SUPREME INDUSTRIES INC
Form 10-Q
August 14, 2006

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended July 1, 2006

OR

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

For the transition period from to

Commission File No. 1-8183

SUPREME INDUSTRIES, INC.

(Exact name of registrant as specified in its charter)

Delaware	**75-1670945**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

2581 E. Kercher Rd., P.O. Box 237, Goshen, Indiana 46528

(Address of principal executive offices)

Registrant s telephone number, including area code: **(574) 642-3070**

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 x No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act (check one):

Large accelerated filer o Accelerated filer o Non-accelerated filer x

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No x

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

Common Stock ($.10 Par Value)	**Outstanding at July 25, 2006**
Class A	**10,585,826**
Class B	**2,109,133**

SUPREME INDUSTRIES, INC.

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS.

Supreme Industries, Inc. and Subsidiaries

Consolidated Balance Sheets

	July 1, 2006 (Unaudited)	December 31, 2005
Assets		
Current assets:		
Cash and cash equivalents	$ 398,411	$ 1,515,532
Investments	2,401,379	1,168,922
Accounts receivable, net	33,181,607	29,594,819
Inventories	50,627,371	50,730,205
Other current assets	2,075,217	5,600,299
Total current assets	88,683,985	88,609,777
Property, plant and equipment, at cost	88,690,958	86,801,354
Less, Accumulated depreciation and amortization	41,205,964	39,343,641
Property, plant and equipment, net	47,484,994	47,457,713
Goodwill and intangible assets, net	1,426,833	735,014
Other assets	938,017	549,350
Total assets	$ 138,533,829	$ 137,351,854

The accompanying notes are a part of the consolidated financial statements.

	July 1, 2006 (Unaudited)	December 31, 2005
Liabilities and Stockholders Equity		
Current liabilities:		
Current maturities of long-term debt	$ 1,835,346	$ 1,816,092
Trade accounts payable	15,657,655	15,675,073
Accrued income taxes	119,478	380,721
Other accrued liabilities	9,360,768	9,947,870
Total current liabilities	26,973,247	27,819,756
Long-term debt	32,470,366	31,378,367
Deferred income taxes	3,136,475	2,988,275
Total liabilities	62,580,088	62,186,398
Stockholders equity	75,953,741	75,165,456
Total liabilities and stockholders equity	$ 138,533,829	$ 137,351,854

The accompanying notes are a part of the consolidated financial statements.

Supreme Industries, Inc. and Subsidiaries

Consolidated Statements of Income (Unaudited)

	Three Months Ended July 1, 2006	June 25, 2005	Six Months Ended July 1,	June 25,
			1,144,972	1,042,123
Accumulated other comprehensive loss	(10,604)	(15,482)		
Total stockholders equity	1,349,166	1,218,526		
Total Liabilities and Stockholders Equity	**$ 3,219,893**	**$ 2,744,321**		

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

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SM ENERGY COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)

(In thousands, except per share amounts)

	For the Three Months Ended June 30, 2011	For the Three Months Ended June 30, 2010	For the Six Months Ended June 30, 2011	For the Six Months Ended June 30, 2010
Operating revenues and other income:				
Oil, gas, and NGL production revenue	$ 333,934	$ 175,887	$ 610,247	$ 388,774
Realized hedge gain (loss) (note 10)	(6,330)	9,329	(7,705)	11,924
Gain on divestiture activity (note 3)	30,019	7,021	54,934	127,999
Marketed gas system and other operating revenue	20,250	19,460	35,726	43,135
Total operating revenues and other income	377,873	211,697	693,202	571,832
Operating expenses:				
Oil, gas, and NGL production expense	53,342	45,168	119,154	93,508
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	115,382	79,770	220,738	157,535
Exploration	9,603	14,498	22,315	28,396
Abandonment and impairment of unproved properties	1,237	2,375	4,316	3,279
General and administrative	27,310	25,398	53,171	48,884
Change in Net Profits Plan liability	(13,984)	(6,599)	211	(33,871)
Unrealized and realized derivative (gain) loss (note 10)	(43,876)	(2,087)	44,553	(9,822)
Marketed gas system and other expense	17,152	16,385	37,009	39,383
Total operating expenses	166,166	174,908	501,467	327,292
Income from operations	211,707	36,789	191,735	244,540
Nonoperating income (expense):				
Interest income	227	54	355	183
Interest expense	(14,550)	(6,343)	(24,264)	(13,130)
Income before income taxes	197,384	30,500	167,826	231,593
Income tax expense	(72,851)	(12,432)	(61,796)	(87,347)
Net income	**$ 124,533**	**$ 18,068**	**$ 106,030**	**$ 144,246**
Basic weighted-average common shares outstanding	63,638	62,917	63,543	62,855
Diluted weighted-average common shares outstanding	66,909	64,566	66,695	64,493
Basic net income per common share	**$ 1.96**	**$ 0.29**	**$ 1.67**	**$ 2.29**
Diluted net income per common share	**$ 1.86**	**$ 0.28**	**$ 1.59**	**$ 2.24**

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

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SM ENERGY COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY AND COMPREHENSIVE INCOME (UNAUDITED)

(In thousands, except share amounts)

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Treasury Stock Shares	Treasury Stock Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders Equity
Balances, January 1, 2011	**63,412,800**	**$ 634**	**$ 191,674**	**(102,635)**	**$ (423)**	**$ 1,042,123**	**$ (15,482)**	**$ 1,218,526**
Comprehensive income, net of tax:								
Net income						106,030		106,030
Reclassification to earnings							4,878	4,878
Total comprehensive income								110,908
Cash dividends, $ 0.05 per share						(3,181)		(3,181)
Issuance of common stock under Employee Stock Purchase Plan	22,373	1	1,121					1,122
Issuance of common stock upon vesting of RSUs, net of shares used for tax withholdings, including income tax benefit of RSUs	18,836		(644)					(644)
Sale of common stock, including income tax benefit of stock option exercises	310,412	3	10,595					10,598
Stock-based compensation expense			12,958	21,568	(1,121)			11,837
Balances, June 30, 2011	**63,764,421**	**$ 638**	**$ 215,704**	**(81,067)**	**$ (1,544)**	**$ 1,144,972**	**$ (10,604)**	**$ 1,349,166**
Balances, January 1, 2010	**62,899,122**	**$ 629**	**$ 160,516**	**(126,893)**	**$ (1,204)**	**$ 851,583**	**$ (37,954)**	**$ 973,570**
Comprehensive income, net of tax:								
Net income						144,246		144,246
Change in derivative instrument fair value							53,765	53,765
Reclassification to earnings							(782)	(782)
Minimum pension liability adjustment							4	4
Total comprehensive income								197,233
Cash dividends, $ 0.05 per share						(3,144)		(3,144)
Issuance of common stock under Employee Stock Purchase Plan	27,456		799					799
Issuance of common stock upon vesting of RSUs, net of shares used for tax withholdings, including income tax cost of RSUs	34,588	1	(545)					(544)
	148,902	1	3,054					3,055

Sale of common stock, including income tax benefit of stock option exercises								
Stock-based compensation expense			11,149	24,258	715			11,864
Balances, June 30, 2010	**63,110,068**	**$ 631**	**$ 174,973**	**(102,635)**	**$ (489)**	**$ 992,685**	**$ 15,033**	**$ 1,182,833**

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

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SM ENERGY COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(In thousands)

	For the Six Months Ended June 30, 2011	2010
Cash flows from operating activities:		
Net income	$ 106,030	$ 144,246
Adjustments to reconcile net income to net cash provided by operating activities:		
Gain on divestiture activity	(54,934)	(127,999)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	220,738	157,535
Exploratory dry hole expense	49	327
Abandonment and impairment of unproved properties	4,316	3,279
Stock-based compensation expense	11,837	11,864
Change in Net Profits Plan liability	211	(33,871)
Unrealized derivative (gain) loss	24,160	(9,822)
Amortization of debt discount and deferred financing costs	11,294	6,657
Deferred income taxes	52,241	78,820
Plugging and abandonment	(1,430)	(6,222)
Other	(5,888)	2,937
Changes in current assets and liabilities:		
Accounts receivable	(10,370)	7,628
Refundable income taxes	5,348	9,558
Prepaid expenses and other	15,692	(148)
Accounts payable and accrued expenses	(2,530)	26,299
Excess income tax benefit from the exercise of stock awards	(6,791)	(938)
Net cash provided by operating activities	**369,973**	**270,150**
Cash flows from investing activities:		
Net proceeds from sale of oil and gas properties	97,952	247,998
Capital expenditures	(662,372)	(304,627)
Deposits to restricted cash		(19,595)
Other	(2,355)	(6,492)
Net cash used in investing activities	**(566,775)**	**(82,716)**
Cash flows from financing activities:		
Proceeds from credit facility	102,000	204,059
Repayment of credit facility	(150,000)	(392,059)
Debt issuance costs related to credit facility	(8,525)	
Net proceeds from 6.625% Senior Notes	341,435	
Proceeds from sale of common stock	4,929	2,916
Dividends paid	(3,181)	(3,144)
Excess income tax benefit from the exercise of stock awards	6,791	938
Other	(644)	(544)
Net cash provided by (used in) financing activities	**292,805**	**(187,834)**
Net change in cash and cash equivalents	96,003	(400)
Cash and cash equivalents at beginning of period	5,077	10,649
Cash and cash equivalents at end of period	**$ 101,080**	**$ 10,249**

The accompanying notes are an integral part of these 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 noncash investing and financing activities:

	For the Six Months Ended June 30, 2011 (In thousands)	2010
Cash paid for interest	$ (6,378)	$ (8,152)
Net cash refunded for income taxes	$ 2,543	$ 2,392

As of June 30, 2011, and 2010, $237.9 million, and $105.4 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 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, exploitation, development, and production of crude oil, natural gas, and natural gas liquids (NGLs) in North America, with a focus on oil and liquids-rich resource plays.

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

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements of SM Energy have been prepared in accordance with accounting principles generally accepted in the United States 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 generally accepted accounting principles 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, 2010, (the 2010 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 June 30, 2011, 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 2010 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 2010 Form 10-K. As discussed in Note 10 - Derivative Financial Instruments, as of January 1, 2011, the Company elected to discontinue cash flow hedge accounting on a prospective basis.

Recently Issued Accounting Standards

In May 2011, the Financial Accounting Standards Board (FASB) issued new fair value measurement authoritative guidance that clarifies the application of fair value measurement and disclosure requirements and changes particular principles or requirements for measuring fair value. This guidance is effective for annual periods beginning after December 15, 2011. The Company is currently evaluating the provisions of this guidance and assessing the impact, if any, it may have on the Company s fair value disclosures.

In June 2011, the FASB issued new authoritative guidance that states an entity that reports items of other comprehensive income has the option to present the components of net income and comprehensive income in either one continuous financial statement, or two consecutive financial statements. This guidance is effective for annual periods beginning after December 15, 2011. The Company is currently evaluating the provisions of this guidance and assessing the impact it will have on the Company s comprehensive income disclosures.

Note 3 - Divestitures and Assets Held for Sale

Mid-Continent Divestiture

In June 2011, the Company completed the divestiture of certain non-strategic Constitution Field assets located in its Mid-Continent region that were classified as assets held for sale at March 31, 2011. Total cash received, before marketing costs and Net Profits Interest Bonus Plan (Net Profits Plan) payments, was $35.7 million. The final sale price is subject to post-closing adjustments and is expected to be finalized during the second half of 2011. The estimated gain on this divestiture was approximately $28.5 million and may be impacted by the post-closing adjustments mentioned above. The Company determined that the sale did not qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

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Rocky Mountain Divestiture

In January 2011, the Company completed the divestiture of certain non-strategic assets located in its Rocky Mountain region that were classified as assets held for sale at December 31, 2010. Total cash received, before marketing costs and Net Profits Plan payments, was $45.5 million. The final gain on sale related to the divestiture was $27.2 million. The Company determined that the sale did not qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

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 that 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 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 assets for which fair value is determined to be less than the carrying value of the assets.

As of June 30, 2011, the accompanying condensed consolidated balance sheets (accompanying balance sheets) include $130.1 million in book value of assets held for sale, net of accumulated depletion, depreciation and amortization and a corresponding asset retirement obligation liability is also separately presented. The above assets held for sale and asset retirement obligation liability amounts include certain assets located in Pennsylvania and the Company s South Texas & Gulf Coast region, including our gathering assets as described in Note 12 Acquisition and Development Agreement. The Company determined that these planned asset sales do not qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

In July 2011, the Company entered into an agreement to divest its Marcellus shale assets located in Pennsylvania that were classified as held for sale at June 30, 2011, for $80.0 million in cash, subject to normal closing and post-closing adjustments. The agreement has an effective date of April 1, 2011, and is anticipated to close in the third quarter of 2011. The closing of this transaction is subject to the satisfaction of certain closing conditions, including the resolution of any title and environmental defects exceeding specified levels.

On August 2, 2011, the Company divested its operated LaSalle and Dimmitt County assets located in its South Texas & Gulf Coast region that were classified as assets held for sale at June 30, 2011. Total cash received, before marketing costs, was $227.4 million. The final sales price is subject to post-closing adjustments and is expected to be finalized in the fourth quarter of 2011. The estimated gain on this divestiture is approximately $196.1 million and may be impacted by the post-closing adjustments mentioned above.

Note 4 - Income Taxes

Income tax expense for the six-month periods ended June 30, 2011, and 2010, 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, and other permanent differences.

The provision for income taxes consists of the following:

	For the Three Months Ended June 30, 2011	For the Three Months Ended June 30, 2010	For the Six Months Ended June 30, 2011	For the Six Months Ended June 30, 2010
	(in thousands)			
Current portion of income tax (expense) benefit:				
Federal	$ (2,212)	$ 1,759	$ (9,156)	$ (8,216)
State	(224)	21	(399)	(311)
Deferred portion of income tax (expense)	(70,415)	(14,212)	(52,241)	(78,820)
Total income tax (expense)	$ (72,851)	$ (12,432)	$ (61,796)	$ (87,347)
Effective tax rate	36.9%	40.8%	36.8%	37.7%

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. The cumulative effects of state rate changes are reflected in the period legislation is enacted. Changes in the effective tax rate between periods also occur due to estimates for the domestic production activities deduction, percentage depletion, and for potential permanent state tax items that affect the presented periods differently due to oil and gas price variability and the impact of non-core asset sales. The quarterly rate can also be impacted by the proportion of income earned in reported periods.

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The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction and in various states. With few 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 the anticipated $5.5 million refund from its 2006 tax year as a result of a net operating loss carryback claim from the 2008 tax year. In the fourth quarter of 2010, the Internal Revenue Service initiated an audit of the Company for the 2009 tax year. The audit was concluded in the second quarter of 2011 with a $110,000 decrease to the total 2005 refund claim of $25 million. A quick refund claim of $22.9 million from 2005 was received in the third quarter of 2010. The Company s remaining refundable income tax balance at June 30, 2011, includes the remaining $2 million 2005 amount.

Note 5 - Long-Term Debt

Revolving Credit Facility

The Company executed a Fourth Amended and Restated Credit Agreement on May 27, 2011. This amended revolving credit facility replaced the Company s previous facility. The Company incurred $8.5 million of deferred financing costs in association with the amended credit facility. Borrowings under the facility are secured by substantially all of the Company s proved oil and gas properties. The credit facility has a maximum loan amount of $2.5 billion, with current aggregate lender commitments of $1.0 billion, and a maturity date of May 27, 2016. The borrowing base under the credit facility as of the filing date of this report is $1.3 billion, and is subject to regular semi-annual redeterminations. The borrowing base redetermination process considers the value of the Company s oil and gas properties and other assets, as determined by the bank syndicate.

The Company must comply with certain financial and non-financial covenants under the terms of its credit facility agreement, including the limitation of the Company s dividends to no more than $50.0 million per year. The Company was in compliance with all financial and non-financial covenants under the credit facility as of June 30, 2011, and through the filing date of this report. Interest and commitment fees are accrued based on the borrowing base utilization grid below. Eurodollar loans accrue interest at the London Interbank Offered Rate plus the applicable margin from the utilization table below, and Alternative Base Rate (ABR) and swingline loans accrue interest at Prime plus the applicable margin from the utilization table below. Commitment fees are accrued on the unused portion of the aggregate commitment amount and are included in interest expense in the accompanying condensed consolidated statements of operations (accompanying statements of operations).

Borrowing Base Utilization Grid

Borrowing Base Utilization Percentage	**<25%**	**≥25% <50%**	**≥50% <75%**	**≥75% <90%**	**≥90%**
Eurodollar Loans	1.500%	1.750%	2.000%	2.250%	2.500%
ABR Loans or Swingline Loans	0.500%	0.750%	1.000%	1.250%	1.500%
Commitment Fee Rate	0.375%	0.375%	0.500%	0.500%	0.500%

The Company had no outstanding borrowings under its credit facility as of June 30, 2011. The Company had $48.0 million of outstanding borrowings under its previous credit facility as of December 31, 2010. The Company had $999.4 million available borrowing capacity under this facility as of June 30, 2011. The Company had $629.5 million available borrowing capacity under its previous facility as of December 31, 2010, when the aggregate commitment amount was $678.0 million. The Company has two letters of credit outstanding for a total of $608,000 as of June 30, 2011. The Company had a single letter of credit outstanding in the amount of $483,000 at December 31, 2010. These letters of credit reduce the amount available under the commitment amount on a dollar-for-dollar basis.

6.625% Senior Notes Due 2019

On February 7, 2011, the Company issued $350.0 million in aggregate principal amount of 6.625% Senior Notes Due 2019 (the 6.625% Senior Notes). The 6.625% Senior Notes were issued at par and mature on February 15, 2019. The Company received net proceeds of approximately $341.4 million after deducting fees of approximately $8.6 million, which will be amortized as deferred financing costs over the life of the 6.625% Senior Notes. The net proceeds were used to repay all borrowings under the Company s credit facility, with the remainder to be used for the Company s ongoing capital expenditure program and general corporate purposes.

Prior to February 15, 2014, the Company may redeem up to 35 percent of the aggregate principal amount of the 6.625% Senior Notes with the net cash proceeds of one or more equity offerings at a redemption price of 106.625% of the principal amount thereof, plus accrued and unpaid interest. The Company may redeem the 6.625% Senior Notes, in whole or part, at any time prior to February 15, 2015, at a redemption price equal to 100% of the principal amount, plus a specified make whole premium and accrued and unpaid interest.

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The Company may also redeem all or, from time to time, a portion of the 6.625% Senior Notes on or after February 15, 2015, at the prices set forth below, expressed as a percentage of the principal amount redeemed, plus accrued and unpaid interest:

2015	103.313%
2016	101.656%
2017 and thereafter	100.000%

The 6.625% Senior Notes are unsecured senior obligations and rank equal in right of payment with all of the Company s existing and any future unsecured senior debt and are senior in right of payment to any future subordinated debt. There are no subsidiary guarantors of the 6.625% Senior Notes. The Company is subject to certain covenants under its 6.625% Senior Notes that limit incurring additional indebtedness, issuing preferred stock, and making restricted payments in excess of specified amounts. The restricted payment covenant limits the payment of dividends on the Company s common stock, provided however, the Company may pay dividends of up to $6.5 million for any given year during the eight-year term of the notes. The Company is in compliance with all covenants under its 6.625% Senior Notes as of June 30, 2011, and through the filing date of this report.

Additionally, on February 7, 2011, the Company entered into a registration rights agreement that provides holders of the 6.625% Senior Notes certain registration rights for the 6.625% Senior Notes under the Securities Act of 1933, as amended (the Securities Act). Pursuant to the registration rights agreement, the Company will file an exchange offer registration statement with the Securities and Exchange Commission (the SEC) with respect to an offer to exchange the 6.625% Senior Notes for substantially identical notes that are registered under the Securities Act. Under certain circumstances, in lieu of a registered exchange offer, the Company has agreed to file a shelf registration statement relating to the resale of the 6.625% Senior Notes. If the exchange offer is not completed on or before February 7, 2012, or the shelf registration statement, if required, is not declared effective within the time periods specified in the registration rights agreement, then the Company has agreed to pay additional interest with respect to the 6.625% Senior Notes in an amount not to exceed one percent of the principal amount of the 6.625% Senior Notes until the exchange offer is completed or the shelf registration statement is declared effective.

3.50% Senior Convertible Notes Due 2027

On April 4, 2007, the Company issued $287.5 million in aggregate principal amount of 3.50% Senior Convertible Notes Due 2027 (the 3.50% Senior Convertible Notes). The 3.50% Senior Convertible Notes mature on April 1, 2027, unless converted prior to maturity, redeemed, or purchased by the Company.

Holders of the 3.50% Senior Convertible Notes may elect to surrender all or a portion of their notes for conversion under certain circumstances, including during a calendar quarter if the closing price of the Company s common stock was more than 130 percent of the conversion price of $54.42 per share for at least 20 trading days in the 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter. As of December 31, 2010, the 3.50% Senior Convertible Notes were not convertible. The closing price of the Company s common stock was more than the conversion trigger price of $70.75 per share for at least 20 trading days in the 30 consecutive trading days ending on the last trading day during the first quarter of 2011. Therefore the holders of the 3.50% Senior Convertible Notes had the right to convert all or a portion of their notes during the second quarter of 2011. If holders elect to convert all or a portion of their notes during a calendar quarter that they are eligible to do so, they will receive cash, shares of the Company s common stock, or any combination thereof as may be elected by the Company under the indenture for the 3.50% Senior Convertible Notes. No holders elected to convert their notes during the second quarter of 2011. The closing price of the Company s common stock was not more than the conversion trigger price of $70.75 per share for at least 20 trading days in the 30 consecutive trading days ending on the last trading day in the second quarter of 2011. Therefore, the 3.50% Senior Convertible Notes will not be convertible during the third quarter of 2011.

Note 6 - Earnings per Share

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

Diluted net income per common share of stock is calculated by dividing adjusted net income by the number of diluted weighted-average common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist of unvested restricted stock units (RSUs), in-the-money outstanding options to purchase the Company s common stock, contingent Performance Share Awards (PSAs), and shares into which the 3.50% Senior Convertible Notes are convertible.

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The PSAs represent the right to receive, upon settlement of the PSAs after the 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 PSAs granted on the award date. The number of potentially dilutive shares related to PSAs is based on the number of shares, if any, which 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 PSAs, please refer to Note 8 - Compensation Plans under the heading *Performance Share Awards Under the Equity Incentive Compensation Plan*.

The Company s 3.50% Senior Convertible Notes have a net-share settlement right whereby the Company has the option to irrevocably elect, by notice to the trustee under the indenture for the notes, to settle the Company s obligation to deliver shares of the Company s common stock, 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. For accounting purposes, the treasury stock method is used to measure the potentially dilutive impact of shares associated with this conversion feature. Shares of the Company s common stock traded at an average closing price exceeding the $54.42 conversion price for the three-month and six-month periods ended June 30, 2011. The 3.50% Senior Convertible Notes had a dilutive impact for the three-month and six-month periods ended June 30, 2011, as calculated in the basic and diluted earnings per share table below. The 3.50% Senior Convertible Notes were not dilutive for the three-month and six-month periods ended June 30, 2010.

The treasury stock method is used to measure the dilutive impact of unvested RSUs, contingent PSAs, and in-the-money stock options, as calculated in the basic and diluted earnings per share table below.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
	(in thousands, except per share amounts)			
Net income	$ 124,533	$ 18,068	$ 106,030	$ 144,246
Basic weighted-average common shares outstanding	63,638	62,917	63,543	62,855
Add: dilutive effect of stock options, unvested RSUs, and contingent PSAs	2,182	1,649	2,161	1,638
Add: dilutive effect of 3.50% Senior Convertible Notes	1,089		991	
Diluted weighted-average common shares outstanding	66,909	64,566	66,695	64,493
Basic net income per common share	$ 1.96	$ 0.29	$ 1.67	$ 2.29
Diluted net income per common share	$ 1.86	$ 0.28	$ 1.59	$ 2.24

Note 7 - Commitments and Contingencies

During the second quarter of 2011, the Company entered into two natural gas gathering and services agreements whereby it is subject to certain natural gas gathering through-put commitments for up to ten years pursuant to each contract. The Company may be required to make periodic deficiency payments for any shortfalls in delivering the minimum applicable annual or semi-annual volume commitments. In the event that no gas is delivered pursuant to the agreements, the aggregate deficiency payments will total approximately $729.4 million. If a shortfall in the minimum volume commitment arises, the Company can arrange for third party gas to be delivered into the applicable gathering system and applied to the Company s minimum commitment.

During the first quarter of 2011, the Company entered into a hydraulic fracturing services contract. The total commitment is $180.0 million over a two-year term commencing January 1, 2011. However, the Company s liability in the event of early termination of this contract is not to exceed $24.0 million.

The Company is subject to litigation and claims that have arisen in the ordinary course of its business. The Company accrues for such items when a liability is probable and the amount can be reasonably estimated. The Company currently has no such accruals. In the opinion of management, any adverse results in any 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.

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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 has 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 intends to appeal and continue to contest the litigation. In July 2011, the court entered judgment awarding the plaintiffs damages of approximately $5.2 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 8 - Compensation Plans

Cash Bonus Plan

During the first quarters of 2011 and 2010, the Company paid $21.6 million and $7.7 million for cash bonuses earned in the 2010 and 2009 performance years, respectively. Within the general and administrative expense and exploration expense line items in the accompanying statements of operations was $3.7 million and $2.9 million of accrued cash bonus plan expense related to the specific performance year for the three-month periods ended June 30, 2011, and 2010, respectively, and $7.5 million and $6.0 million for the six-month periods ended June 30, 2011, and 2010, respectively.

Performance Share Awards Under the Equity Incentive Compensation Plan

PSAs are the primary form of long-term equity incentive compensation for the Company. The PSA factor is based on the Company s performance after completion of a three-year performance period. The performance criteria for the PSAs 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. In addition, there are separate employment service vesting provisions. PSAs are recognized as general and administrative and exploration expense over the vesting period of the award.

Total stock-based compensation expense related to PSAs for the three-month periods ended June 30, 2011, and 2010, was $4.1 million and $3.8 million, respectively, and $8.4 million and $7.4 million for the six-month periods ended June 30, 2011, and 2010, respectively. As of June 30, 2011, there was $13.6 million of total unrecognized compensation expense related to unvested PSAs that is being amortized through 2013.

A summary of the status and activity of PSAs for the six-month period ended June 30, 2011, is presented in the following table:

	PSAs	Weighted-Average Grant-Date Fair Value

Non-vested, at January 1, 2011	1,110,666	$	39.48
Granted		$	
Vested (1)	(7,682)	$	36.69
Forfeited	(23,289)	$	39.41
Non-vested, at June 30, 2011	1,079,695	$	39.50

(1) The number of awards vested assumes a multiplier of one. The final number of shares vested may vary depending on the ending three-year multiplier, which ranges from zero to two.

Subsequent to June 30, 2011, the Company granted 234,308 Performance Stock Units (PSUs), which are structurally the same as previously granted PSAs, as part of its regular annual compensation process. These PSUs will vest 1/7th on July 1, 2012, 2/7ths on July 1, 2013, and 4/7ths on July 1, 2014. Also subsequent to June 30, 2011, the Company settled 305,351 PSAs that relate to awards granted in 2008 through the issuance of shares of the Company s common stock in accordance with the terms of the PSA awards.

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Restricted Stock Units Under the Equity Incentive Compensation Plan

An RSU represents a right to receive one share of the Company s common stock to be delivered upon settlement of the RSU when it vests. Total RSU compensation expense for the three-month periods ended June 30, 2011, and 2010, was $985,000 and $1.7 million, respectively, and $2.0 million and $3.5 million for the six-month periods ended June 30, 2011, and 2010, respectively. As of June 30, 2011, there was $4.5 million of total unrecognized compensation expense related to unvested RSU awards that is being amortized through 2013.

During the first half of 2011, the Company settled 27,714 RSUs that relate to awards granted in 2008 through the issuance of shares of the Company s common stock in accordance with the terms of the RSU awards. As a result, the Company issued a net of 18,836 shares of common stock associated with these grants. The remaining 8,878 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon delivery of the shares underlying those RSUs.

A summary of the status and activity of RSUs for the six-month period ended June 30, 2011, is presented in the following table:

	RSUs		Weighted-Average Grant-Date Fair Value
Non-vested, at January 1, 2011	333,359	$	31.16
Granted	8,287	$	60.33
Vested	(27,714)	$	37.84
Forfeited	(6,638)	$	29.88
Non-vested, at June 30, 2011	307,294	$	31.37

Subsequent to June 30, 2011, the Company granted 78,165 RSUs, as part of its regular annual compensation process. These RSUs will vest 1/7th on July 1, 2012, 2/7ths on July 1, 2013, and 4/7ths on July 1, 2014. Also subsequent to June 30, 2011, the Company settled 77,602 RSUs that relate to awards granted in 2010 and 2009 through the issuance of shares of the Company s common stock in accordance with the terms of the RSU awards.

Stock Option Grants Under Prior Stock Option Plans

The following table summarizes stock option activity for the six months ended June 30, 2011:

	Options		Weighted-Average Exercise Price		Aggregate Intrinsic Value
Outstanding, January 1, 2011	920,765	$	13.11	$	42,192,057
Exercised	(310,412)	$	12.26		
Forfeited		$			

Outstanding, June 30, 2011	610,353	$	13.54	$	36,586,971
Vested and exercisable, June 30, 2011	610,353	$	13.54	$	36,586,971

As of June 30, 2011, there was no unrecognized compensation expense related to stock option awards.

Director Shares

During the six months ended June 30, 2011, and 2010, the Company issued 21,568 and 24,258 shares, respectively, of the Company s common stock from treasury to the Company s non-employee directors. The shares were issued pursuant to the Company s Equity Incentive Compensation Plan. The Company recorded $1.0 million and $690,000 of compensation expense for the three-month periods ended June 30, 2011, and 2010, respectively, and $1.0 million and $715,000 for the six-month periods ended June 30, 2011, and 2010, respectively.

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Employee Stock Purchase Plan

Under the Company s Employee Stock Purchase Plan (the ESPP), eligible employees may purchase shares of the Company s common stock through payroll deductions of up to 15 percent of eligible compensation. The purchase price of the stock is 85 percent of the lower of the fair market value of the stock on the first or last day of the purchase period. Shares issued under the ESPP, on or after July 1, 2011, have no restriction period. The ESPP is intended to qualify under Section 423 of the Internal Revenue Code. The Company has set aside 2,000,000 shares of its common stock to be available for issuance under the ESPP, of which 1,392,954 shares are available for issuance as of June 30, 2011. There were 22,373 and 27,456 shares issued under the ESPP during the first half of 2011 and 2010, respectively, with a six month restriction period. The fair value of ESPP grants is measured at the date of grant using the Black-Scholes option-pricing model.

Net Profits Plan

Under the Company s Net Profits Plan, all oil and gas wells that were completed or acquired during a year were designated within a specific pool. Key employees recommended by senior management and designated as participants by the Compensation Committee of the Company s Board of Directors (Board) and employed by the Company on the last day of that year became entitled to payments under the Net Profits Plan after the Company had received net cash flows returning 100 percent of all costs associated with that pool. Thereafter, ten percent of future net cash flows generated by the pool are allocated among the participants and distributed at least annually. The portion of net cash flows from a pool to be allocated among the participants increases to 20 percent after the Company has recovered 200 percent of the total costs for the pool, including payments made under the Net Profits Plan at the ten percent level. In December 2007, the Board discontinued the creation of new pools under the Net Profits Plan. As a result, the 2007 Net Profits Plan pool was the last pool established by the Company.

Cash payments made or accrued under the 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 June 30,		For the Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
	(in thousands)			
General and administrative expense	$ 5,261	$ 5,381	$ 10,591	$ 12,315
Exploration expense	585	667	1,062	1,258
Total	$ 5,846	$ 6,048	$ 11,653	$ 13,573

Additionally, the Company accrued or made cash payments under the Net Profits Plan of $2.0 million and $1.9 million for the three months ended June 30, 2011, and 2010, respectively, and $6.3 million and $20.1 million for the six months ended June 30, 2011, and 2010, respectively, as a result of divestiture proceeds. The cash payments are accounted for as a reduction of 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 did allocate 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 benefit would predominately be allocated to general and administrative expense. The amount that would be allocated to exploration expense is minimal in comparison. As time progresses, less of the distributions relate to prospective exploration efforts as more of the distributions are made to employees that have terminated employment and do not provide ongoing exploration support to the Company.

Note 9 - 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).

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Components of Net Periodic Benefit Cost for Both 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 June 30, 2011	For the Three Months Ended June 30, 2010	For the Six Months Ended June 30, 2011	For the Six Months Ended June 30, 2010
	(in thousands)			
Service cost	$ 1,052	$ 848	$ 1,900	$ 1,696
Interest cost	312	280	592	560
Expected return on plan assets	(281)	(159)	(440)	(318)
Amortization of net actuarial loss	111	91	202	182
Net periodic benefit cost	$ 1,194	$ 1,060	$ 2,254	$ 2,120

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 or the market-related value of assets are amortized over the average remaining service period of active participants.

Contributions

The Company is currently required to contribute $6.3 million to its Qualified Pension Plan. The Company has made $3.6 million in 2011 contributions as of June 30, 2011.

Note 10 - Derivative Financial Instruments

To mitigate a portion of the exposure to potentially adverse market changes in oil, natural gas, and NGL prices and the associated impact on cash flows, the Company has entered into various derivative commodity contracts. The Company s derivative contracts in place include swap and collar arrangements for oil, natural gas, and NGLs. As of June 30, 2011, and through the filing date of this report, the Company has commodity derivative contracts in place through the first quarter of 2014 for a total of approximately 8 MMBbls of anticipated crude oil production, 45 million MMBtu of anticipated natural gas production, and 1 MMBbls of anticipated NGL production.

The Company s oil, natural gas, and NGL derivatives are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities. The Company derives internal valuation estimates taking into consideration the counterparties credit ratings, the Company s credit rating, and the time value of money. These valuations are then compared to the respective counterparties mark-to-market statements. The pertinent 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, natural gas, and NGL derivative markets are highly active. The fair value of oil, natural gas, and NGL commodity derivative contracts was a net liability of $68.7 million and $52.3 million at June 30, 2011, and December 31, 2010, respectively.

Discontinuance of Cash Flow Hedge Accounting

Prior to January 1, 2011, the Company designated its commodity derivative contracts as cash flow hedges, whose 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 recognizes all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in AOCIL.

At December 31, 2010, accumulated other comprehensive loss (AOCL) included $18.6 million ($11.8 million, net of income tax) of unrealized losses, representing the change in fair value of the Company s open commodity derivative contracts designated as cash flow hedges as of that balance sheet date, less any ineffectiveness recognized. As a result of discontinuing hedge accounting on January 1, 2011, such fair values at December 31, 2010 were frozen in AOCL as of the de-designation date and reclassified into earnings as the original derivative transactions settle. During the six months ended June 30, 2011, $7.7 million ($4.9 million, net of income tax) of derivative losses relating to de-designated commodity hedges were reclassified from AOCL into earnings. As of June 30, 2011, AOCL included $10.9 million ($6.9 million, net of income tax) of unrealized losses on commodity

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derivative contracts that had been previously designated as cash flow hedges. The Company expects to reclassify into earnings from AOCL after-tax net losses of $6.9 million related to de-designated commodity derivative contracts during the next twelve months.

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

	As of June 30, 2011					
	Derivative Assets			Derivative Liabilities		
	Balance Sheet Classification		Fair Value	Balance Sheet Classification		Fair Value
			(in thousands)			
Commodity Contracts	Current Assets	$	28,985	Current Liabilities	$	(70,100)
Commodity Contracts	Noncurrent Assets		10,624	Noncurrent Liabilities		(38,233)
Derivatives not designated as hedging instruments		$	39,609		$	(108,333)

	As of December 31, 2010					
	Derivative Assets			Derivative Liabilities		
	Balance Sheet Classification		Fair Value	Balance Sheet Classification		Fair Value
			(in thousands)			
Commodity Contracts	Current Assets	$	43,491	Current Liabilities	$	(82,044)
Commodity Contracts	Noncurrent Assets		18,841	Noncurrent Liabilities		(32,557)
Derivatives designated as hedging instruments		$	62,332		$	(114,601)

The following table summarizes the unrealized and realized gain and loss from derivative cash settlements and changes in fair value of derivative contracts as presented in the accompanying statements of operations.

		For the Three Months Ended June 30, 2011		For the Six Months Ended June 30, 2011
		(in thousands)		
Cash settlement (gain) and loss:				
Oil contracts	$	10,633	$	17,363
Natural gas contracts		(590)		(2,317)
NGL contracts		3,933		5,347
Total cash settlement loss	$	13,976	$	20,393
Unrealized (gain) loss on changes in fair value:				
Oil contracts	$	(51,216)	$	16,151
Natural gas contracts		(6,681)		(2,421)
NGL contracts		45		10,430
Total net unrealized (gain) loss on change in fair value	$	(57,852)	$	24,160
Total unrealized and realized derivative (gain) loss	$	(43,876)	$	44,553

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

	Derivatives	Location on Consolidated Statement of Operations	For the Three Months Ended June 30, 2011	2010	For the Six Months Ended June 30, 2011	2010
			(in thousands)			
Amount of (gain) loss reclassified from AOCIL to realized hedge gain (loss)	Commodity Contracts	Realized hedge gain (loss)	$ 3,951	$ 1,163	$ 4,878	$ (782)

The realized net hedge loss for the three-month and six-month periods ended June 30, 2011, is comprised of realized cash settlements on commodity derivative contracts that were previously designated as cash flow hedges, whereas the realized net hedge gain (loss) for the three-month and six-month periods ended June 30, 2010, is comprised of realized cash settlements on all commodity derivative contracts. Realized hedge gains or losses from the settlement of oil, natural gas, and NGL derivatives previously designated as cash flow hedges are reported in the total operating revenues and other income section of the accompanying statements of operations. The Company realized a net hedge loss of $6.3 million and a net hedge gain of $9.3 million from its oil, natural gas, and NGL derivative contracts for the three months ended June 30, 2011, and 2010, respectively, and a net loss of $7.7 million and a net gain of $11.9 million from its oil, natural gas, and NGL derivative contracts for the six months ended June 30, 2011, and 2010, respectively.

As noted above, effective 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, and as such no new gains or losses are deferred in AOCIL at June 30, 2011. The following table details the effect of derivative instruments on AOCIL and the balance sheets (net of income tax):

	Derivatives	Location on Consolidated Balance Sheets	For the Six Months Ended June 30, 2010	For the Year Ended December 31, 2010
			(in thousands)	
Amount of gain on derivatives recognized in AOCIL during the period (effective portion)	Commodity Contracts	AOCIL	$ 53,765	$ 16,811

The Company has no derivatives designated as cash flow hedges at June 30, 2011. The following table details the ineffective portion of derivative instruments classified as cash flow hedges on the accompanying statements of operations for the three-month and six-month periods ended June 30, 2010.

Derivatives Qualifying as Cash Flow Hedges	Location on Consolidated Statements of Operations	Gain Recognized in Earnings (Ineffective Portion) For the Three Months Ended June 30, 2010	For the Six Months Ended June 30, 2010
		(in thousands)	

Commodity contracts	Unrealized and realized derivative (gain) loss	$	(2,087)	$	(9,822)

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Credit Related Contingent Features

As of June 30, 2011, and through the filing date of this report, all of the Company s derivative counterparties were members of the Company s credit facility bank syndicate. The Company s credit facility is secured by liens on substantially all of the Company s proved oil and gas assets; therefore such counterparties do not currently require the Company to post collateral in instances where the Company is in a liability position under its derivative instruments. No collateral was posted as of June 30, 2011, or through the filing date of this report.

Convertible Note Derivative Instruments

The contingent interest provision of the 3.50% Senior Convertible Notes is an embedded derivative instrument. As of June 30, 2011, and December 31, 2010, the fair value of this derivative was determined to be immaterial.

Note 11 - Fair Value Measurements

The Company follows fair value measurement authoritative guidance for all assets and liabilities measured at fair value. That 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 and 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 June 30, 2011:

	Level 1	Level 2 (in thousands)	Level 3
Assets:			
Derivatives	$	$ 39,609	$
Liabilities:			
Derivatives	$	$ 108,333	$
Net Profits Plan	$	$	$ 133,419

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 December 31, 2010:

	Level 1	Level 2 (in thousands)	Level 3
Assets:			
Derivatives	$	$ 62,332	$
Liabilities:			
Derivatives	$	$ 114,601	$
Net Profits Plan	$	$	$ 135,850

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 nonfinancial assets or liabilities measured at fair value on a nonrecurring basis at June 30, 2011, or December 31, 2010.

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Derivatives

The Company uses Level 2 inputs to measure the fair value of oil, natural gas, and NGL commodity derivatives. Fair values are based upon interpolated data. The Company derives internal valuation estimates taking into consideration the counterparties   credit ratings, the Company   s credit rating, and the time value of money. These valuations are then compared to the respective counterparties   mark-to-market statements. The considered factors result in an estimated exit-price that management believes provides a reasonable and consistent methodology for valuing derivative instruments.

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 SM Energy   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.

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 and gas 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 vice versa.

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, and the discount rates used in the calculations. The Company continually evaluates the assumptions used in this calculation in order to consider the current market environment for oil and gas prices, costs, discount rates, and overall market conditions. 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, natural gas, and NGL commodity markets.

If the commodity prices used in the calculation changed by five percent, the liability recorded at June 30, 2011, would differ by approximately $10 million. A one percentage point increase in the discount rate would decrease the liability by approximately $6 million whereas a one percentage point decrease in the discount rate would increase the liability by approximately $7 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.

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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.

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 June 30, 2011	For the Three Months Ended June 30, 2010	For the Six Months Ended June 30, 2011	For the Six Months Ended June 30, 2010
	(in thousands)			
Beginning balance	$ 147,403	$ 143,019	$ 135,850	$ 170,291
Net increase (decrease) in liability (a)	(6,092)	1,318	18,193	(218)
Net settlements (a)(b)(c)	(7,892)	(7,917)	(20,624)	(33,653)
Transfers in (out) of Level 3				
Ending balance	$ 133,419	$ 136,420	$ 133,419	$ 136,420

(a) 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.

(b) Settlements represent cash payments made or accrued under the Net Profits Plan. Settlements made under the Net Profits Plan of $2.0 million and $1.9 million for the three months ended June 30, 2011, and 2010, respectively, and $6.3 million and $20.1 million for the six months ended June 30, 2011, and 2010, respectively, resulted from divestiture proceeds.

(c) During the first quarter of 2011, the Company made the decision 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 or six-month periods ended June 30, 2011, related to these settlements.

3.50% Senior Convertible Notes

Based on the secondary market trading price of the 3.50% Senior Convertible Notes, the estimated fair value of the notes was approximately $406 million and $351 million as of June 30, 2011, and December 31, 2010, respectively. The fair value of the embedded contingent interest derivative on the 3.50% Senior Convertible Notes was zero as of June 30, 2011, and December 31, 2010.

6.625% Senior Notes

Based on the secondary market trading price of the 6.625% Senior Notes, the estimated fair value of the notes was approximately $357 million as of June 30, 2011.

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 exceeds the sum of the undiscounted cash flows. 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 a significant management estimate based on the best information available and estimated to be 12 percent for the six months ended June 30, 2011. Management believes that the discount rate is representative of current market conditions and reflects the following factors: estimate 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. Future operating costs are also adjusted as deemed appropriate for these estimates.

There were no proved oil and gas properties measured at fair value within the accompanying balance sheets at June 30, 2011, or December 31, 2010.

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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 inventory measured at fair value within the accompanying balance sheets at June 30, 2011, or December 31, 2010.

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 to the undiscounted expected abandonment cash flows. The credit-adjusted risk-free rate takes into account the Company s credit risk, the time value of money, and the current economic state. 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 June 30, 2011, or December 31, 2010.

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

Note 12 - Acquisition and Development Agreement

In June 2011, the Company entered into an Acquisition and Development Agreement (the Agreement) with Mitsui E&P Texas LP (Mitsui), an indirect subsidiary of Mitsui & Co., Ltd. Pursuant to the Agreement, the Company agreed to transfer to Mitsui a 12.5 percent working interest in certain oil and gas assets representing approximately 39,000 net acres in Dimmit, LaSalle, Maverick and Webb Counties, Texas. The transaction also provides for the conveyance of one-half of the Company s ownership in related gathering assets for reimbursement of 50 percent of costs incurred on those assets at the time of closing. The effective date of the transfer of the assets will be March 1, 2011. The transaction is expected to close in the third quarter of 2011, subject to the satisfaction of closing conditions, including the receipt of certain consents and the resolution of title and environmental defects exceeding specified levels. In return for the assets transferred, Mitsui has agreed to pay, or carry, 90 percent of certain drilling and completion costs on behalf of the Company and expenses for the affected acreage following the closing of the transaction until Mitsui has expended an aggregate $680.0 million on behalf of the Company, which is estimated to take three to four years based on the operator s announced drilling plans. Mitsui will also reimburse the Company for its share of capital expenditures and other costs, net of revenues, related to the period from March 1, 2011, until closing. The Company will apply these reimbursed costs to the remaining ten percent of the Company s drilling and completion costs for the affected acreage.

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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, exploitation, development, and production of crude oil, natural 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, and Woodford shale resource plays. We have built a portfolio of onshore properties in the contiguous United States with reserves, development drilling opportunities, and unconventional resource prospects, typically through the early entrance into existing and emerging resource plays. We believe this approach allows for stable and predictable production and reserves growth. Furthermore, by entering these plays early, we believe that we can capture larger resource potential at lower costs.

Our business strategy is to increase net asset value through attractive oil and gas investment activity, while maintaining a conservative capital structure and optimizing capital expenditures. We focus our efforts on the exploration for and development of onshore, lower-risk resource plays in North America. We believe our inventory of resource plays is well suited for growing reserves and production due to its predictable geology and lower-risk profile. Furthermore, our assets produce significant volumes of oil and NGLs that limit our exposure to the current lower natural gas price environment. Our strategy is based on the following:

- leveraging our core competencies in replicating resource play success in the drilling, completion, and development of oil, natural gas, and NGL reserves;
- focusing on resource plays with low-risk geology and high liquids content;
- exploiting our legacy assets and optimizing our asset base;
- selectively acquiring leasehold positions in new and emerging resource plays; and

- maintaining a strong balance sheet while funding the growth of our business.

In the second quarter of 2011 we had the following financial and operational results:

- Our average daily production for the three months ended June 30, 2011, was 20.4 MBbls of oil, 262.7 MMcf of gas, and 8.7 MBbls of NGLs, for a record average equivalent production rate of 436.9 MMCFE per day, compared with 276.4 MMCFE per day for the same period in 2010. Please see additional discussion below under the caption *Production Results*.

- We recorded net income for the three months ended June 30, 2011, of $124.5 million or $1.86 per diluted share compared to net income for the three months ended June 30, 2010, of $18.1 million or $0.28 per diluted share.

- Costs incurred for oil and gas producing activities for the three months ended June 30, 2011, were $352.2 million, compared with $189.3 million for the same period in 2010. Please see additional discussion below under the caption *Cost Incurred*.

Oil, Gas, and NGL Prices

Our financial condition and the results of our operations are significantly affected by the prices we receive for oil, natural gas, and NGL production, which can fluctuate dramatically. Please refer to ***Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2011, and 2010*** and ***Comparison of Financial Results and Trends Between the Six Months Ended June 30, 2011, and 2010*** for the realized price tables for the respective periods. Prior to 2011, we reported our natural gas production as a single stream of rich gas measured at the well head. As a result, we historically reported realized prices for our natural gas production for periods through December 31, 2010, that were higher than industry benchmarks due to the price uplift associated with incremental value contained in the higher BTU content of our gas production stream. Beginning in the first quarter of 2011, we changed our reporting for natural gas volumes to show natural gas and NGL production volumes consistent with title transfer for each product. Projected rapid production growth from our rich gas assets with plant product sales contracts necessitated a change in our production volume reporting. Prior period production volumes, revenues, and prices have not been reclassified to conform to the

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current presentation given the immateriality of the NGL volumes produced in prior periods. We sell the majority of our natural gas under contracts that use first-of-the-month index pricing, which means that 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 higher energy content contained in the gas stream. Our NGL production is generally sold using contracts that pay us the monthly average of the posted Oil Price Information Service Mont Belvieu daily settlement prices, adjusting for processing, transportation, and location differentials. Our crude oil and condensate are sold using contracts that pay us either the average of the NYMEX 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.

The following table is a summary of commodity price data for the second quarters of 2011 and 2010 and the first quarter of 2011:

	For the Three Months Ended					
	June 30, 2011		March 31, 2011		June 30, 2010	
Crude Oil (per Bbl):						
Average NYMEX price	$	102.28	$	94.46	$	77.88
Realized price	$	97.51	$	85.79	$	70.92
Natural Gas (per Mcf):						
Average NYMEX price	$	4.36	$	4.18	$	4.33
Realized price	$	4.63	$	4.35	$	4.54
Natural Gas Liquids (per Bbl):						
Average OPIS price	$	61.62	$	56.28	$	
Realized price	$	54.02	$	46.65	$	

Note: Prior year NGL production volumes, revenues, and prices have not been reclassified to conform to the current presentation given the immateriality of the volumes in prior periods. Please refer to additional discussion above.

We expect future prices for oil, gas, and NGLs to be volatile. In addition to supply and demand fundamentals, the relative strength of the U.S. dollar will likely continue to impact crude oil prices. Historically, NGL prices have trended and correlated with the price for crude oil. The supply of NGLs 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 increase supplies and negatively impact future pricing. Natural gas prices are facing downward pressure as a result of excess supply resulting from high levels of drilling activity across the country. The 12-month strip prices for NYMEX WTI crude oil, NYMEX Henry Hub natural gas, and OPIS NGLs as of June 30, 2011, were $98.03 per Bbl, $4.65 per MMBTU, and $57.86 per Bbl, respectively. Comparable prices as of July 26, 2011, were $101.65 per Bbl, $4.57 per MMBTU, and $ 61.12 per Bbl, respectively.

While changes in quoted NYMEX oil and natural gas and OPIS NGL prices are generally used as a basis for comparison within our industry, the price we receive is 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 Activities

We use financial derivative instruments as part of our financial risk management program. We have a Board-approved 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 the derivative contracts we have in place, 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 upward movements in oil, gas, and NGL prices while also setting a price floor for a portion of our production. Please see Note 10 Derivative Financial Instruments of Part I, Item 1 of this report for additional information regarding our oil, gas, and NGL derivatives, and see the caption, *Summary of Oil, Gas, and NGL Derivative Contracts in Place,* later in this section.

As of January 1, 2011, we elected to de-designate all commodity derivative contracts that had previously been designated as cash flow hedges as of December 31, 2010, and to discontinue hedge accounting prospectively. Accordingly, beginning January 1, 2011, all of our derivative contracts are stated at fair value each quarter with changes in fair value resulting in gains and losses, which are recognized immediately in earnings. For the three months ended June 30, 2011, realized cash settlements from our commodity risk management program for oil, natural gas, and NGLs were ($24.3) million, $9.1 million, and ($5.2) million,

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respectively. For the six months ended June 30, 2011, realized cash settlements from our commodity risk management program for oil, natural gas, and NGLs were ($43.4) million, $24.0 million, and ($8.7) million, respectively.

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 second quarters of 2011 and 2010 and the first quarter of 2011:

	For the Three Months Ended		
	June 30, 2011	**March 31, 2011**	**June 30, 2010**
Crude Oil (per Bbl):			
Realized price	$ 97.51	$ 85.79	$ 70.92
Less the effects of derivative cash settlements	(13.11)	(10.72)	(5.75)
Adjusted price, including the effects of derivative cash settlements	$ 84.40	$ 75.07	$ 65.17
Natural Gas (per Mcf):			
Realized price	$ 4.63	$ 4.35	$ 4.54
Plus the effects of derivative cash settlements	0.38	0.69	1.05
Adjusted price, including the effects of derivative cash settlements	$ 5.01	$ 5.04	$ 5.59
Natural Gas Liquids (per Bbl):			
Realized price	$ 54.02	$ 46.65	$
Less the effects of derivative cash settlements	(6.53)	(5.76)	
Adjusted price, including the effects of derivative cash settlements	$ 47.49	$ 40.89	$

Note: Prior year NGL production volumes, revenues, and prices have not been reclassified to conform to the current presentation given the immateriality of the volumes in prior periods. Please refer to additional discussion above under the caption *Oil, Gas, and NGL Prices*.

In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act was enacted into law. This financial reform legislation includes provisions that require over-the-counter derivative transactions to be executed through an exchange or centrally cleared. The Dodd-Frank Act requires the Commodities Futures Trading Commission (the CFTC), the SEC, and other regulators to establish rules and regulations to implement the new legislation. 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 of the proposed new rules and any additional regulations on our business 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.

Second Quarter 2011 Highlights

Operational activities. We operated an average of 11 drilling rigs company-wide during the second quarter of 2011. The focus of our operated drilling activity this year has been on oil and NGL-rich gas programs and selected natural gas projects of potential strategic importance to us. We have also participated in higher levels of outside-operated activity in oil and NGL-rich gas plays.

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We had four drilling rigs running in our operated Eagle Ford shale program in South Texas at the end of the second quarter 2011, up from three at the end of the first quarter. We focused our drilling in areas with higher BTU gas content and higher condensate yields. We continue to test different ways to complete these wells with the objective of optimizing future development potential. During the second quarter, we entered into two separate transactions to divest or sell down portions of our Eagle Ford shale position in order to lock in returns and provide funds to further develop the program. The first transaction involved all of our operated acreage in LaSalle County, Texas, along with a small adjoining block of acreage in Dimmit County, Texas. This transaction closed on August 2, 2011, before certain adjustments, at which time we received $227.4 million in cash proceeds. As part of this transaction, we also assigned a small portion of our committed takeaway capacity to serve these assets. The second transaction involves an agreement for the transfer of a 12.5 percent working interest in our non-operated acreage in exchange for a 90 percent carry of our drilling and completion costs in the same acreage for an amount not to exceed $680.0 million. This agreement also provides for the divestiture of one-half of our interest in the gathering assets that service the non-operated program in exchange for reimbursement of 50 percent of our costs on those assets. This transaction is expected to close in the third quarter of 2011, subject to the satisfaction of closing conditions, including the receipt of certain consents and the resolution of title and environmental defects exceeding specified levels. After completing these two transactions, we will have approximately 150,000 operated net acres and 46,000 non-operated net acres in the Eagle Ford shale play. With respect to infrastructure, we entered into a transaction during the quarter to sell gathering assets in the Eagle Ford shale play for $25.4 million and concurrently entered into a gas gathering agreement where we dedicated all production from certain portions of our operated Eagle Ford assets to be gathered, compressed, and treated by the same counterparty on a fee basis. During the quarter, we also entered into firm transportation agreements that will increase our pipeline capacity to approximately 460 MMCF per day of gross wet gas by the second half of 2014. Please refer to Note 7 - Commitments and Contingencies in Part I, Item 1 of this report for additional discussion concerning these agreements. On our outside-operated Eagle Ford acreage, the operator continued to increase activity throughout the first half of 2011. During the second quarter, our partner operated ten drilling rigs and it is our belief the activity will increase to 12 rigs by the end of 2011.

We operated two drilling rigs in the Williston Basin throughout the second quarter of 2011, both of which focused on Bakken and Three Forks drilling in our Raven and Gooseneck prospects in North Dakota. Our drilling results in these prospects have continued to meet or exceed our expectations throughout the first half of 2011. Consistent with other operators in the area, flooding and other weather-related issues limited our access to certain assets during the quarter. While drilling and completion activity was disrupted to some extent, our production operations were not significantly impacted. Elsewhere in the Rocky Mountain region, we continued to test the Niobrara formation in southern Wyoming with one drilling rig. We drilled an additional three test wells in southeastern Wyoming in the first half of 2011 in the South Silo field where we have approximately 26,000 net acres. In addition, we have been adding acreage with Niobrara potential in the Powder River Basin and we now have 63,000 acres in the basin.

In our operated horizontal Haynesville shale program in our ArkLaTex region, we operated two rigs in San Augustine County, Texas during the second quarter of 2011. Our leasehold acreage of approximately 33,000 net acres is prospective for both the Haynesville shale and the Bossier shale, and recent Haynesville well results continue to be highly encouraging. Our focus will be on holding this acreage through production to ensure we are in a position to benefit from any natural gas price increase in the future.

In our Mid-Continent region, we operated one to two rigs in our operated Granite Wash program in the Texas Panhandle and western Oklahoma during the second quarter of 2011 to test and delineate our acreage in the play. We have approximately 34,000 net acres in the Granite Wash, which are held by production.

Our Permian region operated a one rig program during the second quarter of 2011, splitting its focus on the testing of Wolfberry down spacing and drilling Mississippian targets as part of our exploration effort.

Production Results. The table below provides the regional breakdown of our second quarter 2011 production:

	Mid-Continent	ArkLaTex	South Texas & Gulf Coast	Permian	Rocky Mountain	Total (1)
Second Quarter 2011 Production:						
Oil (MBbl)	109.6	17.8	605.7	320.6	799.1	1,852.8
Gas (MMcf)	7,682.7	7,745.0	6,668.8	924.1	885.5	23,906.1
NGLs (MBbl)	17.3	18.9	741.5	4.3	7.7	789.6
Equivalent (MMCFE)	8,444.1	7,964.9	14,752.0	2,873.4	5,726.1	39,760.4
Avg. Daily Equivalents (MMCFE)	92.8	87.5	162.1	31.6	62.9	436.9
Relative percentage	21%	20%	37%	7%	15%	100%

(1) Totals may not add due to rounding.

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For the second quarter of 2011, our production was led by our South Texas & Gulf Coast region due to the ongoing drilling activities in our Eagle Ford shale program. Please refer to ***Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2011, and 2010****,* for additional discussion on production.

Costs Incurred. The following table sets forth the costs incurred for our oil and gas activities for the second quarter of 2011.

		For the Three Months Ended June 30, 2011 (in thousands)
Development costs	$	263,937
Facility costs		28,927
Exploration costs		50,198
Acquisitions of unproved properties		9,098
Total, including asset retirement obligations	$	352,160

Our capital and exploration activities reflect higher cash flows provided by operating activities, divestiture proceeds, and proceeds from the issuance of our 6.625% Senior Notes.

Credit Facility. We executed a $2.5 billion Fourth Amended and Restated Credit Agreement on May 27, 2011. The initial borrowing base for the facility has been set at $1.3 billion and the initial commitment amount is $1.0 billion. Please refer to **Overview of Liquidity and Capital Resources** below for additional discussion.

Acquisition and Development Agreement. In June 2011, we entered into an Acquisition and Development Agreement for the transfer of a 12.5 percent working interest in certain oil and gas assets, representing approximately 39,000 net acres, in Dimmit, LaSalle, Maverick and Webb Counties, Texas. The agreement also provides for the conveyance of one-half of our ownership in certain related gathering assets for reimbursement of 50 percent of costs incurred on those assets. The transaction is expected to close in the third quarter of 2011, subject to the satisfaction of closing conditions, including the receipt of certain consents and the resolution of title and environmental defects exceeding specified levels. Under the terms of the agreement, the counterparty has agreed to pay, or carry, 90 percent of our drilling and completion costs on the subject acreage following the closing of the transaction until the counterparty has expended an aggregate $680.0 million on our behalf, which is estimated to take three to four years. The counterparty will also reimburse us for its share of capital expenditures and other costs, net of revenues, related to the period from March 1, 2011, until closing. We will apply these reimbursed costs to the remaining ten percent of our drilling and completion costs for the affected acreage.

Mid-Continent Divestiture. In June 2011, we completed the divestiture of certain non-strategic Constitution Field assets located in our Mid-Continent region that were classified as assets held for sale at March 31, 2011.   Total cash received, before marketing costs and Net Profits Plan payments, was $35.7 million. The final sale price is subject to post-closing adjustments and is expected to be finalized during the second half of 2011. The estimated gain on this divestiture was approximately $28.5 million, and may be impacted by the post-closing adjustments mentioned above.

Eagle Ford Divestiture. During the quarter we entered into an agreement to divest certain operated Eagle Ford shale assets located in our South Texas & Gulf Coast region. This position is comprised of our entire operated acreage in LaSalle County, Texas, as well as an immaterial adjacent block of our operated acreage in Dimmit County, Texas. These assets were classified as assets held for sale at June 30, 2011. Subsequent to quarter end, we closed this transaction. Total cash received, before marketing costs, was $227.4 million. The final sales price is subject to post-closing adjustments and is expected to be finalized in the fourth quarter of 2011. The estimated gain on this divestiture is approximately $196.1 million, and may be impacted by the post-closing adjustments mentioned above.

Marcellus Divestiture. Subsequent to June 30, 2011, we entered into an agreement to divest all of our Marcellus shale assets located in Pennsylvania that were classified as assets held for sale at June 30, 2011, for $80.0 million in cash, subject to normal closing and post-closing adjustments. The agreement has an effective date of April 1, 2011, and is anticipated to close in the third quarter of 2011. The closing of this transaction is subject to the satisfaction of certain closing conditions, including the resolution of title and environmental defects exceeding specified levels.

Equity Compensation. Subsequent to June 30, 2011, we granted 234,308 PSUs and 78,165 RSUs pursuant to our long term incentive program. Please refer to Note 8 - Compensation Plans within Part I, Item 1 of this report for additional discussion.

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First Six Months 2011 Highlights

Production Results. The table below provides the regional breakdown of our first half of 2011 production.

	Mid-Continent	ArkLaTex	South Texas & Gulf Coast	Permian	Rocky Mountain	Total (1)
First Six Months of 2011 Production:						
Oil (MBbl)	160.5	33.3	1,114.9	676.0	1,652.6	3,637.3
Gas (MMcf)	15,049.0	13,326.3	13,403.5	1,838.1	2,023.8	45,640.7
NGLs (MBbl)	20.2	39.1	1,324.6	5.6	14.4	1,403.8
Equivalent (MMCFE)	16,133.1	13,760.9	28,040.4	5,927.3	12,025.8	75,887.5
Avg. Daily Equivalents (MMCFE)	89.1	76.0	154.9	32.7	66.4	419.3
Relative percentage	21%	18%	37%	8%	16%	100%

(1) Totals may not add due to rounding.

For the first half of 2011, our production was led by our South Texas & Gulf Coast region due to the ongoing drilling activities in our Eagle Ford shale program. Please refer to ***Comparison of Financial Results and Trends Between the Six Months Ended June 30, 2011, and 2010****,* for additional discussion on production.

Costs Incurred. The following table sets forth the costs incurred for our oil and gas activities for the first half of 2011.

	For the Six Months Ended June 30, 2011 (in thousands)
Development costs	$ 468,632
Facility costs	52,605
Exploration costs	101,564
Acquisitions of unproved properties	20,077
Total, including asset retirement obligations	$ 642,878

Our capital and exploration activities reflect higher cash flows provided by operating activities, divestiture proceeds, and proceeds from the issuance of our 6.625% Senior Notes.

6.625% Senior Notes. In the first quarter of 2011, we issued $350.0 million in aggregate principal amount of 6.625% Senior Notes. The notes were issued at par value and have a maturity date of February 15, 2019. Net proceeds from the issued notes were approximately $341.4 million. We used a portion of the proceeds from our notes offering to repay all of our outstanding balance under our credit facility. Remaining proceeds will be used to fund our ongoing capital expenditure program and for general corporate purposes.

Rocky Mountain Divestiture. In January 2011, we received cash, before marketing costs and Net Profits Plan payments, of $45.5 million from the completed sale of certain non-strategic assets located in our Rocky Mountain region that were classified as assets held for sale at December 31, 2010. The final gain on this divestiture was approximately $27.2 million.

Outlook for the Remainder of 2011 and 2012

We began 2011 operating two rigs on our Eagle Ford acreage with plans to increase our operated rig count to five or six drilling rigs by year end. We believe we have secured the drilling rigs and completion services necessary to execute our development program for the next few years. We have also purchased water rights in the Rio Grande River that we believe will meet our planned drilling and completion schedule. Currently we are running four operated rigs on our Eagle Ford acreage, one of which is capable of pad drilling. During 2010 and 2011, we entered into separate arrangements to increase the gas takeaway capacity from our operated Eagle Ford assets throughout 2011 and beyond. Throughout the first half of 2011, our operated Eagle Ford production has been constrained due to third-party system limitations, which are expected to be resolved in the second half of 2011. Our current contracted gross wet gas takeaway capacity is approximately 150 MMcf per day, which we anticipate to increase to over 200 MMcf per day by year end 2011. As pipeline issues are resolved and additional capacity from a different provider comes on-line, we anticipate we will be producing at or close to our committed capacity by year end. Beyond 2011, we have contracts in place for gas takeaway that ramp up over the next several years and eventually reach approximately 460 MMcf per day by the second half of 2014. For the remainder

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of 2011, we plan to continue to develop our Eagle Ford shale acreage focusing on high BTU content areas and begin down-spacing pilots to determine the optimal spacing for this play. In our non-operated Eagle Ford shale program, the operator is currently operating ten drilling rigs and our expectation is that they will increase to twelve rigs by the end of 2011.

We expect to add a third drilling rig in the third quarter of 2011 in our Bakken/Three Forks program in the Williston Basin. We have approximately 200,000 net acres in the Williston Basin, of which approximately 85,000 are in areas we are actively exploiting. Our drilling has been focused in Divide and McKenzie Counties in North Dakota. Our plans are to continue with a three to four rig program for the next several years. As conditions impacted by the second quarter flooding improve, we believe we will be able to continue our development pace without deviating significantly from our plan at the beginning of the year. Elsewhere in the Rocky Mountain region, we have plans to complete two Niobrara shale wells that were drilled in the first half of the year. We are working to secure a rig to test the Powder River Basin portion of our acreage later this year.

Due to strong results in our operated horizontal Haynesville shale program in our ArkLaTex region, we are no longer seeking to sell or joint venture our operated position in East Texas. We plan to continue drilling in this program with one operated rig until our acreage is held by production, which is anticipated to occur in the third quarter of 2012.

We plan to run two operated drilling rigs targeting the Granite Wash in our Mid-Continent region for the remainder of the year. Our acreage in this play is held by production and as a result we can adjust our activity levels quickly in this play. In the Permian Basin, we plan to split one drilling rig between the drilling of Wolfberry 20-acre wells and the testing of the Mississippian and Wolfcamp shale formations. Subsequent to June 30, 2011, we entered into an agreement to divest our Marcellus shale assets located in north-central Pennsylvania. Please refer to *Marcellus Divestiture* above for additional discussion.

We now expect our capital expenditure budget for 2011 to be approximately $1.6 billion, up from our previous budget of $1.1 billion. Changes in our Eagle Ford shale and Haynesville shale programs are responsible for the majority of the increase. The size and timing of our Eagle Ford transactions differ from the assumptions that we communicated earlier in the year. We are now transferring a smaller portion of our total position and closings for the two transactions are scheduled for later in the year which, taken together, will result in us recognizing additional capital costs and production. In the Haynesville, our prior capital budget assumed that we would enter into a transaction that would result in us not recognizing any further costs in the play after midyear. We believe our drilling results justify our continued development of the Haynesville for the remainder of 2011.

With the growth and improvement of our project inventory, we now have greater ability to forecast our activity level farther into the future. We expect a preliminary 2012 capital budget range of $1.4 to $1.5 billion. The activity will be primarily focused on continued development of our operated Eagle Ford shale and Bakken/Three Forks programs.

Please refer to **Overview of Liquidity and Capital Resources** for additional discussion regarding how we anticipate funding our 2011 and 2012 capital programs.

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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 June 30, 2011, and the immediately preceding three quarters. Additional details of per MCFE costs are presented later in this section.

	For the Three Months Ended			
	June 30, 2011	March 31, 2011	December 31, 2010	September 30, 2010
	($ in millions, except production data)			
Production (BCFE)	39.8	36.1	31.6	27.5
Oil, gas, and NGL production revenue	$ 333.9	$ 276.3	$ 250.1	$ 197.4
Realized hedge gain (loss)	$ (6.3)	$ (1.4)	$ 2.8	$ 8.8
Gain on divestiture activity	$ 30.0	$ 24.9	$ 23.1	$ 4.2
Lease operating expense	$ 33.2	$ 33.1	$ 33.5	$ 29.0
Transportation costs	$ 16.9	$ 15.0	$ 7.1	$ 4.9
Production taxes	$ 3.3	$ 17.8	$ 16.4	$ 10.7
DD&A	$ 115.4	$ 105.4	$ 94.7	$ 83.8
Exploration	$ 9.6	$ 12.7	$ 21.1	$ 14.4
General and administrative	$ 27.3	$ 25.9	$ 31.6	$ 26.2
Change in Net Profits Plan liability	$ (14.0)	$ 14.2	$ (4.6)	$ 4.1
Unrealized and realized derivative (gain) loss	$ (43.9)	$ 88.4	$ 13.0	$ 5.7
Net income (loss)	$ 124.5	$ (18.5)	$ 37.0	$ 15.5

Note: Historically, we have reported our natural gas production as a single stream of rich gas measured at the well head. Beginning in the first quarter of 2011, we changed our reporting for natural gas volumes to show natural gas and NGL production volumes consistent with title transfer for each product. Please refer to additional discussion above under the caption *Oil, Gas, and NGL Prices*.

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

	For the Three Months Ended June 30, 2011	For the Three Months Ended June 30, 2010	Amount Change Between Periods	Percent Change Between Periods	For the Six Months Ended June 30, 2011	For the Six Months Ended June 30, 2010	Amount Change Between Periods	Percent Change Between Periods
Net production volumes								
Oil (MMBbl)	1.9	1.4	0.5	31%	3.6	2.9	0.7	24%
Natural gas (Bcf)	23.9	16.7	7.2	43%	45.6	33.2	12.4	37%
NGLs (MMBbl)	0.8		0.8	N/A	1.4		1.4	N/A
BCFE (6:1)	39.8	25.2	14.6	58%	75.9	50.9	25.0	49%
Average daily production								
Oil (MBbl per day)	20.4	15.5	4.9	31%	20.1	16.2	3.9	24%
Natural gas (MMcf per day)	262.7	183.3	79.4	43%	252.2	183.7	68.5	37%
NGLs (MBbl per day)	8.7		8.7	N/A	7.8		7.8	N/A
MMCFE per day (6:1)	436.9	276.4	160.5	58%	419.3	281.1	138.2	49%
Oil, gas, & NGL production revenue (in thousands)								
Oil production revenue	$ 180,654	$ 100,149	$ 80,505	80%	$ 333,745	$ 211,095	$ 122,650	58%
Gas production revenue	110,625	75,738	34,887	46%	205,193	177,679	27,514	15%
NGL production revenue	42,655		42,665	N/A	71,309		71,309	N/A
Total	$ 333,934	$ 175,887	$ 158,047	90%	$ 610,247	$ 388,774	$ 221,473	57%
Oil, gas, & NGL production expense (in thousands)								
Lease operating expense	$ 33,219	$ 28,955	$ 4,264	15%	$ 66,290	$ 58,984	$ 7,306	12%
Transportation costs	16,864	5,098	11,766	231%	31,848	9,192	22,656	246%
Production taxes	3,259	11,115	(7,856)	(71)%	21,016	25,332	(4,316)	(17)%
Total	$ 53,342	$ 45,168	$ 8,174	18%	$ 119,154	$ 93,508	$ 25,646	27%
Realized sales price								
Oil (per Bbl)	$ 97.51	$ 70.92	$ 26.59	37%	$ 91.76	$ 71.86	$ 19.90	28%
Natural gas (per Mcf)	$ 4.63	$ 4.54	$ 0.09	2%	$ 4.50	$ 5.34	$ (0.84)	(16)%
NGLs (per Bbl)	$ 54.02	$	$ 54.02	N/A	$ 50.80	$	$ 50.80	N/A
Per MCFE Data:								
Realized price	$ 8.40	$ 6.99	$ 1.41	20%	$ 8.04	$ 7.64	$ 0.40	5%
Lease operating expenses	(0.84)	(1.15)	0.31	(27)%	(0.87)	(1.16)	0.29	(25)%
Transportation costs	(0.42)	(0.20)	(0.22)	110%	(0.42)	(0.18)	(0.24)	133%
Production taxes	(0.08)	(0.44)	0.36	(82)%	(0.28)	(0.50)	0.22	(44)%
General and administrative	(0.69)	(1.01)	0.32	(32)%	(0.70)	(0.96)	0.26	(27)%
Operating profit, before the effects of derivative cash settlements	$ 6.37	$ 4.19	$ 2.18	52%	$ 5.77	$ 4.84	$ 0.93	19%
Derivative cash settlement	(0.51)	0.37	(0.88)	(238)%	(0.37)	0.24	(0.61)	(254)%
Operating profit, including the effects of derivative cash settlements	$ 5.86	$ 4.56	$ 1.30	29%	$ 5.40	$ 5.08	$ 0.32	6%

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	For the Three Months Ended June 30, 2011	For the Three Months Ended June 30, 2010	Amount Change Between Periods	Percent Change Between Periods	For the Six Months Ended June 30, 2011	For the Six Months Ended June 30, 2010	Amount Change Between Periods	Percent Change Between Periods
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$ 2.90	$ 3.17	$ (0.27)	(9)%	$ 2.91	$ 3.10	$ (0.19)	(6)%
Earnings per share information								
Basic net income per common share	$ 1.96	$ 0.29	$ 1.67	576%	$ 1.67	$ 2.29	$ (0.62)	(27)%
Diluted net income per common share	$ 1.86	$ 0.28	$ 1.58	564%	$ 1.59	$ 2.24	$ (0.65)	(29)%
Basic weighted-average shares outstanding	63,638	62,917	721	1%	63,543	62,855	688	1%
Diluted weighted-average shares outstanding	66,909	64,566	2,343	4%	66,695	64,493	2,202	3%

Note: Prior period NGL production volumes, revenues, and prices have not been reclassified to conform to the current presentation given the immateriality of the volumes in prior periods. Please refer to additional discussion above under the caption *Oil, Gas, and NGL Prices*.

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 six months of 2011 increased 49 percent compared with the same period in 2010, driven primarily by the development of our Eagle Ford shale program.

Changes in production volumes, oil, gas, and NGL production revenues, and costs reflect the cyclical and highly volatile nature of our industry. Our realized price on a per MCFE basis increased 20 percent and five percent, respectively, for the three months and six months ended June 30, 2011, compared to the same periods in 2010. The majority of the increase is due to a higher realized price received for oil. Please refer to discussion above under *Oil, Gas, and NGL Prices* for information regarding how we have changed our reporting for natural gas volumes to show post processing production volumes of natural gas and NGLs for assets where our sales contracts permit us to do so.

Our LOE on a per MCFE basis for the three months and six months ended June 30, 2011, decreased 27 percent and 25 percent, respectively, compared to the same periods in 2010. The divestiture of non-strategic properties within our Rocky Mountain region in early 2011 and Permian region in late 2010 with meaningfully higher per unit operating costs is a driver of the decline in LOE from 2010. In addition, our LOE declined on a per MCFE basis due to higher production volumes. We believe the current high level of industry activity has the potential to increase lease operating costs during the remainder of 2011.

Production taxes on a per MCFE basis for the three months and six months ended June 30, 2011, decreased 82 percent and 44 percent, respectively, compared to the same periods in 2010. We received notification in the second quarter that wells within our Eagle Ford and Haynesville shale plays qualified for severance tax incentive programs in Texas. As a result a sizable incentive tax rebate was recorded during the quarter. We expect that substantially all future operated wells to be drilled in these areas will qualify for enacted reduced tax rates. We generally expect production taxes to trend with oil, gas, and NGL revenues.

Transportation costs on a per MCFE basis for the three months and six months ended June 30, 2011, increased 110 percent and 133 percent, respectively, compared to the same periods in 2010. This is a result of increased production in our Eagle Ford shale program, which has higher per unit transportation costs. We anticipate transportation costs will increase over the remainder of the year on a per MCFE basis, as the Eagle Ford shale becomes a large portion of our production mix.

Our general and administrative expense on a per MCFE basis for the three months and six months ended June 30, 2011, decreased 32 percent and 27 percent, respectively, compared to the same periods in 2010. 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 operating profit, including the effects of derivative cash settlements, for the three months and six months ended June 30, 2011, increased 29 percent and six percent, respectively, compared to the same periods in 2010.

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Our depletion, depreciation, and amortization, including asset retirement obligation accretion expense, for the three months and six months ended June 30, 2011, decreased nine percent and six percent, respectively, compared to the same periods in 2010. The property balances between the periods presented stayed relatively constant while the reserve base increased causing the per unit DD&A rate to decrease. 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 June 30, 2011, and 2010*** and ***Comparison of Financial Results and Trends Between the Six Months Ended June 30, 2011, and 2010*** for additional discussion on oil, gas, and NGL production expense, DD&A, and general and administrative expense.

Both basic and diluted earnings per share are presented in the table above. We use the treasury stock method to account for the potential diluted earnings per share impact of unvested RSUs, contingent PSAs, in-the-money stock options, and our 3.50% Senior Convertible Notes. In-the-money stock options, unvested RSUs, and contingent PSAs were dilutive for the three-month and six-month periods ended June 30, 2011, and 2010. Basic and diluted weighted-average common shares outstanding used in our June 30, 2011, and 2010, earnings per share calculations reflect increases in outstanding shares related to stock option exercises and vested RSUs. We issued 310,412 and 148,902 shares of common stock during the six-month periods ended June 30, 2011, and 2010, respectively, as a result of stock option exercises. The number of RSUs that vested and settled during the first six months of 2011 and 2010 were 18,836 and 34,588, respectively. For the three months and six months ended June 30, 2011, our average stock price exceeded the conversion price of $54.42 making our 3.50% Senior Convertible Notes dilutive for our 2011 quarter-to-date and year-to-date diluted weighted-average common shares outstanding calculation. The 3.50% Senior Convertible Notes were not dilutive for the three-month and six-month periods ended June 30, 2010. Currently our stock price continues to trade above the $54.42 conversion price, therefore we expect our 3.50% Senior Convertible Notes to have a dilutive impact on our third quarter earnings per share calculation. Please refer to Note 6 - Earnings per Share in Part I, Item 1 of this report for additional discussion.

Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2011, and 2010

Oil, gas, and NGL production revenue. Average daily reported production increased 58 percent to 436.9 MMCFE for the quarter ended June 30, 2011, compared with 276.4 MMCFE for the quarter ended June 30, 2010. Please refer to the discussion above under *Oil, Gas, and NGL Prices* regarding how we have changed our reporting for natural gas and NGL volumes. The following table presents the regional changes in our production, oil, gas, and NGL revenues, and costs between the two quarters:

	Average Net Daily Production Added (Decreased) (MMCFE/d)	**Oil, Gas, & NGL Revenue Added (Decreased) (in millions)**	**Production Costs Increase (Decrease) (in millions)**
Mid-Continent	3.0	$ 12.7	$ 0.2
ArkLaTex	51.3	21.1	0.2
South Texas & Gulf Coast	115.5	95.4	5.3
Permian	(9.1)	(0.6)	(0.1)
Rocky Mountain	(0.2)	29.4	2.6
Total	160.5	$ 158.0	$ 8.2

The largest increase in production occurred in the South Texas & Gulf Coast region as a result of drilling activity in our Eagle Ford shale program. Activity in our Eagle Ford shale program continues to increase and we anticipate production from this region will continue to increase for the foreseeable future. We also saw an increase in our ArkLaTex region, as a result of strong production performance from wells drilled our Haynesville shale program in late 2010 and early 2011.

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The following table summarizes the average realized prices we received for the three months ended June 30, 2011, and 2010 before the effects of cash derivative settlements.

	For the Three Months Ended June 30,			
	2011		2010	
Realized oil price ($/Bbl)	$	97.51	$	70.92
Realized gas price ($/Mcf)	$	4.63	$	4.54
Realized NGL price ($/Bbl)	$	54.02	$	
Realized equivalent price ($/MCFE)	$	8.40	$	6.99

Note: Prior period NGL production volumes, revenues, and prices have not been reclassified to conform to the current presentation given the immateriality of the volumes in prior periods. Please refer to additional discussion above under the caption *Oil, Gas, and NGL Prices*.

A 20 percent increase in the realized equivalent price per MCFE, combined with a 58 percent increase in production volumes, resulted in a meaningful increase in revenue between the two periods. We expect our realized prices to trend with commodity prices.

Realized hedge gain (loss). We recorded a net realized hedge loss of $6.3 million for the three-month period ended June 30, 2011, compared with a $9.3 million gain for the same period in 2010. The realized net loss in 2011 is comprised of realized cash settlements on commodity derivative contracts that were previously recorded in AOCL, whereas the realized net gain in 2010 is comprised of realized cash settlements on all commodity derivative contracts. 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. We recorded a $30.0 million net gain on divestiture activity for the quarter ended June 30, 2011, relating mainly to the divestiture of certain Constitution Field oil and gas assets in our Mid-Continent region. We recorded a $7.0 million net gain on divestiture activity for the comparable period of 2010, due primarily to the divestiture of non-core oil and gas properties located in our South Texas & Gulf Coast region and sales of assets in our Permian and Rocky Mountain regions. We are currently marketing other oil and gas properties, and we will continue to evaluate properties for divestiture in the normal course of our business.

Marketed gas system revenue and expense. Marketed gas system revenue increased $2.4 million to $18.8 million for the quarter ended June 30, 2011, compared with $16.4 million for the same period of 2010. Concurrent with the increase in marketed gas system revenue, marketed gas system expense increased $700,000 to $16.5 million for the quarter ended June 30, 2011, compared with $15.8 million for the same period of 2010. The net margin stayed relatively consistent with historical performance. We expect that marketed gas system revenue and expense will continue to coincide with increases and decreases in production and our realized price for natural gas.

Oil, gas, and NGL production expense. Total production costs for the second quarter of 2011 increased 18 percent, to $53.3 million compared with $45.2 million for the same period of 2010. Total oil and gas production costs per MCFE decreased $0.45, or 25 percent, to $1.34 for the second quarter of 2011, compared with $1.79 for the same period in 2010. The per MCFE decrease is comprised of the following:

- A $0.28 decrease in recurring LOE on a per MCFE basis reflects the 2010 and early 2011 sales of non-core properties with higher per unit LOE costs. We expect the various resources required to service our industry will become more sought after and harder to secure as a result of an increase in activity. We expect to see upward pressure on LOE throughout the remainder of the year.

- A $0.36 per MCFE decrease in production taxes due to severance tax incentives within our South Texas & Gulf Coast and ArkLaTex regions. Please refer to our production tax discussion under the caption **A three-month and six-month overview of selected production and financial information, including trends** for additional information.

- A $0.03 overall decrease in workover LOE on a per MCFE basis relating primarily to a decrease in workover activity in our Rocky Mountain region.

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- A $0.22 increase in overall transportation costs on a per MCFE basis primarily as a result of increased production in our Eagle Ford shale. Please refer to our transportation cost discussion under the caption **A three-month and six-month overview of selected production and financial information, including trends** for additional information.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A increased $35.6 million, or 45 percent, to $115.4 million for the three-month period ended June 30, 2011, compared with $79.8 million for the same period in 2010. Please refer to our depletion, depreciation, amortization, and asset retirement obligation liability accretion comparison discussion under the caption **A three-month and six-month overview of selected production and financial information, including trends** for additional information.

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

	For the Three Months Ended June 30,			
	2011		2010	
	(in millions)			
Geological and geophysical expenses	$		$	5.2
Exploratory dry hole expense				0.2
Overhead and other expenses		9.6		9.1
Total	$	9.6	$	14.5

Geological and geophysical expense decreased $5.2 million due to a decrease in the amount spent on seismic activity as our current plays become more established. We continue to test our current resource plays and expect to maintain a modest exploratory program for new assets in future periods. Any exploratory well incapable of producing oil, gas, or NGLs in commercial quantities will be deemed an exploratory dry hole, which will impact the amount of exploration expense we record.

General and administrative. General and administrative expense increased $1.9 million, or seven percent, to $27.3 million for the three months ended June 30, 2011, compared with $25.4 million for the same period of 2010. On a per unit basis, G&A expense decreased $0.32 to $0.69 per MCFE for the second quarter of 2011 compared to $1.01 per MCFE for the same period in 2010.

The majority of the increase in general and administrative expense is due to a $1.6 million increase in base compensation, accruals for cash bonuses, and equity compensation expense for the three months ended June 30, 2011, compared with the same period in 2010. The increase in accruals for cash bonuses is due to an increase in employee headcount between the two periods. We ramped up our hiring efforts for operational personnel during the second half of 2010.

Change in Net Profits Plan liability. For the quarter ended June 30, 2011, this non-cash item was a benefit of $14.0 million compared to a benefit of $6.6 million for the same period in 2010. This non-cash charge or benefit is directly related to the change in the estimated value of the associated liability over the reporting period. Commodity prices decreased from the first quarter of 2011 to the second quarter of 2011, resulting in a non-cash benefit. During the second quarter of 2010, we saw a reduction in the Net Profit Plan liability as a result of a decrease in expected future cash flows thereby reducing the future liability for amounts to be paid to participants. Adjustments to the liability are 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.

Unrealized and realized derivative (gain) loss. We recognized an unrealized and realized derivative gain of $43.9 million for the second quarter of 2011 compared to a gain of $2.1 million for the same period in 2010. The 2011 amount includes gains on unrealized changes in fair value on commodity derivative contracts of $57.9 million and realized cash settlement losses on derivatives for which unrealized changes in fair value were not previously recorded in other comprehensive loss of $14.0 million. The 2010 balance is comprised solely of the ineffective portion of derivatives designated as cash flow hedges. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional discussion.

Income tax expense. We recorded expense of $72.9 million for the second quarter of 2011 compared to expense of $12.4 million for the second quarter of 2010 resulting in effective tax rates of 36.9 percent and 40.8 percent, respectively. The change in income tax expense is primarily the result of the differences in components of net income discussed above and the second quarter 2011 effect of a change in the highest North Dakota marginal corporate tax rate. The 2011 decrease in effective tax rate from 2010 primarily reflects the changes in the mix of the highest marginal state tax rates, the state tax rate effect on year-to-date net income from divestiture and drilling activity in 2010, the cumulative effect related to the North Dakota tax rate change, and changes in the effects of other permanent differences. The current portion of our income tax expense is higher compared with the same period of

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2010 as a result of the differing impacts from 2011 and 2010 non-core asset divestitures and differing impacts of our annual drilling programs.

Comparison of Financial Results and Trends Between the Six Months Ended June 30, 2011, and 2010

Oil, gas, and NGL production revenue. Average daily reported production increased 49 percent to 419.3 MMCFE for the six months ended June 30, 2011, compared with 281.1 MMCFE for the same period in 2010. Please refer to the discussion above under *Oil, Gas, and NGL Prices* regarding how we have changed our reporting for natural gas and NGL volumes. The following table presents the regional changes in our production, oil, gas, and NGL revenues, and costs between the two periods:

	Average Net Daily Production Added (Decreased) (MMCFE/d)	Oil, Gas, & NGL Revenue Added (Decreased) (in millions)	Production Costs Increase (Decrease) (in millions)
Mid-Continent	(4.2)	$ (1.6)	$ (0.2)
ArkLaTex	40.0	26.7	1.0
South Texas & Gulf Coast	112.4	161.8	23.5
Permian	(7.7)	(2.6)	1.1
Rocky Mountain	(2.3)	37.2	0.2
Total	138.2	$ 221.5	$ 25.6

Please refer to ***Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2011, and 2010*** for additional discussion regarding the above results.

The following table summarizes the average realized prices we received for the six months ended June 30, 2011 and 2010 before the effects of cash derivative settlements.

	For the Six Months Ended June 30, 2011	2010
Realized oil price ($/Bbl)	$ 91.76	$ 71.86
Realized gas price ($/Mcf)	$ 4.50	$ 5.34
Realized NGL price ($/Bbl)	$ 50.80	$
Realized equivalent price ($/MCFE)	$ 8.04	$ 7.64

Note: Prior period NGL production volumes, revenues, and prices have not been reclassified to conform to the current presentation given the immateriality of the volumes in prior periods. Please refer to additional discussion above under the caption *Oil, Gas, and NGL Prices*.

A five percent increase in realized equivalent price per MCFE, combined with a 49 percent increase in production volumes, resulted in a meaningful increase in revenue. We expect our realized prices to trend with commodity prices.

Realized hedge gain (loss). We recorded a net realized hedge loss of $7.7 million for the six-month period ended June 30, 2011, compared with a $11.9 million gain for the same period in 2010. Please refer to ***Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2011, and 2010*** for additional discussion.

Gain on divestiture activity. We had a $54.9 million net gain on divestiture activity for the six months ended June 30, 2011, relating mainly to the divestiture of non-strategic oil and gas properties located in our Mid-Continent and Rocky Mountain regions. We recorded a $128.0 million net gain on divestiture activity for the comparable period of 2010, due primarily to the divestiture of non-strategic oil and gas properties located in our Rocky Mountain region that occurred in the first quarter of 2010.

Marketed gas system revenue and expense. Marketed gas system revenue decreased $3.7 million, or ten percent, to $34.5 million for the six months ended June 30, 2011, compared with $38.2 million for the comparable period of 2010. Concurrent with the decrease in marketed gas system revenue, marketed gas system expense decreased $5.4 million, or 14 percent, to $32.5 million for the six months ended June 30, 2011, compared with $37.9 million for the comparable period of 2010.

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Oil, gas, and NGL production expense. Total production costs for the first six months of 2011 increased 27 percent to $119.2 million compared with $93.5 million for the same period of 2010. Total oil and gas production costs per MCFE decreased $0.27 to $1.57 for the first six months of 2011, compared with $1.84 for the same period in 2010. The per MCFE decrease is comprised of the following:

- A $0.29 decrease in recurring LOE per MCFE.
- A $0.22 decrease in production taxes per MCFE.
- A $0.24 increase in overall transportation costs per MCFE.
- Overall workover LOE per MCFE remained relatively constant from period to period.

Please refer to ***Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2011, and 2010*** for additional discussion related to production expense.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A increased $63.2 million, or 40 percent, to $220.7 million for the six-month period ended June 30, 2011, compared with $157.5 million for the same period in 2010. Please refer to our depletion, depreciation, amortization, and asset retirement obligation liability accretion comparison discussion under the caption **A three-month and six-month overview of selected production and financial information, including trends** for additional information.

Abandonment and impairment of unproved properties. We recorded abandonment and impairment of unproved properties expense of $4.3 million for the six months ended June 30, 2011, associated with lease expirations in our ArkLaTex region. We recorded $3.3 million of abandonment and impairment of unproved properties expense for the comparable period in 2010, associated mainly with lease expirations in our Rocky Mountain and ArkLaTex regions. We generally expect abandonments and impairments of unproved properties to be more likely to occur in periods of low commodity prices, since fewer dollars will be available for exploratory and development efforts.

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

	For the Six Months Ended June 30,			
	2011		2010	
	(in millions)			
Geological and geophysical expenses	$	2.1	$	8.8
Exploratory dry hole expense				0.4

Overhead and other expenses		20.2		19.2
Total	$	22.3	$	28.4

Please refer to ***Comparison of Financial Results and Trends Between the Three Months Ended June 30, 2011, and 2010****,* in the above section for additional discussion.

General and administrative. General and administrative expense increased $4.3 million, or nine percent, to $53.2 million for the six months ended June 30, 2011, compared with $48.9 million for the same period of 2010. On a per unit basis, G&A expense decreased $0.26 to $0.70 per MCFE for the six months of 2011 compared to $0.96 per MCFE for the same six-month period in 2010.

General and administrative expense increased due to a $3.9 million increase in base compensation, accruals for cash bonuses, and equity compensation expense for the six months ended June 30, 2011, compared with the same period in 2010. The increase in accruals for cash bonuses is due to an increase in employee headcount between the two periods. We ramped up our hiring efforts for operational personnel during the second half of 2010. G&A expense decreased $1.7 million due to a decrease in Net Profits Plan payments as a result of the Permian divestiture that was completed in late 2010.

Change in Net Profits Plan liability. For the six months ended June 30, 2011, this non-cash item was an expense of $211,000 compared to a benefit of $33.9 million for the same period in 2010. This non-cash charge or benefit is directly related to the change in the estimated value of the associated liability between the reporting periods. The change between the two periods is due to increases in commodity prices, which we broadly expect the change in this liability to trend with. Adjustments

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to the liability are 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.

Unrealized and realized derivative (gain) loss. We recognized an unrealized and realized derivative loss of $44.6 million for the first six months of 2011 compared to a gain of $9.8 million for the same period in 2010. The 2011 amount includes losses on unrealized changes in fair value on commodity derivative contracts of $24.2 million and realized cash settlement losses on derivatives for which unrealized changes in fair value were not previously recorded in other comprehensive loss of $20.4 million. The 2010 balance is comprised solely of the ineffective portion of derivatives designated as cash flow hedges. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report.

Income tax expense. Income tax expense totaled $61.8 million for the six-month period ended June 30, 2011, compared to an income tax expense of $87.3 million for the same period in 2010, resulting in effective tax rates of 36.8 percent and 37.7 percent, respectively. The change in income tax expense is the result of the differences in components of net income. The 2011 decrease in effective tax rate from 2010 is primarily the result of the change in North Dakota s corporate tax rate and to a lesser extent the impact of other permanent differences including the domestic production activities deduction partially offset by an increase related to the mix of the highest marginal state tax rates resulting from divestiture and drilling activity in 2010. The current portion of our tax expense is greater in 2011 compared to 2010 due to the differing impact of our non-core asset divestitures in 2011.

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

For the remainder of 2011, we anticipate that cash flow from operations, the remaining proceeds from the issuance of our 6.625% Senior Notes, expected divestiture proceeds, and/or joint venture activity will fund the majority of our capital program. Our credit facility will be used to fund any remaining balance of our capital program. Although we anticipate that our cash flow and borrowing capacity under our credit facility will be more than sufficient to fund our current capital program, accessing the capital markets or using other financing alternatives is an option if deemed the best solution for our demands. We will continue to evaluate our property base to identify and divest of 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 the debt and equity markets. From time to time, we may be able to enter into carrying cost funding and sharing arrangements with third parties for particular exploration and development programs. All of our sources of liquidity can be impacted by the general condition of the broad economy and by significant fluctuations in oil, gas, and NGL 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 net realized revenues related to 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 due to lower commodity prices or any divestiture by us of a significant amount of producing properties. Historically, decreases in commodity prices have limited our industry s access to the capital markets. In the first quarter of 2011, we issued $350.0 million in aggregate principal amount of 6.625% Senior Notes at par. During the second quarter of 2011, we amended and restated our credit facility with a $2.5 billion maximum facility amount, $1.0 billion in current lender commitments, and a borrowing base of $1.3 billion. We also entered into an Acquisition and Development Agreement that will fund, or carry, 90 percent of our costs for the drilling and completion of wells in our outside operated Eagle Ford position until $680.0 million has been expended on our behalf. Subsequent to June 30, 2011, we divested of all of our operated acreage in LaSalle County, Texas and a small adjacent block of our operated acreage in Dimmitt County, Texas for $227.4 million, subject to post-closing adjustments.

Current Credit Facility

In May 2011, we entered into our Fourth Amended and Restated Credit agreement with a $2.5 billion senior secured revolving credit facility with a scheduled maturity date of May 27, 2016. The credit facility replaces our prior $1.0 billion senior secured revolving credit facility. The initial borrowing base for the credit facility is $1.3 billion and our lenders have agreed to a current aggregate commitment amount of $1.0 billion. The borrowing base is redetermined semi-annually by our lenders. We believe that the current commitment is sufficient to meet our current liquidity and operating needs. To date, we have experienced no issues drawing upon our credit facility. No individual bank participating in the credit facility represents more than 10 percent of the lending commitments under the credit facility.

We had no borrowings outstanding under our credit facility as of June 30, 2011. We had two letters of credit outstanding under our credit facility for a total amount of $608,000 as of June 30, 2011, which reduces the amount available under the credit facility on a dollar-for-dollar basis. We had $999.4 million available borrowing capacity under this facility as of June 30, 2011. Our daily weighted-average credit facility debt balance was zero for the three months ended June 30, 2011. Our daily weighted-average credit facility debt balance was $8.2 million for the six months ended June 30, 2011, and $1.4 million and $62.8 million for the three months and six months ended June 30, 2010, respectively.

Please refer to Note 5 Long-Term Debt in Part I, Item 1 of this report, for further discussion on our credit facility.

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 3.50% Senior Convertible Notes debt discount, and amortization of deferred financing costs. Our weighted-average interest rates for the three-month periods ended June 30, 2011, and 2010 were 10.6 percent and 9.4 percent, respectively, and 9.6 percent and 8.1 percent, respectively, for the six months ended June 30, 2011, and 2010. The increase in our weighted-average interest rate from 2010 is the result of higher commitment fees and non-cash charges being allocated over a much lower average outstanding credit facility debt balance.

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 earnings before interest, taxes, depreciation, depletion, amortization, and exploration expense of less than 4.0 to 1.0 and a current ratio, as defined by our credit agreement, of not less than 1.0. As of June 30, 2011, our debt to EBITDAX ratio and current ratio as defined by our credit agreement, were 0.86 and 3.19 respectively. 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 debt obligations, trade payables, income taxes, common stock repurchases, and stockholder dividends. Expenditures for exploration and development of oil and gas properties are the primary use of our capital resources. In the first six months of 2011, we spent $662.4 million for exploration and development capital expenditures. These amounts differ from our costs incurred amounts based on the timing of cash payments associated with these activities as compared to the accrual based activity upon which costs incurred amounts are presented. These cash outflows were funded using cash inflows from operations, proceeds from the sale of assets, and proceeds from our 6.625% Senior Notes.

The amount and allocation of future capital expenditures will depend upon a number of factors including the number and size of available economic acquisitions and drilling opportunities, our cash flows from operating, investing, and financing activities, and our ability to assimilate acquisitions and execute our drilling programs. In addition, the impact of oil, natural gas, and NGL prices on investment opportunities, the availability of capital and borrowing facilities, and the success of our 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 opportunities, debt requirements, and other factors.

As of the filing date of this report, we have Board authorization 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 indenture governing our 6.625% Senior Notes, compliance with securities laws, and the terms and provisions of our stock repurchase program. There have been no share repurchases to date in 2011, and we do not plan to repurchase shares for the remainder of 2011.

We have no debt maturities until April 1, 2012, when all or a portion of our outstanding 3.50% Senior Convertible Notes can be put to us. If the notes are put to us on that date, we have the option of paying the purchase price in cash, shares of our common stock, or a combination thereof. On or after April 6, 2012, we have the option of redeeming all or a portion of the outstanding notes for cash. The notes are convertible into shares of our common stock under certain circumstances, including if they are called for redemption, and we may elect to settle conversion obligations in cash, shares of our common stock, or a combination thereof. The closing price of our common stock was higher than the conversion trigger price of $70.75 per share for at least 20 trading days in the 30 consecutive trading days ending on the last trading day for the quarter ended March 31, 2011, and therefore the holders of the notes had the right to convert all or a portion of their notes during the quarter ended June 30, 2011. None of the holders opted to convert their notes during the second quarter. The closing price of our common stock did not exceed the conversion trigger price for the quarter ended June 30, 2011; therefore none of the notes can be converted during the third quarter of 2011.

Current proposals to fund the federal government budget include eliminating or reducing current tax deductions for intangible drilling costs, the domestic production activities deduction, 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 exploration and development capital programs and those of our peers in the industry. These funding reductions could have a significant adverse effect on drilling in the United States for a number of years.

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The following table presents changes in cash flows between the six-month periods ended June 30, 2011, and 2010. The analysis following the table should be read in conjunction with our condensed consolidated statements of cash flows in Part I, Item 1 of this report.

	For the Six Months Ended June 30, 2011	2010	Change	Percent Change
	(in thousands)			
Net cash provided by operating activities	$ 369,973	$ 270,150	$ 99,823	37%
Net cash used in investing activities	$ (566,775)	$ (82,716)	$ (484,059)	585%
Net cash provided by (used in) financing activities	$ 292,805	$ (187,834)	$ 480,639	(256)%

Analysis of Cash Flow Changes Between the Six Months Ended June 30, 2011, and June 30, 2010

Operating activities. Cash received from oil and gas production revenue, including the effects of derivative cash settlements, increased $159.0 million to $562.6 million for the first six months of 2011, compared with $403.6 million for the same period in 2010. Cash paid for lease operating expenses increased $5.3 million to $69.0 million for the first six months of 2011, compared with $63.7 million for the same period in 2010.

Investing activities. Cash outflows for capital expenditures increased by $357.7 million for the six months ended June 30, 2011, compared with the same period in 2010. This increase in capital and exploration activities reflects higher cash flows available to us for investment provided by operating activities, divestiture proceeds, and proceeds from the issuance of our 6.625% Senior Notes. Net proceeds from the sale of oil and gas properties decreased $150.0 million between the two periods due to a decrease in the size of the divestiture packages.

Financing activities. We received net proceeds of $341.4 million from the issuance of our 6.625% Senior Notes in the first quarter of 2011. We incurred $8.5 million of debt issuance costs related to our amended credit facility in 2011. Net repayments on our credit facility decreased by $140.0 million for the six months ended June 30, 2011, compared with the same period in 2010. As of June 30, 2011, we had no outstanding borrowings under the credit facility.

Commodity Price Risk and Interest Rate Risk

We are exposed to market risk, including the effects of changes in oil, gas, and NGL commodity prices and changes in interest rates as discussed below under the caption *Summary of Interest Rate Risk.* 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 or our 6.625% Senior Notes, but do affect their fair market value.

There has been no material change to the natural gas and crude oil price sensitivity analysis previously disclosed. Refer to the corresponding section under Part II, Item 7 of our 2010 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 June 30, 2011, and as of the filing date of this report, we have derivative positions in place covering a portion of anticipated production through the first quarter of 2014 totaling approximately 8 MMBbls of oil, 45 million MMBtu of natural gas, and 1 MMBbls of NGLs.

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.

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The following tables describe the volumes, average contract prices, and fair values of contracts we have in place as of June 30, 2011.

Oil Contracts

Oil Swaps

Contract Period	NYMEX WTI Volumes (Bbls)	Weighted-Average Contract Price (per Bbl)	Fair Value at June 30, 2011 (Liability) (in thousands)
Third quarter 2011	327,800	$ 68.63	$ (9,005)
Fourth quarter 2011	325,400	$ 73.51	(7,822)
2012	1,514,200	$ 82.62	(26,087)
2013	294,600	$ 84.30	(4,791)
All oil swaps	2,462,000		$ (47,705)

Oil Collars

Contract Period	NYMEX WTI Volumes (Bbls)	Weighted-Average Floor Price (per Bbl)	Weighted-Average Ceiling Price (per Bbl)	Fair Value at June 30, 2011 (Liability) (in thousands)
Third quarter 2011	576,750	$ 63.81	$ 84.69	$ (10,101)
Fourth quarter 2011	514,850	$ 61.86	$ 81.73	(10,836)
2012	1,434,600	$ 76.49	$ 109.79	(5,281)
2013	2,146,500	$ 75.84	$ 109.81	(11,631)
2014	560,200	$ 80.00	$ 116.05	(1,251)
All oil collars	5,232,900			$ (39,100)

Natural Gas Contracts

Natural Gas Swaps

Contract Period	Volumes (MMBtu)	Weighted-Average Contract Price (per MMBtu)	Fair Value at June 30, 2011 Asset (in thousands)
Third quarter 2011	3,780,000	$ 6.06	$ 6,877
Fourth quarter 2011	4,730,000	$ 5.88	6,832

2012	16,500,000	$	5.56		14,875
2013	13,810,000	$	5.05		1,611
2014	2,910,000	$	5.42		398
All natural gas swaps*	41,730,000			$	30,593

*Natural gas swaps are comprised of IF ANR OK (2%), IF CIG (4%), IF El Paso Permian (4%), IF HSC (10%), IF NGPL MidCont. (3%), IF NNG Ventura (3%), IF PEPL (22%), IF Reliant N/S (32%), IF TETCO STX (18%), and NYMEX Henry Hub (2%).

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Natural Gas Collars

Contract Period	Volumes (MMBtu)	Weighted-Average Floor Price (per MMBtu)	Weighted-Average Ceiling Price (per MMBtu)	Fair Value at June 30, 2011 Asset (in thousands)
Third quarter 2011	1,660,000	$ 5.25	$ 6.49	$ 1,811
Fourth quarter 2011	1,660,000	$ 5.25	$ 6.49	1,622
All gas collars*	3,320,000			$ 3,433

*Natural gas collars are comprised of IF CIG (27%), IF HSC (7%), IF PEPL (64%), and NYMEX Henry Hub (2%).

Natural Gas Liquid Contracts

NGL Swaps

Contract Period	Volumes (approx. Bbls)	Weighted-Average Contract Price (per Bbl)	Fair Value at June 30, 2011 (Liability) (in thousands)
Third quarter 2011	312,000	$ 38.05	$ (4,513)
Fourth quarter 2011	285,000	$ 38.36	(3,948)
2012	725,000	$ 37.02	(6,749)
2013	84,000	$ 44.95	(735)
All NGL swaps*	1,406,000		$ (15,945)

*NGL swaps are comprised of OPIS Mont. Belvieu LDH Propane (25%), OPIS Mont. Belvieu Purity Ethane (51%), OPIS Mont. Belvieu NON-LDH Isobutane (4%), OPIS Mont. Belvieu NON-LDH Natural Gasoline (11%), and OPIS Mont. Belvieu NON-LDH Normal Butane (9%).

Refer to Note 10   Derivative Financial Instruments in Part I, Item 1 of this report for additional information regarding our oil, gas, and NGL derivative contracts.

Summary of Interest Rate Risk

Market risk is estimated as the potential change in fair value resulting from an immediate hypothetical one percentage point parallel shift in the yield curve. For fixed-rate debt, interest changes affect the fair market value but do not impact results of operations or cash flows. Conversely, interest rate changes for floating-rate debt generally do not affect the fair market value but do impact future results of operations and cash flows, assuming other factors are held constant. The carrying amount of our floating-rate debt typically approximates its fair value. As of June 30, 2011, we had no floating-rate debt outstanding, and our fixed-rate debt outstanding, net of debt discount, was $630.3 million.

Contractual Obligations

Please see Note 7 Commitments and Contingencies under Part I, Item 1 of this report for information pertaining to our new contractual obligations.

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 entities 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 June 30, 2011, we have not been involved in any unconsolidated SPE transactions.

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

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Critical Accounting Policies and Estimates

We refer you to the corresponding section in Part II, Item 7 of our 2010 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.

Environmental

SM Energy s compliance with applicable environmental laws and regulations has to date not resulted in significant capital expenditures or material adverse effects on our liquidity or results of operations. We believe we are in substantial compliance with environmental laws and regulations and do not currently anticipate that material future expenditures will be required under the existing regulatory framework. However, environmental laws and regulations are subject to frequent changes and we are unable to predict the impact that compliance with future laws or regulations, such as those currently being considered as discussed below, may have on future capital expenditures, liquidity, and results of operations.

Hydraulic fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas and NGLs, from tight formations. For additional information about hydraulic fracturing and related environmental matters, see Risk Factors Risks Related to Our Business *Proposed federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays* in our 2010 Form 10-K.

Climate Change. In December 2009, the U.S. Environmental Protection Agency (the EPA) determined that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth s atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the Clean Air Act (CAA). The EPA recently adopted two sets of rules regulating greenhouse gas emissions under the CAA, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, effective January 2, 2011. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including petroleum refineries, on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010, as well as certain onshore oil and natural gas production facilities, on an annual basis, beginning in 2012 for emissions occurring in 2011.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and many states have already taken measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

In terms of opportunities, the regulation of greenhouse gas emissions and the introduction of alternative incentives, such as enhanced oil recovery, carbon sequestration and low carbon fuel standards, could benefit us in a variety of ways. For example, although climate change legislation could reduce the overall demand for the oil and natural gas that we produce, the relative demand for natural gas may increase since the burning of natural gas produces lower levels of emissions than other readily available fossil fuels such as oil and coal. In addition, if renewable resources, such as wind or solar power become more prevalent, natural gas-fired electric plants may provide an alternative backup to maintain consistent electricity supply. Also, if states adopt low-carbon fuel standards, natural gas may become a more attractive transportation fuel. For the six-month periods ended June 30, 2011, and 2010,

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approximately 71 percent and 65 percent, respectively, of our production was natural gas and NGLs on an MCFE basis. Market-based incentives for the capture and storage of carbon dioxide in underground reservoirs, particularly in oil and natural gas reservoirs, could also benefit us through the potential to obtain greenhouse gas emission allowances or offsets from or government incentives for the sequestration of carbon dioxide.

Cautionary Information about Forward-Looking Statements

This Quarterly Report on 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 expressions are 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;*

- *future oil, natural gas, and NGL production estimates;*

- *our outlook on future oil, natural 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 2010 Annual Report on Form 10-K and include such factors as:

- *the volatility of oil, natural gas, and NGL prices, and the effect it may have on our profitability, financial condition, cash flows, access to capital, and ability to grow;*

- *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;*

- *the imprecise estimations of our actual quantities and present values of proved oil, natural gas, and NGL reserves;*

- *the uncertainty in evaluating recoverable reserves and other expected benefits or liabilities;*

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- *the possibility that exploration and development drilling may not result in commercially producible reserves;*

- *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 our reported anticipated divestiture, joint venture, farm-down, 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 price risk management activities may result in financial losses or may limit the prices that we receive for oil, natural gas, and NGL sales;*

- *the inability of one or more of our customers to meet their obligations;*

- *price declines or unsuccessful exploration efforts result in write-downs of our asset carrying values;*

- *the impact that lower oil, natural 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, natural gas, and NGLs;*

- *new technologies may cause our current exploration and drilling methods to become obsolete;*

- *the uncertainties regarding the ultimate impact of potentially dilutive securities; 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. 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*, *Summary of Oil, Gas, and NGL Derivative Contracts in Place*, and *Summary of Interest Rate Risk* in Item 2 above and is incorporated herein by reference.

ITEM 4. CONTROLS AND PROCEDURES

We maintain a system of disclosure controls and procedures that is designed to 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 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 timely decisions regarding required disclosures.

We carried out an evaluation, under the supervision and with the participation of our management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this Quarterly Report on Form 10-Q. Based upon that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that our disclosure controls and procedures are effective for the purposes discussed above as of the end of the period covered by this Quarterly Report on Form 10-Q. There was no change in our internal control over financial reporting that occurred during our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the effectiveness of our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

There have been no material changes from the legal proceedings as previously disclosed in our 2010 Form 10-K in response to Item 3 of Part I of such Form 10-K.

ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors as previously disclosed in our 2010 Form 10-K in response to Item 1A of Part I of such Form 10-K.

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ITEM 6. EXHIBITS

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

Exhibit	Description
2.1*+	Purchase and Sale Agreement dated June 9, 2011, among SM Energy Company, Statoil Texas Onshore Properties LLC, and Talisman Energy USA Inc.
2.2*+	Acquisition and Development Agreement dated June 29, 2011 between SM Energy Company and Mitsui E&P Texas LP
10.1*	Fourth Amended and Restated Credit Agreement dated May 27, 2011, among SM Energy Company, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto
10.2***	Gas Gathering Agreement dated May 31, 2011 between Regency Field Services LLC and SM Energy Company
10.3***	Gathering and Natural Gas Services Agreement effective as of April 1, 2011 between SM Energy Company and ETC Texas Pipeline, Ltd.
10.4***	Gas Processing Agreement effective as of April 1, 2011 between ETC Texas Pipeline, Ltd. and SM Energy Company
10.5*	Employee Stock Purchase Plan, As Amended and Restated as of June 10, 2011
10.6*	Form of Performance Stock Unit Award Agreement as of July 1, 2011
10.7*	Form of Restricted Stock Unit Award Agreement as of July 1, 2011
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.
***	Filed with this report. Certain portions of this exhibit have been redacted and are subject to a confidential treatment request filed with the Securities and Exchange Commission pursuant to Rule 24b-2 under the Securities Exchange Act of 1934.
****	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.
	Exhibit constitutes a management contract or compensatory plan or agreement.
+	Schedules and exhibits to this exhibit as listed in this exhibit have been omitted from this exhibit pursuant to the provisions of Item 601(b)(2) of Regulation S-K. The Company will furnish supplementally a copy of any such omitted schedule or exhibit to the Securities and Exchange Commission upon request.

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SIGNATURES

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

SM ENERGY COMPANY

August 2, 2011	By:	/s/ ANTHONY J. BEST Anthony J. Best President and Chief Executive Officer
August 2, 2011	By:	/s/ A. WADE PURSELL A. Wade Pursell Executive Vice President and Chief Financial Officer
August 2, 2011	By:	/s/ MARK T. SOLOMON Mark T. Solomon Vice President and Controller