)
Changes in current assets and liabilities	36,690	3,047	(14,960)	(12,718)
Other, net	(1,724)	3,933	(4,827)	5,769
Net cash provided by operating activities (GAAP)	$415,425	$314,063	$715,153	$596,355

(1) Stock-based compensation expense is a component of exploration expense and general and administrative expense on the accompanying statements of operations. Therefore, the exploration line items shown in the reconciliation above will vary from the amount shown on the accompanying statements of operations because of the component of stock-based compensation expense recorded to exploration.
(2) Gain on divestiture activity is included within the other operating revenues line item in the accompanying statements of operations.

Cautionary Information about Forward-Looking Statements

This report contains “forward-looking statements” within the meaning of Section 27A of the Securities Act and Section 21E of the Securities Exchange Act of 1934 (the “Exchange Act”). All statements, other than statements of historical facts, included in this report that address activities, events, or developments with respect to our financial condition, results of operations, or economic performance that we expect, believe, or anticipate will or may occur in the future, or that address plans and objectives of management for future operations, are forward-looking statements. The words “anticipate,” “assume,” “believe,” “budget,” “estimate,” “expect,” “forecast,” “intend,” “plan,” “project,” “will,” and similar ex intended to identify forward-looking statements. Forward-looking statements appear in a number of places in this report, and include statements about such matters as:

- the amount and nature of future capital expenditures and the availability of liquidity and capital resources to fund capital expenditures;
- the drilling of wells and other exploration and development activities and plans, as well as possible future acquisitions;
- the possible divestiture or farm-down of, or joint venture relating to, certain properties;
- proved reserve estimates and the estimates of both future net revenues and the present value of future net revenues associated with those proved reserve estimates;
- pending acquisitions of oil and gas assets;
- future oil, gas, and NGL production estimates;
- our outlook on future oil, gas, and NGL prices, well costs, and service costs;
- cash flows, anticipated liquidity, and the future repayment of debt;
- business strategies and other plans and objectives for future operations, including plans for expansion and growth of operations or to defer capital investment, and our outlook on our future financial condition or results of operations; and
- other similar matters such as those discussed in the Management’s Discussion and Analysis of Financial Condition and Results of Operations section of this report.

Our forward-looking statements are based on assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, expected future developments, and other factors that we believe are appropriate under the circumstances. These statements are subject to a number of known and unknown risks and uncertainties, which may cause our actual results and performance to be materially different from any future results or performance expressed or implied by the forward-looking statements. Some of these risks are described under Risk Factors in Item 1A of our 2013 Form 10-K, and include such factors as:

- the volatility of oil, gas, and NGL prices, and the effect it may have on our profitability, financial condition, cash flows, access to capital, and ability to grow production volumes and/or proved reserves;
- weakness in economic conditions and uncertainty in financial markets;
- our ability to replace reserves in order to sustain production;
- our ability to raise the substantial amount of capital that is required to develop and/or replace our reserves;
- our ability to compete against competitors that have greater financial, technical, and human resources;
- our ability to attract and retain key personnel;
- the imprecise estimations of our actual quantities and present value of proved oil, gas, and NGL reserves;
- the uncertainty in evaluating recoverable reserves and estimating expected benefits or liabilities;
- the possibility that exploration and development drilling may not result in commercially producible reserves;

- our limited control over activities on non-operated properties;
- our reliance on the skill and expertise of third-party service providers on our operated properties;
- the possibility that title to properties in which we have an interest may be defective;
- the possibility that our planned drilling in existing or emerging resource plays using some of the latest available horizontal drilling and completion techniques is subject to drilling and completion risks and may not meet our expectations for reserves or production;
- the uncertainties associated with divestitures, joint ventures, farm-downs, farm-outs, and similar transactions with respect to certain assets, including whether such transactions will be consummated or completed in the form or timing and for the value that we anticipate;
- the uncertainties associated with enhanced recovery methods;
- our commodity derivative contracts may result in financial losses or may limit the prices that we receive for oil, gas, and NGL sales;
- the inability of one or more of our service providers, customers, or contractual counterparties to meet their obligations;
- our ability to deliver necessary quantities of oil, gas, or NGLs to contractual counterparties;
- price declines or unsuccessful exploration efforts resulting in write-downs of our asset carrying values;
- the impact that lower oil, gas, or NGL prices could have on the amount we are able to borrow under our credit facility;
- the possibility that our amount of debt may limit our ability to obtain financing for acquisitions, make us more vulnerable to adverse economic conditions, and make it more difficult for us to make payments on our debt;
- the possibility that covenants in our debt agreements may limit our discretion in the operation of our business, prohibit us from engaging in beneficial transactions, or lead to the accelerated payment of our debt;
- operating and environmental risks and hazards that could result in substantial losses;
- the impact of seasonal weather conditions and lease stipulations on our ability to conduct drilling activities;
- our ability to acquire adequate supplies of water and dispose of or recycle water we use at a reasonable cost in accordance with environmental and other applicable rules;
- complex laws and regulations, including environmental regulations, that result in substantial costs and other risks;
- the availability and capacity of gathering, transportation,