SM Energy Co
Form 10-Q
May 03, 2012
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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 March 31, 2012
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 April 27, 2012, the registrant had 64,154,647 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)

	March 31, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$286	$119,194
Accounts receivable	224,335	210,368
Refundable income taxes	2,575	5,581
Prepaid expenses and other	44,141	68,026
Derivative asset	67,457	55,813
Deferred income taxes	4,950	4,222
Total current assets	343,744	463,204
Property and equipment (successful efforts method), at cost:		
Land	1,550	1,548
Proved oil and gas properties	4,657,347	4,378,987
Less - accumulated depletion, depreciation, and amortization	(1,888,104)	(1,766,445)
Unproved oil and gas properties	130,688	120,966
Wells in progress	213,280	273,428
Materials inventory, at lower of cost or market	14,150	16,537
Oil and gas properties held for sale (note 3)	42,189	246
Other property and equipment, net of accumulated depreciation of $25,048 in 2012 and $23,985 in 2011	106,904	71,369
Total property and equipment, net	3,278,004	3,096,636
Other noncurrent assets:		
Derivative asset	30,595	31,062
Restricted cash	114,343	124,703
Other noncurrent assets	78,412	83,375
Total other noncurrent assets	223,350	239,140
Total Assets	$3,845,098	$3,798,980
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$413,211	$456,999
Derivative liability	50,764	42,806
Other current liabilities	7,550	6,000
Total current liabilities	471,525	505,805
Noncurrent liabilities:		
Long-term credit facility	24,000	—
3.50% Senior Convertible Notes, net of unamortized discount of $0 in 2012 and $2,431 in 2011	287,500	285,069
6.625% Senior Notes	350,000	350,000
6.50% Senior Notes	350,000	350,000

Asset retirement obligation	87,647	87,167
Asset retirement obligation associated with oil and gas properties held for sale (note 3)	1,770	1,277
Net Profits Plan liability (note 11)	111,670	107,731
Deferred income taxes	583,660	568,263
Derivative liability	25,397	12,875
Other noncurrent liabilities	61,505	67,853
Total noncurrent liabilities	1,883,149	1,830,235
Commitments and contingencies (note 6)		
Stockholders’ equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued: 64,231,114 shares in 2012 and 64,145,482 shares in 2011; outstanding, net of treasury shares: 64,150,047 shares in 2012 and 64,064,415 shares in 2011	642	641
Additional paid-in capital	222,353	216,966
Treasury stock, at cost: 81,067 shares in 2012 and 2011	(1,544)	(1,544)
Retained earnings	1,274,287	1,251,157
Accumulated other comprehensive loss	(5,314)	(4,280)
Total stockholders' equity	1,490,424	1,462,940
Total Liabilities and Stockholders’ Equity	$3,845,098	$3,798,980

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 March 31, 2012	2011
Operating revenues and other income:		
Oil, gas, and NGL production revenue	$362,595	$276,313
Realized hedge gain (loss) (note 10)	1,652	(1,375)
Gain on divestiture activity	1,462	24,915
Marketed gas system and other operating revenue	11,714	15,476
Total operating revenues and other income	377,423	315,329
Operating expenses:		
Oil, gas, and NGL production expense	87,132	65,812
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	169,570	105,356
Exploration	18,607	12,712
Abandonment and impairment of unproved properties	142	3,079
General and administrative	28,142	25,861
Change in Net Profits Plan liability	3,939	14,195
Unrealized and realized derivative loss (note 10)	2,216	88,429
Marketed gas system and other expense	11,450	19,857
Total operating expenses	321,198	335,301
Income (loss) from operations	56,225	(19,972)
Nonoperating income (expense):		
Interest income	70	128
Interest expense	(14,278)	(9,714)
Income (loss) before income taxes	42,017	(29,558)
Income tax benefit (expense)	(15,681)	11,055
Net income (loss)	$26,336	$(18,503)
Basic weighted-average common shares outstanding	64,104	63,447
Diluted weighted-average common shares outstanding	67,845	63,447
Basic net income (loss) per common share (note 9)	$0.41	$(0.29)
Diluted net income (loss) per common share (note 9)	$0.39	$(0.29)
Dividends per common share	$0.05	$0.05

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 COMPREHENSIVE INCOME (LOSS) (UNAUDITED)
(in thousands)

	For the Three Months Ended March 31,	
	2012	2011
Net income (loss)	$26,336	$(18,503)
Other comprehensive income, net of tax:		
Reclassification of unrealized gain (loss) on derivatives to earnings	(1,034)	927
Total comprehensive income (loss)	$25,302	$(17,576)

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)
(in thousands)

	For the Three Months Ended March 31,	
	2012	2011
Cash flows from operating activities:		
Net income (loss)	$26,336	$(18,503)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Gain on divestiture activity	(1,462)	(24,915)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	169,570	105,356
Exploratory dry hole expense	606	40
Abandonment and impairment of unproved properties	142	3,079
Stock-based compensation expense	4,350	5,551
Change in Net Profits Plan liability	3,939	14,195
Unrealized derivative loss	7,652	82,012
Amortization of debt discount and deferred financing costs	3,665	3,620
Deferred income taxes	15,288	(18,174)
Other	(1,118)	(2,006)
Changes in current assets and liabilities:		
Accounts receivable	(13,967)	16,385
Refundable income taxes	3,006	3,730
Prepaid expenses and other	(3,003)	20,959
Accounts payable and accrued expenses	(26,951)	(28,341)
Excess income tax benefit from the exercise of stock awards	—	(6,303)
Net cash provided by operating activities	188,053	156,685
Cash flows from investing activities:		
Net proceeds from sale of oil and gas properties	1,679	39,023
Capital expenditures	(335,015)	(309,691)
Other	1,550	(2,355)
Net cash used in investing activities	(331,786)	(273,023)
Cash flows from financing activities:		
Proceeds from credit facility	26,000	102,000
Repayment of credit facility	(2,000)	(150,000)
Net proceeds from 6.625% Senior Notes	—	341,435
Proceeds from sale of common stock	1,038	3,460
Excess income tax benefit from the exercise of stock awards	—	6,303
Other	(213)	(643)
Net cash provided by financing activities	24,825	302,555
Net change in cash and cash equivalents	(118,908)	186,217
Cash and cash equivalents at beginning of period	119,194	5,077
Cash and cash equivalents at end of period	$286	$191,294

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 Three Months Ended March 31,	
	2012	2011
	(in thousands)	
Cash paid for interest	$(11,729)	$(1,015)
Net cash refunded for income taxes	$3,397	$3,309

Dividends of approximately $3.2 million had been declared by the Company's Board of Directors, but not paid, for each of the three-month periods ended March 31, 2012, and 2011.

As of March 31, 2012, and 2011, $199.6 million, and $222.8 million, respectively, are included as additions to oil and gas properties and accounts payable and accrued expenses. These oil and gas property additions are reflected in cash used in investing activities in the periods that the payables are settled.

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

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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, natural gas, and natural gas liquids (also referred to as "oil", "gas", and "NGLs" throughout the document) in onshore North America, with a current focus on oil and NGL-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, 2011, (the "2011 Form 10-K"). In the opinion of management, all adjustments, consisting of normal recurring accruals that are 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 condensed consolidated financial statements, the Company evaluated subsequent events after the balance sheet date of March 31, 2012, through the filing date of this report.

Other Significant Accounting Policies

The accounting policies followed by the Company are set forth in Note 1 to the Company's consolidated financial statements in the 2011 Form 10-K, and are supplemented throughout the notes to condensed consolidated financial statements in this report. It is suggested that these condensed consolidated financial statements be read in conjunction with the consolidated financial statements and notes included in the 2011 Form 10-K.

Recently Issued and Recently Adopted Accounting Standards

On January 1, 2012, the Company adopted new fair value measurement authoritative accounting guidance issued by the Financial Accounting Standards Board (the "FASB"), clarifying the application of fair value measurement and disclosure requirements and changed particular principles or requirements for measuring fair value. For each class of assets and liabilities not measured at fair value in the statement of financial position but for which fair value is disclosed, this guidance requires the Company to disclose the nature, characteristics, and risks of the asset or liability and the level of the fair value hierarchy within which the fair value measurement is categorized. Please refer to Note 11 - Fair Value Measurements where the changes of the new pronouncement are reflected.

On January 1, 2012, the Company adopted new authoritative accounting guidance issued by the FASB that states that an entity that reports items of other comprehensive income has the option to present the components of comprehensive income in either one continuous financial statement, or two consecutive financial statements, including reclassification adjustments. Subsequent to the issuance of the authoritative guidance, the FASB issued additional authoritative accounting guidance that effectively deferred the requirement to present the reclassification adjustments on the face of the financial statements, as well as the requirement to present the individual components of other comprehensive income for interim periods. The Company has elected to present a separate statement of comprehensive income, including the individual components, titled Condensed Consolidated Statements of Comprehensive Income (Loss), as part of Item 1 to this report.

There are no new significant accounting standards applicable to SM Energy that have been issued but not yet adopted as of March 31, 2012.

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Note 3 - 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 costs to sell. Subsequent changes to estimated fair value less the cost to sell will impact the measurement of assets held for sale for which fair value
is determined to be less than the carrying value of the assets.

As of March 31, 2012, the accompanying condensed consolidated balance sheets (“accompanying balance sheets”) present $42.2 million of assets held for sale, net of accumulated depletion, depreciation, and amortization. A corresponding asset retirement obligation liability of $1.8 million is separately presented. These assets held for sale and asset retirement obligation liabilities include certain assets located in the Company’s Rocky Mountain region. ThCe Company determined these planned asset sales do not qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

Subsequent to March 31, 2012, the Company began to re-market its Marcellus shale assets located in Pennsylvania and to market certain assets located in its Rocky Mountain region. The aggregate net book value of these assets, net of accumulated depletion, depreciation, and amortization is approximately $55 million. These assets were not classified as held for sale as of March 31, 2012.

Note 4 - Income Taxes

Income tax benefit (expense) for the three months ended March 31, 2012, and 2011, differs from the amounts that would be provided by applying the statutory U.S. federal income tax rate to income before income taxes as a result of the estimated effect of the domestic production activities deduction, percentage depletion, the effect of state income taxes, uncertain tax positions, valuation allowances, and other permanent differences. The quarterly rate can also be impacted by the proportion of income earned in reported periods.

The provision for income taxes consists of the following:

	For the Three Months Ended March 31,			
	2012		2011	
	(in thousands)			
Current portion of income tax benefit (expense):				
Federal	$—		$(6,944	)
State	(393	)	(175	)
Deferred portion of income tax benefit (expense)	(15,288	)	18,174	
Total income tax benefit (expense)	$(15,681	)	$11,055	
Effective tax rate	37.3	%	37.4	%

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 state tax jurisdictions. Cumulative effects of state rate changes are reflected in the period legislation is enacted.

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction and in various states. With certain exceptions, the Company is no longer subject to U.S. federal or state income tax examinations by these tax authorities for years before 2007. In the first quarter of 2011, the Company received a $5.5 million refund from its 2006 tax year as a result of a net operating loss carryback claim from the 2008 tax year. Related to the Company's amended return for the 2007 tax year, the Internal Revenue Service initiated an audit in the first quarter of 2012 for the 2007 and 2010 tax years.

In the third quarter of 2011, the Company completed a multi-year research and development credit study and recorded a cumulative discreet tax benefit. Federal tax law allowing for the calculation of these credits from the Company's increasing research activities has not been extended past December 31, 2011, as of the filing date of this report. For these reasons, comparable first quarter periods of 2012 and 2011 reflect no benefit for the credit.

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Note 5 - Long-Term Debt

Senior Notes

The Company satisfied its obligations to exchange its $350.0 million outstanding 6.50% Senior Notes due 2021 and its $350.0 million outstanding 6.625% Senior Notes due 2019 for notes registered under the Securities Act of 1933, as amended, on March 7, 2012, and January 12, 2012, respectively.

3.50% Senior Convertible Notes Due 2027

Subsequent to March 31, 2012, the Company called for redemption all of its outstanding 3.50% Senior Convertible Notes due 2027 (“3.50% Senior Convertible Notes”). As a result of the redemption notice, the 3.50% Senior Convertible Notes became eligible for conversion until April 30, 2012, and holders of $281.3 million aggregate principal amount of the 3.50% Senior Convertible Notes surrendered their 3.50% Senior Convertible Notes for conversion on or prior to that date. The Company settled and will settle the principal amount of all converted 3.50% Senior Convertible Notes in cash and any excess conversion value with shares of its common stock. The Company redeemed the remaining 3.50% Senior Convertible Notes that were not converted on the redemption date, May 2, 2012, at par plus accrued interest. The Company used and will use funds borrowed under its credit facility to settle the conversion and redemption of its 3.50% Senior Convertible Notes.

Note 6 - Commitments & Contingencies

Commitments

There have been no material changes from the commitments disclosed in the notes to the Company’s consolidated financial statements included in the Company’s 2011 Form 10-K.

Contingencies

The Company is subject to litigation and claims that have arisen 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 cash flows of the Company.

The Company is currently a defendant in litigation where the plaintiffs claim an aggregate overriding royalty interest of 7.46875 percent in production from approximately 22,000 of the Company’s net acres in the Eagle Ford shale play in South Texas. The plaintiffs seek to quiet title to their claimed overriding royalty interest and seek the recovery of unpaid overriding royalty interest proceeds allegedly due. The Texas District Court issued an order granting plaintiffs’ motion for summary judgment, but the Company believes that the summary judgment order is incorrect under the governing agreements and applicable law, and the Company has filed its appeal and will continue to contest the claim. The court entered judgment against all defendants awarding the plaintiffs damages of $5.1 million. If the plaintiffs were to ultimately prevail, the overriding royalty interest would reduce the Company’s net revenue interest in the affected acreage. The Company does not currently believe that an unfavorable ultimate outcome is probable, nor that if the plaintiffs prevail there would be a material effect on the financial position of the Company. Based on the Company’s current view of the facts and circumstances of the case, no accrual has been made for any loss.

Note 7 - Compensation Plans

Cash Bonus Plan

During the first quarters of 2012 and 2011, the Company paid $24.0 million and $21.6 million for cash bonuses earned in the 2011 and 2010 performance years, respectively. Within the general and administrative expense and exploration expense line items in the accompanying condensed consolidated statements of operations (“accompanying statements of operations”), was $4.7 million and $3.8 million of accrued cash bonus plan expense attributable to the three-month periods ended March 31, 2012, and 2011, in each respective specific performance year.

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Restricted Stock Units Under the Equity Incentive Compensation Plan

The Company grants Restricted Stock Units ("RSUs") as part of its long-term equity incentive 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. RSUs are recognized as general and administrative expense and exploration expense over the vesting period of the award.

Total expense recorded for RSUs for the three-month periods ended March 31, 2012, and 2011, was $1.2 million and $1.1 million, respectively. As of March 31, 2012, there was $6.5 million of total unrecognized compensation expense related to unvested RSU awards, which is being amortized through 2014. There have been no material changes to the outstanding and non-vested RSUs during the three months ended March 31, 2012.

Performance Stock Units Under the Equity Incentive Compensation Plan

The Company also grants Performance Share Units as part of its long-term equity incentive compensation program. Performance Stock Units are structurally the same as the previously granted Performance Share Awards (collectively known as "Performance Share Units" or "PSUs"). The number of shares of the Company's common stock issued to settle PSUs ranges from zero to two times the number of PSUs awarded, and is determined based on the Company's performance after completion of a three-year performance period. The performance criteria for the PSUs are based on a combination of the Company's annualized total shareholder return ("TSR") for the performance period and the relative measure of the Company's TSR compared with the annualized TSR of an index comprised of certain peer companies for the performance period. PSUs are recognized as general and administrative expense and exploration expense over the vesting period of the award.

Total expense recorded for PSUs for the three-month periods ended March 31, 2012, and 2011, was $2.9 million and $4.3 million, respectively. As of March 31, 2012, there was $23.3 million of total unrecognized compensation expense related to unvested PSUs that is being amortized through 2014. There have been no material changes to outstanding and non-vested PSUs during the three months ended March 31, 2012.

Stock Option Grants Under the Equity Incentive Compensation Plan

A summary of activity associated with the Company's Stock Option Plan for the three months ended March 31, 2012, is presented in the following table:

	Shares		Weighted-Average Exercise Price	Aggregate Intrinsic Value (in thousands)
Outstanding, at beginning of quarter	508,214		$13.86	$30,109
Exercised	(85,303	)	$12.33	$5,634
Forfeited	—		$—	
Outstanding, at end of quarter	422,911		$14.16	$23,940
Vested and exercisable, at end of quarter	422,911		$14.16	$23,940

As of March 31, 2012, there was no unrecognized compensation expense related to stock option awards.
Net Profits Interest Bonus Plan

Cash payments made or accrued under the Net Profits Interest Bonus Plan ("Net Profits Plan") that have been recorded as either general and administrative expense or exploration expense are detailed in the table below:

	For the Three Months Ended March 31,	
	2012	2011
	(in thousands)	
General and administrative expense	$4,412	$5,330
Exploration expense	525	477
Total	$4,937	$5,807

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Additionally, the Company accrued or made cash payments under the Net Profits Plan of $286,000 and $4.3 million for the three months ended March 31, 2012, and 2011, respectively, as a result of divestiture proceeds. The cash payments are accounted for as a reduction in the gain on divestiture activity 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. The amount recorded as an expense or benefit associated with the change in the estimated liability is not allocated to general and administrative 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 general and administrative expense. The amount that would be allocated to exploration expense is minimal in comparison. Over time, less of the amount distributed relates to prospective exploration efforts as more of the amount distributed is to employees that have terminated employment and do not provide ongoing exploration support to 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”).

Components of Net Periodic Benefit Cost for Both Pension Plans

The following table presents the components of the net periodic benefit cost for both the Qualified Pension Plan and the Nonqualified Pension Plan:

	For the Three Months Ended March 31,	
	2012	2011
	(in thousands)	
Service cost	$950	$848
Interest cost	296	280
Expected return on plan assets that reduces periodic pension costs	(220)	(159)
Amortization of net actuarial loss	101	91
Net periodic benefit cost	$1,127	$1,060

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 ten 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 is required to contribute a total of $5.4 million to its Qualified Pension Plan for the 2012 plan year. The Company has contributed $2.9 million of such amount as of March 31, 2012.

Note 9 - Earnings per Share

Basic net income or loss per common share is calculated by dividing net income or loss available to common shareholders 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.

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Diluted net income or loss per common share is calculated by dividing adjusted net income or loss 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 options, unvested RSUs, contingent PSUs, and shares into which the 3.50% Senior Convertible Notes are convertible.

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 zero to two times 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. 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 Company's 3.50% Senior Convertible Notes include a net-share settlement right giving the Company the option to irrevocably elect, by notice to the trustee under the indenture for the notes, to settle the Company's obligation, in the event that holders of the notes elect to convert all or a portion of their notes, by delivering cash in an amount equal to each $1,000 principal amount of notes surrendered for conversion and, if applicable, at the Company's option, shares of common stock or cash, or any combination of common stock and cash, for the amount of conversion value in excess of the principal amount. Subsequent to March 31, 2012, the Company called for the redemption of all of its outstanding 3.50% Senior Convertible Notes. Please refer to Note 5 - Long-Term Debt for additional discussion. For accounting purposes, the treasury stock method is used to measure the potential dilutive impact of shares associated with this conversion feature. Shares of the Company's common stock traded at a quarterly average closing price exceeding the $54.42 conversion price for the three-month periods ended March 31, 2012, and 2011. As such, the 3.50% Senior Convertible Notes were dilutive for the three-month period ended March 31, 2012, and would have resulted in the notes having a dilutive impact on the Company's first quarter 2011 diluted earnings per share calculation; however, the Company recorded a loss from continuing operations for the period ended March 31, 2011, and as a result, any potentially dilutive shares became anti-dilutive.

The treasury stock method is used to measure the dilutive impact of unvested RSUs, contingent PSUs, in-the-money stock options, and 3.50% Senior Convertible Notes as calculated in the basic and dilutive earnings per share table below. When there is a loss from continuing operations, as was the case for the three months ended March 31, 2011, all potentially dilutive shares are anti-dilutive and are consequently excluded from the calculation of earnings per share.

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

	For the Three Months Ended March 31,		
	2012	2011	
	(in thousands, except per share amounts)		
Net income (loss)	$26,336	$(18,503	)
Basic weighted-average common shares outstanding	64,104	63,447	
Add: dilutive effect of stock options, unvested RSUs, and contingent PSUs	2,210	—	
Add: dilutive effect of 3.50% Senior Convertible Notes	1,531	—	
Diluted weighted-average common shares outstanding	67,845	63,447	
Basic net income (loss) per common share	$0.41	$(0.29	)
Diluted net income (loss) per common share	$0.39	$(0.29	)

Note 10 - Derivative Financial Instruments

The Company has entered into various commodity derivative contracts to mitigate a portion of the exposure to potentially adverse market changes in commodity prices and the associated impact on cash flows. The Company's derivative contracts in place include swap and collar arrangements for oil, gas, and NGLs. As of March 31, 2012, the Company has commodity derivative contracts in place through the fourth quarter of 2014 for a total of 9.7 million Bbls of anticipated oil production, 69.9 million MMBtu of anticipated gas production, and 1.1 million Bbls of anticipated NGL production.

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 asset of $21.9 million and $31.2 million at March 31, 2012, and December 31, 2011, respectively.

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Discontinuance of Cash Flow Hedge Accounting

Prior to January 1, 2011, the Company designated its commodity derivative contracts as cash flow hedges, for which unrealized changes in fair value were recorded to accumulated other comprehensive income (loss) ("AOCIL"), to the extent the hedges were effective. As of January 1, 2011, the Company elected to de-designate all of its commodity derivative contracts that had been previously designated as cash flow hedges at December 31, 2010. As a result, subsequent to December 31, 2010, the Company recognized all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in AOCIL. The Company had no derivatives designated as cash flow hedges for the three-month periods ended March 31, 2012, and 2011, and as such, no ineffectiveness was recognized in earnings for the respective periods.

As a result of discontinuing hedge accounting on January 1, 2011, such fair values at December 31, 2010, were frozen in AOCIL as of the de-designation date and are reclassified into earnings as the original derivative transactions settle. As of March 31, 2012, AOCIL included $115,000 of net unrealized gains, net of income tax, on commodity derivative contracts that had been previously designated as cash flow hedges. The Company expects to reclassify into earnings from AOCIL after-tax net gains of $1.3 million related to de-designated commodity derivative contracts during the next twelve months. Please refer to Note 11 - Fair Value Measurements for more information regarding the Company's derivative instruments, including our valuation techniques.

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

	As of March 31, 2012			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity Contracts	Current Assets	$67,457	Current Liabilities	$50,764
Commodity Contracts	Noncurrent Assets	30,595	Noncurrent Liabilities	25,397
Derivatives not designated as hedging instruments		$98,052		$76,161

	As of December 31, 2011			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity Contracts	Current Assets	$55,813	Current Liabilities	$42,806
Commodity Contracts	Noncurrent Assets	31,062	Noncurrent Liabilities	12,875
Derivatives not designated as hedging instruments		$86,875		$55,681

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The following table summarizes the components of unrealized and realized derivative loss presented in the accompanying statements of operations:

	For the Three Months Ended March 31,			
	2012		2011	
	(in thousands)			
Cash settlement (gain) loss:				
Oil contracts	$8,299		$6,730	
Gas contracts	(15,212	)	(1,727	)
NGL contracts	1,477		1,414	
Total cash settlement (gain) loss	$(5,436	)	$6,417	
Unrealized (gain) loss on change in fair value:				
Oil contracts	$29,491		$67,367	
Gas contracts	(17,634	)	4,260	
NGL contracts	(4,205	)	10,385	
Total net unrealized loss on change in fair value	$7,652		$82,012	
Total unrealized and realized derivative loss	$2,216		$88,429	

The following table summarizes the effect of derivative instruments on AOCIL and the accompanying statements of operations (net of income tax):

	Derivatives	Location in Consolidated Statements of Operations	For the Three Months Ended March 31,		
			2012		2011
			(in thousands)		
Amount reclassified from AOCIL to realized hedge gain (loss)	Commodity Contracts	Realized hedge gain (loss)	$(1,034	)	$927

The Company realized a net hedge gain of $1.7 million and a net hedge loss of $1.4 million from its commodity derivative contracts for the three months ended March 31, 2012, and 2011, respectively, shown net of income tax in the table above. Realized hedge gains and losses are comprised of realized cash settlements on commodity derivative contracts that were previously designated as cash flow hedges and are reported in the total operating revenues and other income section of the accompanying statements of operations.

Credit Related Contingent Features

As of March 31, 2012, and through the filing date of this report, all of the Company’s derivative counterparties were members of the Company’s credit facility syndicate. The Company’s obligations under its credit facility and derivative contracts are secured by liens on substantially all of the Company’s proved oil and gas properties.

Convertible Note Derivative Instruments

The contingent interest provision of the 3.50% Senior Convertible Notes is an embedded derivative instrument. As of March 31, 2012, and December 31, 2011, the fair value of this derivative was determined to be immaterial.

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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 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 financial assets and liabilities that are measured at fair value on a recurring basis and where they are classified within the hierarchy as of March 31, 2012:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives	$—	$98,052	$—
Liabilities:			
Derivatives	$—	$76,161	$—
Net Profits Plan	$—	$—	$111,670

The following is a listing of the Company's assets and liabilities that are measured at fair value and where they were classified within the hierarchy as of December 31, 2011:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives (1)	$—	$86,875	$—
Proved oil and gas properties (2)	$—	$—	$139,992
Unproved oil and gas properties (2)	$—	$—	$15,809
Liabilities:			
Derivatives (1)	$—	$55,681	$—
Net Profits Plan (1)	$—	$—	$107,731

(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 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 hierarchy. There were no non-financial assets or liabilities measured at fair value on a nonrecurring basis at March 31, 2012.

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

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counterparties' mark-to-market statements. The considered 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 ask 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 bank syndicate.

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 accounting authoritative 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. For those pools currently in payout, a discount rate of 12 percent is used to calculate this liability. A discount rate of 15 percent is used to calculate the liability for pools that have not reached payout. These rates are intended to represent the 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 the overall market conditions, which are continually evaluated to consider 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 crude oil, gas, and NGL commodity markets.

If the commodity prices used in the calculation changed by five percent, the liability recorded at March 31, 2012, would differ by approximately $9 million. A one percent increase or decrease in the discount rate would result in a change of approximately $5 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 the 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.

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

	For the Three Months Ended March 31,	
	2012	2011
	(in thousands)	
Beginning balance	$107,731	$135,850
Net increase in liability [(1)]	9,162	24,285
Net settlements [(1)(2)(3)]	(5,223)	(12,732)
Transfers in (out) of Level 3	—	—
Ending balance	$111,670	$147,403

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(1) Net changes in the 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 relating to divestiture proceeds of $286,000 and $4.3 million for the three months ended March 31, 2012, and March 31, 2011, respectively.

(3) During the first quarter of 2011, the Company elected to cash out several Net Profits Plan pools associated with the acquisition of Nance Petroleum Corporation in 1999, through a $2.6 million direct payment. As a result, the Company reduced its Net Profits Plan liability by that amount. There is no impact on the accompanying statements of operations for the three-month period ended March 31, 2011, related to these settlements.

Long-term Debt

The 3.50% Senior Convertible Notes are valued using Level 1 inputs based on quoted secondary market trading prices. The estimated fair value of these notes was approximately $374 million and $394 million as of March 31, 2012, and December 31, 2011, respectively. The fair value of the embedded contingent interest derivative was immaterial as of March 31, 2012, and December 31, 2011.

The 6.625% Senior Notes and 6.50% Senior Notes are valued using Level 1 inputs based on quoted secondary market trading prices. The estimated fair value of the 6.625% Senior Notes and the 6.50% Senior Notes as of March 31, 2012, was approximately $371 million and $373 million, respectively, and as of December 31, 2011, was approximately $359 million and $360 million, respectively.

Proved 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 for the year ended December 31, 2011. Management 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 price forecast is based on New York Mercantile Exchange ("NYMEX") strip pricing, adjusted for basis differentials, for the first five years. At the end of the first five years, a flat terminal price is used. Future operating costs are also adjusted as deemed appropriate for these estimates.

There were no proved oil and gas properties measured at fair value at March 31, 2012. As a result of asset write-downs, the Company's proved oil and gas properties measured at fair value within the accompanying balance sheets were $140.0 million as of December 31, 2011.

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Unproved Oil and Gas Properties

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. 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 to measure the fair value of unproved properties.
There were no unproved oil and gas properties measured at fair value at March 31, 2012. As a result of the asset write-downs, the Company's unproved oil and gas properties measured at fair value within the accompanying balance sheets were $15.8 million as of December 31, 2011.

Materials Inventory

Materials inventory is valued at the lower of cost or market. The Company uses Level 2 inputs to measure the fair value of materials inventory, which is primarily comprised of tubular goods. The Company uses third party market quotes and compares the quotes to the book value of the materials inventory. If the book value exceeds the quoted market price, the Company reduces the book value to the market price. The considered factors result in an estimated exit price that management believes provides a reasonable and consistent methodology for valuing materials inventory. There were no materials inventories measured at fair value within the accompanying balance sheets at March 31, 2012, or December 31, 2011.

Asset Retirement Obligations

The income valuation technique is utilized by the Company 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 measured at fair value within the accompanying balance sheets at March 31, 2012, or December 31, 2011.

Note 12 - Acquisition and Development Agreement

In June 2011, the Company entered into an Acquisition and Development Agreement with Mitsui E&P Texas LP ("Mitsui"), an indirect subsidiary of Mitsui & Co., Ltd. (the "Acquisition and Development Agreement"). Pursuant to the Acquisition and Development Agreement, the Company agreed to transfer to Mitsui a 12.5 percent working interest in certain non-operated oil and gas assets representing approximately 39,000 net acres in Dimmit, LaSalle, Maverick, and Webb Counties, Texas. As consideration for the oil and gas interests transferred, Mitsui agreed to pay, or carry, 90 percent of certain drilling and completion costs attributable to the Company's remaining interest in these assets following the closing of the transaction, until Mitsui has expended an aggregate $680.0 million on behalf of the Company. Based on the Company's forecast of the operator's drilling plans, it will take three to four years to fully utilize the carry. Mitsui also reimbursed the Company for capital expenditures and other costs, net of revenues, that the Company paid that were attributable to the transferred interest during the period between the effective date and the closing date. The Company will apply these reimbursed costs to the remaining ten percent of the Company's drilling and completion costs for the affected acreage.

As of March 31, 2012, the Company held $114.3 million of contractually restricted cash payments from Mitsui, which will be used solely for development operations and accordingly are classified as non-current assets in the accompanying balance sheets. The Company has recorded a corresponding liability equal to the restricted cash balance. The portion of the liability related to development operations expected to occur within the next year is recorded in accounts payable and accrued expenses within the accompanying balance sheets. The portion of the liability related to development operations expected to occur more than one year in the future is recorded in other noncurrent liabilities within the accompanying balance sheets as of March 31, 2012. There was no net impact on the accompanying condensed consolidated statement of cash flows as restricted cash was offset against the corresponding liability in investing activities. Of the $680.0 million carry amount, the Company has spent $61.9 million as of March 31, 2012.

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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, as well as meaningful positions in the Granite Wash, Haynesville shale, Woodford shale resource plays, and the Permian Basin. We have built a portfolio of onshore properties in the contiguous United States primarily through early entrance 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 reserve growth.
Our business strategy is focused on the early capture of resource plays in order to create and then enhance value for our shareholders, 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 captured potential value through these efforts, our goal is to develop such potential through top-tier operational and project execution, and as appropriate, mitigate our risks by selectively divesting portions of certain assets. We continually examine our portfolio for opportunities to improve the quality of our asset base in order to maximize our returns and preserve our financial strength.

In the first quarter of 2012, we had the following financial and operational results:

- Our average daily production for the three months ended March 31, 2012, was 27.6 MBbls of oil, 314.9 MMcf of gas, and 12.8 MBbls of NGLs, for an average equivalent production rate of 557.0 MMCFE per day, compared with 401.4 MMCFE per day for the same period in 2011. Please see additional discussion below under the caption Production Results.

- We recorded net income for the three months ended March 31, 2012, of $26.3 million or $0.39 per diluted share compared to a net loss for the three months ended March 31, 2011, of $(18.5) million or $(0.29) per diluted share.

- Costs incurred for oil and gas producing activities for the three months ended March 31, 2012, were $368.0 million, compared with $290.7 million for the same period in 2011. Please see additional discussion below under the caption Costs Incurred in Oil and Gas Producing Activities.

- Our EBITDAX, a non-GAAP financial measure, for the three months ended March 31, 2012, was $259.0 million compared with $178.0 million for the same period in 2011. Please refer to the caption Non-GAAP Financial Measures below for additional discussion, including a reconciliation from GAAP net income (loss) to EBITDAX.

Oil, Gas, and NGL Prices

Our financial condition and the results of our operations are significantly affected by the prices we receive for 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 Oil Price Information System Mont Belvieu (“OPIS”) daily settlement prices, adjusted for processing, transportation, and location differentials. Our oil and condensate are sold using contracts paying us either the average of the NYMEX West Texas Intermediate (“WTI”) daily settlement price or the average of alternative posted prices for the periods in which the product is produced, adjusted for quality, transportation, and location differentials.

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The following table is a summary of commodity price data for the first quarter of 2012, as well as the fourth and first quarters of 2011:

	For the Three Months Ended		
	March 31, 2012	December 31, 2011	March 31, 2011
Crude Oil (per Bbl):			
Average NYMEX price	$102.99	$94.03	$94.46
Realized price	$90.67	$87.52	$85.79
Natural Gas:			
Average NYMEX price (per MMBtu)	$2.44	$3.33	$4.18
Realized price (per Mcf)	$2.90	$3.86	$4.35
Natural Gas Liquids (per Bbl):			
Average OPIS price	$54.15	$60.59	$56.28
Realized price	$44.67	$54.36	$46.65

Note: Average OPIS prices per barrel of NGL, historical or strip, are based on a product mix of 37% Ethane, 6% Isobutane, 11% Normal Butane, 14% Natural Gasoline and 32% Propane for all periods presented.

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 likely continue to be impacted by real or perceived geopolitical risks in oil producing regions of the world, particularly in the Middle East. Additionally, the relative strength of the U.S. Dollar compared to other currencies could affect the price of oil. The supply of NGLs in the U.S. is expected to grow in the near term as a result of a number of industry participants targeting projects that produce these products, which could negatively impact future pricing. The pricing of several of the specific NGL products have strong correlations to the price of oil and accordingly are likely to directionally follow that market. Gas prices are under downward pressure due to current market oversupply because of high levels of drilling activity, high levels of gas in storage, an unusually mild winter in the United States, and tepid economic growth. The 12-month strip prices for NYMEX WTI oil, NYMEX Henry Hub gas, and OPIS NGLs (same product mix as discussed above) as of March 31, 2012, were $104.63 per Bbl of oil, $2.80 per MMBtu of gas, and $52.79 per Bbl of NGLs, respectively. Comparable prices as of April 27, 2012, were $105.72 per Bbl of oil, $2.84 per MMBtu of gas, and $60.68 per Bbl of NGLs, respectively. While changes in 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. Our realized prices shown in the table above do not include the impact of cash settlements from derivative contracts, which is consistent with all prior periods reported.

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 level 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 partially reduced our exposure to volatility in commodity prices. Our use of collars for a portion of the 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 of Part I, Item 1 of this report for additional information regarding our oil, gas, and NGL derivatives, and the caption, Summary of Oil, Gas, and NGL Derivative Contracts in Place, below.

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The following table is a reconciliation from our realized prices to our adjusted price for the commodities indicated, including the effects of derivative cash settlements for the first quarter of 2012, as well as the fourth and first quarters of 2011:

	For the Three Months Ended		
	March 31, 2012	December 31, 2011	March 31, 2011
Crude Oil (per Bbl):			
Realized price	$90.67	$87.52	$85.79
Less the effects of derivative cash settlements	(4.32)	(6.89)	(10.72)
Adjusted price, including the effects of derivative cash settlements	$86.35	$80.63	$75.07
Natural Gas (per Mcf):			
Realized price	$2.90	$3.86	$4.35
Add the effects of derivative cash settlements	0.70	0.50	0.69
Adjusted price, including the effects of derivative cash settlements	$3.60	$4.36	$5.04
Natural Gas Liquids (per Bbl):			
Realized price	$44.67	$54.36	$46.65
Less the effects of derivative cash settlements	(1.69)	(3.99)	(5.76)
Adjusted price, including the effects of derivative cash settlements	$42.98	$50.37	$40.89

The Dodd-Frank Wall Street Reform and Consumer Protection Act (“Dodd-Frank Act”) included provisions requiring over-the-counter derivative transactions to be executed through an exchange or centrally cleared. The Dodd-Frank Act requires the Commodities Futures Trading Commission (“CFTC”), the Securities and Exchange Commission (“SEC”), and other regulators to establish rules and regulations to implement the new legislation by July 16, 2012. The CFTC has proposed new rules governing margin requirements for uncleared swaps entered into by non-bank swap entities, and U.S. banking regulators have proposed new rules regarding margin requirements for uncleared swaps entered into by bank swap entities. The ultimate effect on our business of the proposed new rules and any additional regulations is currently uncertain. Of particular concern to us is whether the provisions of the final rules and regulations will allow us to qualify as a non-financial, commercial end user exempt 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.

First Quarter 2012 Highlights

Operational Activities. We had 15 operated drilling rigs running in our development programs at the end of the first quarter of 2012. The primary focus of our operated drilling activity this year has been on oil and NGL-rich gas projects. We also participated in non-operated activity primarily in oil and NGL-rich plays.

In our Eagle Ford shale program in South Texas, we had six operated drilling rigs at the end of the first quarter of 2012. We focused our drilling in areas with higher BTU gas content and condensate yields. We believe we have enough pipeline takeaway capacity, drilling, and completion services for our current development plans, but we will continue to explore additional arrangements to facilitate the future growth of our operated program. In our non-operated Eagle Ford program, the operator had ten drilling rigs running during the first quarter of 2012. Under our transaction with Mitsui, we transferred a 12.5 percent working interest in certain oil and gas assets and acreage and in return Mitsui agreed to carry 90 percent of certain drilling and completion costs on our behalf. We will also apply the reimbursed costs from Mitsui for the period between the effective date and the closing date to the remaining ten percent of our drilling and completion costs in this program. We expect this carry arrangement to fund most of our portion of this non-operated drilling program for the next three to four years.

We operated three drilling rigs in the North Dakota portion of the Williston Basin throughout the first quarter of 2012, all of which were focused on Bakken/Three Forks drilling in our Gooseneck, Raven, and Bear Den prospects. We also operated one rig testing various formations in the DJ and Powder River basins of Wyoming.

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Effective January 1, 2012, we combined our ArkLaTex region into our Mid-Continent region, based in Tulsa, Oklahoma, for operational and reporting purposes. During the three months ended March 31, 2012, we operated three drilling rigs in our Granite Wash program in western Oklahoma and the Texas Panhandle to test and delineate our acreage in the play. The majority of our acreage position in this play is held by production and we believe this program's potential could be significant. We operated one rig in our Haynesville shale program during the first quarter of 2012. Approximately 80 percent of our operated acreage position in the Haynesville shale is held by production and we have now completed our Haynesville drilling for 2012.

Our Permian region operated one rig throughout the first quarter of 2012 that focused on testing the Mississippian limestone formation.

Production Results. The table below provides a regional breakdown of our first quarter 2012 production:

	South Texas & Gulf Coast	Mid-Continent	Permian	Rocky Mountain	Total [1]
First Quarter 2012 Production:					
Oil (MMBbl)	0.8	0.1	0.3	1.3	2.5
Gas (Bcf)	12.8	13.9	0.8	1.2	28.7
NGLs (MMBbl)	1.1	0.1	—	—	1.2
Equivalent (BCFE)	23.9	15.0	2.6	9.2	50.7
Avg. Daily Equivalents (MMCFE/d)	262.2	164.6	28.8	101.5	557.0
Relative percentage	47 %	30 %	5 %	18 %	100 %

[1] Totals may not add due to rounding.

For the first quarter of 2012, our production was led by our South Texas & Gulf Coast region due to our focus on the development of our Eagle Ford shale program. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended March 31, 2012, and 2011 for additional discussion on production.

Costs Incurred in Oil and Gas Producing Activities. Costs incurred in oil and gas property acquisition, exploration and development activities, whether capitalized or expensed, are summarized as follows:

	For the Three Months Ended March 31, 2012 (in millions)
Development costs	$286.6
Facility costs	11.2
Exploration costs	46.0
Acquisitions	
Leasing activity	24.2
Total, including asset retirement obligations	$368.0

The majority of costs incurred for oil and gas producing activities during the first quarter of 2012 were spent on the development of our Eagle Ford and Bakken/Three Forks shale programs. Please refer to Overview of Liquidity and Capital Resources below for additional discussion on how we fund our capital program.

Subsequent Events. Subsequent to March 31, 2012, we called for redemption all of our outstanding 3.50% Senior Convertible Notes. Additionally, we began to re-market our Marcellus shale assets located in Pennsylvania and to market certain assets located in our Rocky Mountain region. Please refer to Note 3 - Assets Held for Sale and Note 5 - Long-Term Debt in Part I, Item 1 of this report, as well as Legal Proceedings in Part II, Item 1 of this report for additional information.

Outlook for the Remainder of 2012

Our capital program for 2012 is expected to be within the range of $1.4 billion to $1.5 billion, of which approximately $1.2 billion to $1.3 billion will be focused on drilling and completion activities. Approximately 90 percent of our drilling budget is expected to be spent on our operated acreage, and over 95 percent of our allocated drilling and completion capital is expected to be directed to oilier and NGL-rich projects.

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In 2012, we plan to invest between $650 million and $700 million of drilling and completion capital in our operated Eagle Ford shale play. We currently are operating six drilling rigs in this program. We anticipate reducing the rig count to five during the year once we have completed our transition to pad drilling. Our operated rig fleet is expected to consist of three rigs designed for pad drilling and the remaining two rigs are expected to be drilling wells throughout our acreage position to satisfy lease obligations. We expect to focus our drilling on the oily and NGL-rich portion of our position. During 2012, we plan to continue testing down-spacing pilots to determine the ultimate development spacing for our acreage position. Along with down-spacing tests, we intend to continue to refine our development program and well designs to optimize well performance and capital efficiency.

In our non-operated Eagle Ford shale program, the operator is currently operating ten drilling rigs. Based on the operator’s stated plans, our expectation is that the number of rigs will remain constant throughout the year. Mitsui is obligated to carry the majority of the drilling and completion costs of our non-operated drilling activity through 2012 and, as such, we expect to deploy minimal capital related to drilling in this program. Costs that are not associated with drilling or completion activities, such as infrastructure construction, are not carried by Mitsui, and accordingly we will be responsible for our proportionate share of these costs.

We plan to invest between $160 million and $185 million of our capital budget in our operated Bakken/Three Forks program in the North Dakota portion of the Williston Basin in 2012. We currently operate three drilling rigs in this program and plan to add a fourth rig in the second quarter of 2012. Our plan with these rigs is to hold our Raven and Gooseneck prospects through production and to begin infill drilling in our Bear Den prospect, which is already held by production.

In our Granite Wash program, we are currently running three drilling rigs focused on the liquids-rich Marmaton and Missourian washes. We have allocated approximately $60 million to $70 million to this program, which we expect to invest to further delineate the play in our acreage position. We plan to operate three rigs in this program for the remainder of the year.

In our southern Rockies program, we have allocated capital to test various geologic formations, including the Niobrara and Frontier intervals, in the DJ and Powder River Basins of Wyoming. We also have activity planned in our Permian region, where we are primarily testing the Mississippian limestone. We have allocated approximately $130 million to $150 million in aggregate for these two programs. In addition to these exploratory programs, we have allocated approximately $100 million to our exploration efforts to identify new resource plays; the allocated capital is expected to be used to acquire acreage and test exploration concepts.

Please refer to Overview of Liquidity and Capital Resources for additional discussion regarding how we intend to fund our 2012 capital program.

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Financial Results of Operations and Additional Comparative Data

The table below provides information regarding selected production and financial information for the quarter ended March 31, 2012, and the immediately preceding three quarters. Additional details of per MCFE costs are presented later in this section.

	For the Three Months Ended			
	March 31, 2012	December 31, 2011	September 30, 2011	June 30, 2011
	(in millions, except for production data)			
Production (BCFE) [1]	50.7	51.3	42.5	39.8
Oil, gas, and NGL production revenue	$362.6	$397.0	$325.2	$333.9
Realized hedge gain (loss)	$1.7	$(6.2)	$(6.8)	$(6.3)
Gain (loss) on divestiture activity	$1.5	$(25.0)	$190.7	$30.0
Lease operating expense	$39.4	$43.5	$40.0	$33.2
Transportation costs	$28.6	$30.7	$23.9	$16.9
Production taxes	$19.1	$19.0	$13.8	$3.3
DD&A	$169.6	$167.3	$123.1	$115.4
Exploration	$18.6	$20.0	$11.3	$9.6
Impairment of proved properties	$—	$170.5	$48.5	$—
General and administrative	$28.1	$35.6	$29.8	$27.3
Change in Net Profits Plan liability	$3.9	$(0.8)	$(24.9)	$(14.0)
Unrealized and realized derivative (gain) loss	$2.2	$46.8	$(128.4)	$(43.9)
Net income (loss)	$26.3	$(120.7)	$230.1	$124.5

[1] Adjusting for divestitures, our production for the quarter ended March 31, 2012, increased four percent from the previous quarter.

Selected Performance Metrics:

	For the Three Months Ended			
	March 31, 2012	December 31, 2011	September 30, 2011	June 30, 2011
Average net daily production equivalent (MMCFE per day)	557.0	557.9	462.1	436.9
Lease operating expense (per MCFE)	$0.78	$0.85	$0.94	$0.84
Transportation costs (per MCFE)	$0.56	$0.60	$0.56	$0.42
Production taxes as a percent of oil, gas, and NGL production revenue	5.3%	4.8%	4.3%	1.0%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion (per MCFE)	$3.35	$3.26	$2.89	$2.90
General and administrative (per MCFE)	$0.56	$0.69	$0.70	$0.69

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

	For the Three Months Ended March 31, 2012	2011	Amount Change Between Periods	Percent Change Between Periods
Net production volumes				
Oil (MMBbl)	2.5	1.8	0.7	41 %
Gas (Bcf)	28.7	21.7	6.9	32 %
NGLs (MMBbl)	1.2	0.6	0.5	90 %
Equivalent (BCFE)	50.7	36.1	14.6	40 %
Average net daily production				
Oil (MBbl per day)	27.6	19.8	7.7	39 %
Gas (MMcf per day)	314.9	241.5	73.4	30 %
NGLs (MBbl per day)	12.8	6.8	6.0	87 %
Equivalent (MMCFE per day)	557.0	401.4	155.6	39 %
Oil, gas, & NGL production revenue (in millions)				
Oil production revenue	$227.4	$153.1	$74.3	49 %
Gas production revenue	83.2	94.5	(11.3)	(12)%
NGL production revenue	52.0	28.7	23.3	81 %
Total	$362.6	$276.3	$86.3	31 %
Oil, gas, & NGL production expense (in millions)				
Lease operating expense	$39.4	$33.0	$6.4	19 %
Transportation costs	28.6	15.0	13.6	91 %
Production taxes	19.1	17.8	1.3	7 %
Total	$87.1	$65.8	$21.3	32 %
Realized price				
Oil (per Bbl)	$90.67	$85.79	$4.88	6 %
Gas (per Mcf)	$2.90	$4.35	$(1.45)	(33)%
NGLs (per Bbl)	$44.67	$46.65	$(1.98)	(4)%
Per MCFE	$7.15	$7.65	$(0.50)	(7)%
Per MCFE Data				
Production costs:				
Lease operating expenses	$0.78	$0.92	$(0.14)	(15)%
Transportation costs	$0.56	$0.41	$0.15	37 %
Production taxes	$0.38	$0.49	$(0.11)	(22)%
General and administrative	$0.56	$0.72	$(0.16)	(22)%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$3.35	$2.92	$0.43	15 %
Derivative cash settlement [1]	$0.14	$(0.22)	$0.36	(164)%
Earnings per share information				
Basic net income (loss) per common share	$0.41	$(0.29)	$0.70	(241)%
Diluted net income (loss) per common share	$0.39	$(0.29)	$0.68	(234)%
Basic weighted-average common shares outstanding	64,104	63,447	657	1 %
Diluted weighted-average common shares outstanding	67,845	63,447	4,398	7 %

[1] Derivative cash settlements are included within the realized hedge gain (loss) and unrealized and realized derivative loss line items in the accompanying statements of operations.

We present per MCFE information because we use this information to evaluate our performance relative to our peers and to identify and measure trends that we believe require analysis. Average daily reported production for the first three months of 2012 increased 39 percent compared with the same period in 2011, driven primarily by the development of our Eagle Ford shale program, as well as a substantial increase in production in our Bakken/Three Forks program in our Rocky Mountain region.

Changes in production volumes, revenues, and costs reflect the cyclical and highly volatile nature of our industry. Our realized price on a per MCFE basis decreased seven percent for the three months ended March 31, 2012, compared to the same period in 2011. The decrease in our realized price is due primarily to a decline in natural gas prices.

Our LOE on a per MCFE basis for the three months ended March 31, 2012, decreased 15 percent compared to the same period in 2011 due largely to our production rate increase exceeding the increase in LOE incurred, the divestiture in the second quarter of 2011 of non-strategic properties with meaningfully higher per unit operating costs within our Mid-Continent region, and a decrease in workover LOE in our South Texas & Gulf Coast region. We believe the current high level of industry activity, particularly in oilier and rich-gas plays, has the potential to increase LOE in 2012.

Production taxes on a per MCFE basis for the three months ended March 31, 2012, decreased 22 percent compared to the same period in 2011. We generally expect production taxes to trend with oil, gas, and NGL revenues. In the second quarter of 2011, we were notified that we qualified for severance tax incentive rebate programs for certain wells in Texas, which reduced our overall production tax expense. We expect our future operated wells drilled in these areas to qualify for reduced tax rates.

Transportation costs on a per MCFE basis for the three months ended March 31, 2012, increased 37 percent compared to the same period in 2011. This is a result of increased production in our Eagle Ford shale program, where transportation arrangements have resulted in higher per unit transportation costs due to the costs of developing infrastructure in this emerging play. We anticipate transportation costs will continue to increase on a per MCFE basis as the Eagle Ford shale becomes a larger portion of our production.

Our general and administrative expense on a per MCFE basis for the three months ended March 31, 2012, decreased 22 percent compared to the same period in 2011. Production increased at a faster rate than our general and administrative expense. A portion of our general and administrative 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 are tied to net revenues and therefore are subject to variability.

Our DD&A expense on a per MCFE basis, for the three months ended March 31, 2012, increased 15 percent compared to the same period in 2011. Our DD&A rate increased as a result of the transfer of a portion of our non-operated working interest to Mitsui, which reduced our reserve base but had no impact on the carrying value of our assets. Please refer to Note 12 - Acquisition and Development Agreement in Part I, Item 1 of this report for additional discussion on the Mitsui transaction. Our DD&A rate can fluctuate as a result of impairments, divestitures, and changes in the mix of our production and the underlying proved reserve volumes. Additionally, the accounting treatment for assets that are classified as assets held for sale can also impact our DD&A rate since properties held for sale are no longer depleted.

Please refer to Comparison of Financial Results and Trends Between the Three Months Ended March 31, 2012, and 2011 and for additional discussion on oil, gas, and NGL production expense, DD&A, and general and administrative expense.
Please refer to Note 9 - Earnings per Share in Part I, Item 1 of this report for additional discussion on the type of shares included in our basic and diluted net income (loss) per common share calculations. Subsequent to March 31, 2012, we called for redemption all of our outstanding 3.50% Senior Convertible Notes, and as a result, the 3.50% Senior Convertible Notes were eligible for conversion prior to the redemption date. The shares issued and to be issued upon conversion will be reflected in our basic net income (loss) per common share calculation in the second quarter of 2012. Please refer to Note 5 - Long-Term Debt in Part I, Item 1 of this report for additional discussion on our 3.50% Senior Convertible Notes.

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Comparison of Financial Results and Trends Between the Three Months Ended March 31, 2012, and 2011

Oil, gas, and NGL production revenue. Average daily production increased 39 percent to 557.0 MMCFE for the quarter ended March 31, 2012, compared with 401.4 MMCFE for the quarter ended March 31, 2011. The following table presents the regional changes in our oil, gas, and NGL production, revenues, and costs between the two quarters:

	Average Net Daily Production Added (Lost) (MMCFE/d)	Oil, Gas, & NGL Revenue Added (Lost) (in millions)	Production Costs Increase (Decrease) (in millions)
South Texas & Gulf Coast	114.5	$58.3	$12.7
Mid-Continent	14.8	(9.5)	0.8
Permian	(5.2)	(4.7)	(0.7)
Rocky Mountain	31.5	42.2	8.5
Total	155.6	$86.3	$21.3

The largest regional production increase occurred in the South Texas & Gulf Coast region as a result of production from drilling activity in our Eagle Ford shale program. Activity in our Eagle Ford shale program continues to increase, and we expect production from this region to increase for the next several years. We also saw an increase in production in our Rocky Mountain region as a result of strong production performance from wells drilled in our Bakken/Three Forks shale program in late 2011 and early 2012.

The following table summarizes the realized prices we received for the three months ended March 31, 2012, and 2011, before the effects of derivative cash settlements:

	For the Three Months Ended March 31,	
	2012	2011
Realized oil price ($/Bbl)	$90.67	$85.79
Realized gas price ($/Mcf)	$2.90	$4.35
Realized NGL price ($/Bbl)	$44.67	$46.65
Realized equivalent price ($/MCFE)	$7.15	$7.65

Revenue increased substantially between the two periods due to a 40 percent increase in net production volumes on an equivalent basis, which was partially offset by a seven percent decrease in the realized price per MCFE. We expect our realized prices to trend with commodity prices. At current levels of anticipated activity, we expect production volumes to increase annually for the next several years.

Realized hedge gain (loss). We recorded a net realized hedge gain of $1.7 million for the three-month period ended March 31, 2012, compared with a $1.4 million net loss for the same period in 2011. These amounts are comprised of realized cash settlements on commodity derivative contracts that were previously recorded in AOCIL. Our realized oil, gas, and NGL hedge gains and losses are a function of commodity prices at the time of settlement and the price at the time the derivative transaction was entered into.

Gain on divestiture activity. There were no significant divestitures for the quarter ended March 31, 2012. We recorded a $24.9 million net gain on divestiture activity for the comparable period of 2011 related to the divestiture of non-strategic oil and gas properties located in our Rocky Mountain region. We will continue to evaluate our portfolio to determine whether there are non-strategic properties we could divest.

Marketed gas system revenue and expense. Marketed gas system revenue decreased $3.2 million to $12.4 million for the quarter ended March 31, 2012, compared with $15.6 million for the same period of 2011 as a result of declining gas prices. Concurrent with the decrease in marketed gas system revenue, marketed gas system expense decreased $5.1 million to $10.9 million for the quarter ended March 31, 2012, compared with $16.0 million for the same period of 2011. Our net margin improved from the prior period as a result of entering into a new processing agreement with reduced fees. We expect that marketed gas system revenue and expense will continue to coincide with increases and decreases in production and our realized gas price.

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Oil, gas, and NGL production expense. Total production costs for the first quarter of 2012 increased 32 percent to $87.1 million compared with $65.8 million for the same period of 2011, as a result of a 40 percent increase in net production volumes on an equivalent basis. Please refer to the caption A three-month overview of selected production and financial information, including trends above for discussion of production costs on a per MCFE basis.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A expense increased $64.2 million, or 61 percent, to $169.6 million for the three-month period ended March 31, 2012, compared with $105.4 million for the same period in 2011, due to an increase in our depreciable asset base as a result of the continued development of our Eagle Ford and Bakken/Three Forks assets. Please refer to the caption A three-month overview of selected production and financial information, including trends above for discussion of DD&A on a per MCFE basis.

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

	For the Three Months Ended March 31,	
	2012	2011
	(in millions)	
Geological and geophysical expenses	$3.9	$2.1
Exploratory dry hole expense	0.6	—
Overhead and other expenses	14.1	10.6
Total	$18.6	$12.7

Exploration expense for the three months ended March 31, 2012, increased 46 percent compared to the same period in 2011. We continue to allocate resources to test current resource plays and assess new exploratory concepts. 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.

Abandonment and impairment of unproved properties. We recorded abandonment and impairment of unproved properties expense of $3.1 million for the three months ended March 31, 2011, associated with lease expirations in our current Mid-Continent region. There was minimal expense recorded in the current quarter of 2012.

General and administrative. General and administrative expense increased $2.2 million to $28.1 million for the three months ended March 31, 2012, compared with $25.9 million for the same period of 2011. The change is due to an increase in employee headcount which resulted in an increase to base compensation, benefits, accruals for cash bonuses, and general corporate office expenses incurred. Please refer to the caption A three-month overview of selected production and financial information, including trends above for discussion of general and administrative expense on a per MCFE basis.

Change in Net Profits Plan liability. This non-cash expense generally relates to the change in the estimated value of the associated liability between reporting periods. Please refer to Note 11 - Fair Value Measurements in Part I, Item 1 of this report for the impact a direct payment to cash-out several pools had on our change in Net Profits Plan liability in 2011. For the quarter ended March 31, 2012, we recorded non-cash expense of $3.9 million compared to expense of $14.2 million for the same period in 2011. The strip prices for oil, gas, and NGLs increased from December 31, 2010, to March 31, 2011, which had the effect of increasing the Net Profits Plan liability between the two periods. Between December 31, 2011, and March 31, 2012, the strip prices for oil increased while strip prices for gas decreased. The result was a smaller increase in the liability between the two periods. Accordingly, the charge in the first quarter of 2012 was smaller compared to that recognized in the corresponding period in 2011. The change in our liability is subject to estimation and may change dramatically from period to period based on assumptions used for production rates, reserve quantities, commodity pricing, discount rates, tax rates, and production costs. Payments made to participants as a result of divestitures will also impact our liability. We broadly expect the change in our Net Profits Plan liability to trend with changes in strip prices.

Unrealized and realized derivative loss. We recognized an unrealized and realized derivative loss of $2.2 million for the first quarter of 2012 compared to a loss of $88.4 million for the same period in 2011. These amounts include the change in fair value on commodity derivative contracts and realized cash settlement gains or losses on derivatives for which unrealized changes in fair value were not previously recorded in AOCIL. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional discussion.

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Income tax benefit (expense). We recorded income tax expense of $15.7 million for the first quarter of 2012 compared to a benefit of $11.1 million for the first quarter of 2011, resulting in effective tax rates of 37.3 percent and 37.4 percent, respectively. The change in income tax expense is a result of the differences in components of net income, primarily a 2011 derivative loss. Projections at the end of the first quarter of 2012 indicate that there will be no current federal income taxes in the current year.

Overview of Liquidity and Capital Resources

We believe that we have sufficient liquidity and capital resources to execute our business plans for the foreseeable future.

Sources of Cash

We currently expect our cash flow from operations and divestiture proceeds will fund the majority of our capital program and our credit facility will be used to fund the remainder. Although we anticipate that our cash flow and borrowing capacity under our credit facility will be sufficient to fund our current capital program, accessing the capital markets is an option if deemed the best solution for our demands. We will continue to evaluate our property base to identify and divest properties we consider non-core to our strategic goals.

Our primary sources of liquidity are the cash flows provided by our operating activities, use of our credit facility, divestitures of properties, and other financing alternatives, including accessing capital markets. 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 broad 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. The borrowing base on our credit facility could be reduced as a result of lower commodity prices or divestitures of producing properties. Historically, decreases in commodity prices have limited our industry’s access to the capital markets.

In late 2011, we consummated our Acquisition and Development Agreement with Mitsui pursuant to which Mitsui funds, or carries, 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 has been expended on our behalf. This carry is expected to be realized over the next three to four years, and as of March 31, 2012, the remaining carry was $618.1 million. Please refer to Note 12 - Acquisition and Development Agreement in Part I, Item 1 of this report for additional information.

Current proposals to fund the federal government budget include eliminating or reducing current tax deductions for intangible drilling costs, domestic production activities, and percentage depletion. Legislation modifying or eliminating these deductions would have the immediate effect of reducing operating cash flows, thereby reducing funding available for our and our peers’ exploration and development capital programs. These funding reductions could have a significant adverse effect on oil and gas drilling in the United States for a number of years.

Credit Facility

In May 2011, we executed our Fourth Amended and Restated Credit Agreement, providing a $2.5 billion senior secured revolving credit facility with a scheduled maturity date of May 27, 2016. Our borrowing base at March 31, 2012, under the credit facility was $1.3 billion. Subsequent to March 31, 2012, our borrowing base was redetermined at $1.5 billion. Our borrowing base is subject to regular semi-annual redeterminations by our lenders and the next scheduled re-determination date is October 1, 2012. As of the filing date of this report our lenders agreed to a current aggregate commitment amount of $1.0 billion. We believe the current commitment amount is sufficient to meet our anticipated liquidity and operating needs. Through the filing date of this report, we have experienced no issues drawing upon our credit facility. No individual bank participating in the credit facility represents more than ten percent of the lending commitments under the credit facility.

We had an outstanding balance under our credit facility of $24.0 million and $57.5 million as of March 31, 2012, and April 27, 2012, respectively. We had letters of credit totaling $808,000 outstanding under our credit facility as of March 31, 2012, and April 27, 2012. Letters of credit reduce the amount available under the credit facility on a dollar-for-dollar basis. We had $975.2 million and $941.7 million of available borrowing capacity under this facility as of March 31, 2012, and April 27, 2012. Our daily weighted-average credit facility debt balance was approximately $600,000 for the three months ended March 31, 2012, compared to $16.5 million for the same period in 2011. Borrowings under our credit facility are secured by mortgages on substantially all of our oil and gas properties.

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Weighted-Average Interest Rates

Our weighted-average interest rates in the current and prior year include cash interest payments, cash fees paid on the unused portion of the credit facility's aggregate commitment amount, letters of credit fees, amortization of the convertible notes debt discount, and amortization of deferred financing costs. Our weighted-average interest rates for the three months ended March 31, 2012, and 2011, were 7.6 percent and 8.4 percent, respectively. The decrease in our weighted-average interest rate from 2011 is a result of our 6.625% Senior Notes and 6.50% Senior Notes being outstanding for the entire quarter ended March 31, 2012, at rates below the average interest rate for the quarter ended March 31, 2011. During the first quarter of 2011, only our 6.625% Senior Notes were outstanding and only for part of the quarter. Our weighted-average borrowing rates for the three months ended March 31, 2012, and 2011, were 5.7 percent and 4.9 percent, respectively. Our weighted-average borrowing rates includes cash interest payments, and excludes cash fees paid on the unused portion of the credit facility's aggregate commitment amount, letter of credit fees, amortization of the convertible notes debt discount, and amortization of deferred financing costs.
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 consolidated earnings before interest, taxes, depreciation, depletion, amortization, and exploration expense of less than 4.0 to 1.0 and an adjusted current ratio, as defined by our credit agreement, of no less than 1.0. As of March 31, 2012, our debt to EBITDAX ratio and adjusted current ratio as defined by our credit agreement, were 1.04 and 2.96, respectively. As of the filing date of this report, we are in compliance with all financial and non-financial covenants under our credit facility.

Uses of Cash
We use cash for the acquisition, exploration, and development of oil and gas properties and for the payment of trade payables, overhead, 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 three months of 2012, we spent $335.0 million for exploration and development capital activities, and leasehold acquisitions. These amounts differ from the cost incurred amounts based on the timing of cash payments associated with these activities as compared to the accrual-based activity upon which the costs incurred amounts are presented.
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 cash flows from operating, investing, and financing activities, and our ability to assimilate acquisitions and execute our drilling program. In addition, the impact of oil, gas, and NGL prices on investment opportunities, the availability of capital and borrowing facilities, 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 regularly 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.
Subsequent to March 31, 2012, we called for redemption all of our outstanding 3.50% Senior Convertible Notes. Please refer to Note 5 - Long-Term Debt in Part I, Item 1 of this report for additional information.

As of the filing date of this report, we have authorization from our Board of Directors to repurchase up to 3,072,184 shares of our common stock under our stock repurchase program. Shares may be repurchased from time to time in open market transactions or privately negotiated transactions, subject to market conditions and other factors, including certain provisions of our credit facility and the indentures governing our 6.625% Senior Notes and 6.50% Senior Notes, compliance with securities laws, and the terms and provisions of our stock repurchase program. We currently do not plan to repurchase shares in 2012.

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The following table presents changes in cash flows between the three-month periods ended March 31, 2012, and 2011. 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 Three Months Ended March 31, 2012 (in millions)	2011	Amount Change Between Periods	Percent Change Between Periods
Net cash provided by operating activities	$188.1	$156.7	$31.4	20%
Net cash (used in) investing activities	$(331.8)	$(273.0)	$(58.8)	22%
Net cash provided by financing activities	$24.8	$302.6	$(277.8)	(92)%

Analysis of Cash Flow Changes Between the Three Months Ended March 31, 2012, and 2011

Operating activities. Cash received from oil, gas, and NGL production revenues, including derivative cash settlement gains of $7.1 million, increased $115.3 million to $372.2 million for the first three months of 2012, compared with $256.9 million for the same period in 2011. The increase was the result of a 38 percent increase in production revenue including derivative cash settlements. Cash paid for lease operating expenses increased $6.0 million to $44.4 million for the first three months of 2012, compared with $38.4 million for the same period in 2011. Cash paid for interest during the first quarter of 2012 increased $10.7 million compared to the same period in 2011 due to interest payments on our 6.625% Senior Notes issued in 2011. We will pay interest on our 6.50% Senior Notes starting in the second quarter of 2012.

Investing activities. Cash outflows for 2012 capital expenditures increased $25.3 million, or eight percent, compared with the same period in 2011. This increase was due to our election to increase drilling activity, which was driven by more favorable oil and NGL prices, an improved overall macro-economic environment, and our successful development activities in our Eagle Ford shale play. Net proceeds from the sale of oil and gas properties decreased $37.3 million between the two periods, as we divested of significantly more properties in the first quarter of 2011 than in the same period in 2012.

Financing activities. We did not receive any proceeds from the issuance of debt in the first quarter of 2012. We received $341.4 million of proceeds from the issuance of our 6.625% Senior Notes in the first quarter of 2011. Net borrowings against our credit facility for the quarter ended March 31, 2012, were $24.0 million compared with net repayments of $48.0 million for the same period of 2011.

Commodity Price Risk and Interest Rate Risk

We are exposed to market risk, which is estimated as the potential change in fair value resulting from an immediate hypothetical one percentage point parallel shift in the yield curve, including the effects of changes in oil, gas, and NGL commodity prices and changes in interest rates. Changes in interest rates can affect the amount of interest we earn on our cash and cash equivalents and the amount of interest we pay on borrowings under our revolving credit facility. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate 3.50% Senior Convertible Notes, our 6.625% Senior Notes, or our 6.50% Senior Notes, but do affect their fair market value. The carrying amount of our floating-rate debt typically approximates its fair value. As of March 31, 2012, we had $24.0 million floating-rate debt outstanding, and our fixed-rate debt outstanding was $987.5 million.

There has been no material change to the oil and gas price sensitivity analysis previously disclosed. Refer to the corresponding section under Part II, Item 7 of our 2011 Form 10-K.

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

Our oil, gas, and NGL derivative contracts include costless swaps and costless collar arrangements. All contracts are entered into for other-than-trading purposes. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional information regarding accounting for our derivative transactions.

As of March 31, 2012, we have derivative positions in place covering a portion of anticipated production through the fourth quarter of 2014 totaling 9.7 million Bbls of oil, 69.9 million MMBtu of gas, and 1.1 million Bbls of NGLs.

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In a typical commodity swap agreement, if the agreed upon published third-party index price is lower than the swap fixed price, we receive the difference between the index price and the agreed upon swap fixed price. If the index price is higher than the swap fixed price, we pay the difference. For collar agreements, we receive the difference between an agreed upon index and the floor price if the index price is below the floor price. We pay the difference between the agreed upon 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 describe the approximate volumes, average contract prices, and fair values of contracts we have in place as of March 31, 2012:

Oil Contracts

Oil Swaps

Contract Period	NYMEX WTI Volumes	Weighted-Average Contract Price	Fair Value at March 31, 2012 (Liability)
	(Bbls)	(per Bbl)	(in millions)
Second quarter 2012	524,000	$84.19	$(10.2)
Third quarter 2012	489,000	$83.87	(10.2)
Fourth quarter 2012	463,000	$87.08	(8.3)
2013	616,000	$88.22	(9.7)
2014	661,000	$91.72	(5.0)
All oil swaps	2,753,000		$(43.4)

Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at March 31, 2012 (Liability)
	(Bbls)	(per Bbl)	(per Bbl)	(in millions)
Second quarter 2012	743,000	$80.78	$112.89	$(0.8)
Third quarter 2012	638,000	$80.35	$112.53	(1.9)
Fourth quarter 2012	566,000	$80.03	$112.28	(2.3)
2013	2,866,000	$78.14	$110.11	(14.7)
2014	2,174,000	$83.71	$107.93	(4.4)
All oil collars	6,987,000			$(24.1)

Gas Contracts

Gas Swaps

Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at March 31, 2012 Asset
	(MMBtu)	(per MMBtu)	(in millions)
Second quarter 2012	7,140,000	$ 4.77	$19.4
Third quarter 2012	6,510,000	$ 4.95	16.9
Fourth quarter 2012	8,424,000	$ 4.57	15.3

2013	20,509,000	$ 4.52	24.2
2014	14,954,000	$ 4.23	5.6
All gas swaps*	57,537,000		$81.4

*Gas swaps are comprised of IF CIG (1%), IF El Paso Permian (1%), IF HSC (33%), IF NGPL MidCont. (1%), IF NGPL TXOK (5%), IF NNG Ventura (1%), IF PEPL (17%), IF Reliant N/S (26%), and IF TETCO STX (15%).

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Gas Collars

Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at March 31, 2012 Asset
	(MMBtu)	(per MMBtu)	(per MMBtu)	(in millions)
2013	6,650,000	$4.39	$5.34	$7.4
2014	5,734,000	$4.38	$5.36	4.5
All gas collars*	12,384,000			$11.9

*Gas collars are comprised of IF HSC (18%), IF NGPL TXCO (18%), IF Reliant N/S (29%), and IF TETCO STX (35%).

NGL Contracts

NGL Swaps

Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at March 31, 2012 (Liability)
	(approx. Bbls)	(per Bbl)	(in millions)
Second quarter 2012	387,000	$ 52.68	$(1.6)
Third quarter 2012	346,000	$ 53.83	(0.8)
Fourth quarter 2012	316,000	$ 53.28	(0.7)
2013	84,000	$ 44.95	(0.8)
All NGL swaps*	1,133,000		$(3.9)

*NGL swaps are comprised of OPIS Mont. Belvieu LDH Propane (27%), OPIS Mont. Belvieu Purity Ethane (34%), OPIS Mont. Belvieu NON-LDH Isobutane (10%), OPIS Mont. Belvieu NON-LDH Natural Gasoline (15%), and OPIS Mont. Belvieu NON-LDH Normal Butane (14%).

Off-Balance Sheet Arrangements

As part of our ongoing business, 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 (“SPE”), which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. As of March 31, 2012, we have not been involved in any unconsolidated SPE transactions.

We evaluate our transactions to determine if any variable interest entities exist. If it is determined that we are the primary beneficiary of a variable interest entity, that entity is consolidated into our consolidated financial statements.

Critical Accounting Policies and Estimates

We refer you to the corresponding section in Part II, Item 7 of our 2011 Form 10-K and to the footnote disclosures included in Part I, Item 1 of this report.

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

EBITDAX represents income or loss before interest expense, interest income, income taxes, depreciation, depletion, amortization and accretion, exploration, property impairments, non-cash stock compensation expense, unrealized derivative losses, change in the Net Profit Plan liability, and gains on divestitures. EBITDAX excludes certain items that we believe affect the comparability of operating results and can exclude items which are generally one-time or whose timing and/or amount cannot be reasonably estimated. EBITDAX is a non-GAAP measure that is presented because we believe that it provides useful additional information to investors, 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 financial covenants based on our debt to EBITDAX ratio under our credit facility. In addition, 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. EBITDAX should not be considered in isolation or as a substitute for net income, income from operations, net cash provided by operating activities, profitability, or liquidity measures prepared under GAAP. Since EBITDAX excludes some, but not all items that affect net income and may vary among companies, the EBITDAX amounts presented may not be comparable to similarly titled measures of other companies. The following table provides a reconciliation of our net income (loss) to EBITDAX for the periods presented:

	Three Months Ended March 31,	
	2012	2011
	(in thousands)	
Net income (loss)	$26,336	$(18,503)
Interest expense	14,278	9,714
Interest income	(70)	(128)
Income tax (benefit) expense	15,681	(11,055)
Depreciation, depletion, amortization, and asset retirement obligation liability accretion	169,570	105,356
Exploration	18,607	12,712
Abandonment and impairment of unproved properties	142	3,079
Stock-based compensation expense	4,350	5,551
Unrealized derivative loss	7,652	82,012
Change in Net Profits Plan liability	3,939	14,195
Gain on divestiture activity	(1,462)	(24,915)
EBITDAX	$259,023	$178,018

Cautionary Information about Forward-Looking Statements

This Form 10-Q contains “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this Form 10-Q 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 Form 10-Q, 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;

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- 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. These risks are described in the Risk Factors section of our 2011 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;
- the continued 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 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 vendors, customers, or contractual counterparties to meet their obligations;

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- 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 our ability 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;
- operating and environmental risks and hazards that could result in substantial losses;
- complex laws and regulations, including environmental regulations, that result in substantial costs and other risks;
- the availability and capacity of gathering, transportation, processing, and/or refining facilities;
- our ability to sell and/or receive market prices for our oil, gas, and NGLs;
- new technologies may cause our current exploration and drilling methods to become obsolete;
- the possibility of security threats, including terrorist attacks and cybersecurity breaches, against, or otherwise impacting, our facilities and systems; and
- litigation, environmental matters, the potential impact of government regulations, and the use of management estimates regarding such matters.

We caution you that forward-looking statements are not guarantees of future performance and that actual results or performance may be materially different from those expressed or implied in the forward-looking statements. The forward-looking statements in this report speak as of the filing date of this report. Although we may from time to time voluntarily update our prior forward-looking statements, we disclaim any commitment to do so except as required by securities laws.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this item is provided under the captions Commodity Price Risk and Interest Rate Risk and Summary of Oil, Gas, and NGL Derivative Contracts in Place in Item 2 above and is incorporated herein by reference. Please refer to the sensitivity analysis within our 2011 Form 10-K in Part II, Item 7.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that are designed to reasonably ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms, and to reasonably ensure that such information is accumulated and communicated to our management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosure.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) ("Disclosure Controls") will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls will be modified as systems change and conditions warrant.

An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these Disclosure Controls are effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There have been no changes during the first quarter of 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

From time to time, we may be involved in litigation relating to claims arising out of our operations in the normal course of business. As of the filing date of this report, no legal proceedings are pending against us that we believe individually or collectively could have a materially adverse effect upon our financial condition, results of operations or cash flows.

We note that approximately 22,000 acres of our approximately 196,000 net acres in the Eagle Ford shale play in South Texas are the subject of a lawsuit captioned W.H. Sutton, et al. vs. St. Mary Land & Exploration Co., et al. instituted in the District Court of Webb County in and for the 49th Judicial District of Texas on May 13, 2010. The plaintiffs claim an aggregate overriding royalty interest of 7.46875% in production attributable to a 1966 oil, gas and mineral lease, and that such overriding royalty interest attaches to subsequent leases currently affecting the acreage that is the subject of the lawsuit, which had been released from the 1966 lease. At the original lease date, the 1966 lease was executed for approximately 40,000 acres. The plaintiffs seek to quiet title to their claimed overriding royalty interest and the recovery of unpaid overriding royalty interest proceeds allegedly due. We believe that the claimed overriding royalty interest has been terminated under the governing agreements and the applicable law, and have contested the plaintiffs' claims. Both parties filed motions for summary judgment, and on February 8, 2011, the District Court issued an order granting plaintiffs' motion for summary judgment and denying our motion for summary judgment. The order granting plaintiffs' motion for summary judgment did not award damages but reserved such determination for final order. We believe that the summary

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judgment is incorrect under the governing agreements and applicable law, and we have appealed the court’s ruling. On September 30, 2011, the District Court entered final judgment for the plaintiffs and awarded damages of approximately $5.1 million, which includes prejudgment interest. The District Court also awarded attorneys fees and costs. We have appealed the District Court’s judgment and obtained a stay pending appeal that prevents the plaintiffs from executing on the judgment.

We believe this lawsuit is entirely without merit and we will continue to vigorously contest this litigation. However, we cannot predict the ultimate outcome of this lawsuit. If the plaintiffs were to ultimately prevail, the overriding royalty interest would have the effect of reducing our net revenue interest in the affected acreage, which would negatively impact our economics in this portion of our acreage, but we do not believe would have a material adverse effect upon our financial condition, results of operations, or cash flows.

We recently filed, in Webb County, Texas, a declaratory judgment action, captioned SM Energy Company vs. W.H. Sutton, et al., seeking a judgment declaring that the 1966 lease terminated with respect to the remaining 18,000 acres, based upon a failure of continuous development, and that any overriding royalty interest claimed by the defendants' has been extinguished.
We and our working interest partners recently filed an action against Endeavour Operating Corporation (“Endeavour”) in Harris County, Texas, captioned SM Energy Company, et al. v. Endeavour Operating Corporation, seeking an order requiring Endeavour to honor its obligations to consummate the purchase of assets located in Pennsylvania, or in the alternative, for damages. We intend to take such reasonable measures as are practicable to attempt to mitigate our potential damages, and subsequent to March 31, 2012, initiated efforts to solicit reasonable offers for such assets. If we are successful in such efforts and complete a sale for less than the $110 million Endeavour agreed to pay, we will continue to prosecute this action to recover any such deficiency and any amounts expended in our efforts to mitigate, and to obtain any other relief to which we are entitled.

With the exception of the above disclosures, there have been no material changes from legal proceedings as previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2011 under Item 3, Part I. See Note 6 - Commitments and Contingencies, in Part I, Item 1 of this report, for additional discussion.

ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors as previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2011.

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ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

(c) The following table provides information about purchases by the Company or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the fiscal quarter ended March 31, 2012, of shares of the Company's common stock, which is the sole class of equity securities registered by the Company pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased [1]	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Program	(d) Maximum Number of Shares that May Yet Be Purchased Under the Program [2]
01/01/12 - 01/31/12	—	$—	—	3,072,184
02/01/12 - 02/29/12	—	$—	—	3,072,184
03/01/12 - 03/31/12	176	$79.73	—	3,072,184
Total:	176	$79.73	—	3,072,184

(1) All shares purchased in 2012 were to offset tax withholding obligations that occur upon the delivery of outstanding shares underlying RSUs and PSUs delivered under the terms of grants under our Equity Incentive Compensation Plan.

(2) In July 2006, our Board of Directors approved an increase in the number of shares that may be repurchased under the original August 1998 authorization to 6,000,000 as of the effective date of the resolution. Accordingly, as of the date of this filing, we may repurchase up to 3,072,184 shares of common stock on a prospective basis. The shares may be repurchased from time to time in open market transactions or privately negotiated transactions, subject to market conditions and other factors, including certain provisions of our credit facility, the indentures governing our 6.625% Senior Notes and 6.50% Senior Notes and compliance with securities laws. Stock repurchases may be funded with existing cash balances, internal cash flow, or borrowings under our credit facility. The stock repurchase program may be suspended or discontinued at any time.

Our payment of cash dividends to our stockholders is subject to covenants in our credit facility that limit our annual dividend payment to no more than $50.0 million per year. We are also subject to certain covenants under our 6.625% Senior Notes and 6.50% Senior Notes that restrict certain payments, including dividends; provided, however, the first $6.5 million of dividends paid each year are not restricted by these covenants. We do not anticipate that these restrictions will limit our payment of dividends at our current rate for the foreseeable future.

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ITEM 6. EXHIBITS

The following exhibits are filed or furnished with or incorporated by reference into this report:

Exhibit	Description
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes - Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes - Oxley Act of 2002
32.1**	Certification pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002
101.INS****	XBRL Instance Document
101.SCH****	XBRL Schema Document
101.CAL****	XBRL Calculation Linkbase Document
101.LAB****	XBRL Label Linkbase Document
101.PRE****	XBRL Presentation Linkbase Document
101.DEF****	XBRL Taxonomy Extension Definition Linkbase Document

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*	Filed with this report.
**	Furnished with this report.
****	Furnished, not filed. Users of this data submitted electronically herewith are advised pursuant to Rule 406T of Regulation S-T that this interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections.

SIGNATURES

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

	SM ENERGY COMPANY
May 3, 2012	By: /s/ ANTHONY J. BEST Anthony J. Best President and Chief Executive Officer
May 3, 2012	By: /s/ A. WADE PURSELL A. Wade Pursell Executive Vice President and Chief Financial Officer
May 3, 2012	By: /s/ MARK T. SOLOMON Mark T. Solomon Vice President and Controller