SM Energy Co
Form 10-Q
August 03, 2010

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2010

Commission File Number 001-31539

SM ENERGY COMPANY

(Exact name of registrant as specified in its charter)

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

(303) 861-8140

(Registrant s telephone number, including area code)

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

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

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

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

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

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

As of July 28, 2010 the registrant had 63,007,624 shares of common stock, $0.01 par value, outstanding.

SM ENERGY COMPANY

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

SM ENERGY COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(In thousands, except share amounts)

	June 30, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 10,249	$ 10,649
Accounts receivable	108,427	116,136
Refundable income taxes	23,215	32,773
Prepaid expenses and other	14,284	14,259
Derivative asset	45,481	30,295
Deferred income taxes		4,934
Total current assets	201,656	209,046
Property and equipment (successful efforts method), at cost:		
Land	1,483	1,371
Proved oil and gas properties	3,066,300	2,797,341
Less - accumulated depletion, depreciation, and amortization	(1,203,841)	(1,053,518)
Unproved oil and gas properties, net of impairment allowance of $62,507 in 2010 and $66,570 in 2009	138,531	132,370
Wells in progress	97,312	65,771
Materials inventory, at lower of cost or market	31,305	24,467
Oil and gas properties held for sale less accumulated depletion, depreciation, and amortization	7,115	145,392
Other property and equipment, net of accumulated depreciation of $16,478 in 2010 and $14,550 in 2009	15,472	14,404
	2,153,677	2,127,598
Other noncurrent assets:		
Derivative asset	30,169	8,251
Restricted cash subject to Section 1031 Exchange	19,595	
Other noncurrent assets	12,288	16,041
Total other noncurrent assets	62,052	24,292
Total Assets	**$ 2,417,385**	**$ 2,360,936**
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 270,030	$ 236,242
Derivative liability	37,903	53,929
Deposit associated with oil and gas properties held for sale		6,500
Deferred income taxes	4,970	
Total current liabilities	312,903	296,671
Noncurrent liabilities:		

Long-term credit facility				188,000
Senior convertible notes, net of unamortized discount of $16,288 in 2010, and $20,598 in 2009		271,212		266,902
Asset retirement obligation		64,284		60,289
Asset retirement obligation associated with oil and gas properties held for sale		1,526		18,126
Net Profits Plan liability		136,420		170,291
Deferred income taxes		408,997		308,189
Derivative liability		24,046		65,499
Other noncurrent liabilities		15,164		13,399
Total noncurrent liabilities		921,649		1,090,695
Commitments and contingencies				
Stockholders equity:				
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued: 63,110,068 shares in 2010 and 62,899,122 shares in 2009; outstanding, net of treasury shares: 63,007,433 shares in 2010 and 62,772,229 shares in 2009		631		629
Additional paid-in capital		174,973		160,516
Treasury stock, at cost: 102,635 shares in 2010 and 126,893 shares in 2009		(489)		(1,204)
Retained earnings		992,685		851,583
Accumulated other comprehensive income (loss)		15,033		(37,954)
Total stockholders equity		1,182,833		973,570
Total Liabilities and Stockholders Equity	**$**	**2,417,385**	**$**	**2,360,936**

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

SM ENERGY COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)

(In thousands, except per share amounts)

	For the Three Months Ended June 30, 2010	For the Three Months Ended June 30, 2009	For the Six Months Ended June 30, 2010	For the Six Months Ended June 30, 2009
Operating revenues and other income:				
Oil and gas production revenue	$ 175,887	$ 145,279	$ 388,774	$ 275,696
Realized oil and gas hedge gain	9,329	43,279	11,924	98,899
Gain on divestiture activity	7,021	1,244	127,999	645
Marketed gas system and other operating revenue	19,460	15,396	43,135	29,178
Total operating revenues and other income	211,697	205,198	571,832	404,418
Operating expenses:				
Oil and gas production expense	45,168	49,465	93,508	105,294
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	79,770	70,391	157,535	162,103
Exploration	14,498	19,490	28,396	33,088
Impairment of proved properties		6,043		153,092
Abandonment and impairment of unproved properties	2,375	11,631	3,279	15,533
Impairment of materials inventory		2,719		11,335
General and administrative	25,398	18,160	48,884	34,559
Change in Net Profits Plan liability	(6,599)	2,449	(33,871)	(20,842)
Marketed gas system expense	15,807	13,609	37,853	26,992
Unrealized derivative (gain) loss	(2,087)	11,288	(9,822)	13,134
Other expense	578	5,814	1,530	11,456
Total operating expenses	174,908	211,059	327,292	545,744
Income (loss) from operations	36,789	(5,861)	244,540	(141,326)
Nonoperating income (expense):				
Interest income	54	105	183	127
Interest expense	(6,343)	(7,663)	(13,130)	(13,759)
Income (loss) before income taxes	30,500	(13,419)	231,593	(154,958)
Income tax benefit (expense)	(12,432)	5,097	(87,347)	59,013
Net income (loss)	**$ 18,068**	**$ (8,322)**	**$ 144,246**	**$ (95,945)**
Basic weighted-average common shares outstanding	62,917	62,418	62,855	62,377
Diluted weighted-average common shares outstanding	64,566	62,418	64,493	62,377
Basic net income (loss) per common share	**$ 0.29**	**$ (0.13)**	**$ 2.29**	**$ (1.54)**
Diluted net income (loss) per common share	**$ 0.28**	**$ (0.13)**	**$ 2.24**	**$ (1.54)**

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

SM ENERGY COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY AND COMPREHENSIVE INCOME (LOSS) (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, December 31, 2009	**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 settlement of RSUs following expiration of restriction period, net of shares used for tax withholdings, including income tax cost of RSUs	34,588	1	(545)					(544)
Sale of common stock, including income tax benefit of stock option exercises	148,902	1	3,054					3,055
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**
Balances, December 31, 2008	**62,465,572**	**$ 625**	**$ 141,283**	**(176,987)**	**$ (1,892)**	**$ 957,200**	**$ 65,293**	**$ 1,162,509**
Comprehensive loss, net of tax:								
Net loss						(95,945)		(95,945)
Change in derivative instrument fair value							(11,852)	(11,852)
Reclassification to earnings							(45,494)	(45,494)
Minimum pension liability adjustment							4	4
Total comprehensive loss								(153,287)
Cash dividends, $ 0.05 per share						(3,120)		(3,120)
Issuance of common stock under Employee Stock Purchase Plan	49,767		858					858
Issuance of common stock upon settlement of RSUs following expiration of restriction period, net of shares used for tax withholdings, including income	86,505	1	(3,249)					(3,248)

tax cost of RSUs								
Sale of common stock, including income tax benefit of stock option exercises	19,570		207					207
Stock-based compensation expense	1,250		6,873	50,094	636			7,509
Balances, June 30, 2009	**62,622,664**	**$ 626**	**$ 145,972**	**(126,893)**	**$ (1,256)**	**$ 858,135**	**$ 7,951**	**$ 1,011,428**

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

SM ENERGY COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(In thousands)

	For the Six Months Ended June 30, 2010	2009
Cash flows from operating activities:		
Net income (loss)	$ 144,246	$ (95,945)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Gain on divestiture activity	(127,999)	(645)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	157,535	162,103
Exploratory dry hole expense	327	4,667
Impairment of proved properties		153,092
Abandonment and impairment of unproved properties	3,279	15,533
Impairment of materials inventory		11,335
Stock-based compensation expense	11,864	7,509
Change in Net Profits Plan liability	(33,871)	(20,842)
Unrealized derivative (gain) loss	(9,822)	13,134
Loss related to hurricanes		7,120
Amortization of debt discount and deferred financing costs	6,657	5,703
Deferred income taxes	78,820	(63,148)
Plugging and abandonment	(6,222)	(2,355)
Other	2,937	1,619
Changes in current assets and liabilities:		
Accounts receivable	7,628	49,149
Refundable income taxes	9,558	13,161
Prepaid expenses and other	(148)	(7,091)
Accounts payable and accrued expenses	26,299	(12,338)
Excess income tax benefit from the exercise of stock options	(938)	
Net cash provided by operating activities	**270,150**	**241,761**
Cash flows from investing activities:		
Net proceeds from sale of oil and gas properties	247,998	1,081
Capital expenditures	(304,627)	(215,826)
Acquisition of oil and gas properties		(44)
Deposits to restricted cash	(19,595)	
Receipts from restricted cash		14,398
Receipts from short-term investments		1,002
Other	(6,492)	
Net cash used in investing activities	**(82,716)**	**(199,389)**
Cash flows from financing activities:		
Proceeds from credit facility	204,059	1,766,000
Repayment of credit facility	(392,059)	(1,791,000)
Debt issuance costs related to credit facility		(11,060)
Proceeds from sale of common stock	2,916	1,066
Dividends paid	(3,144)	(3,120)
Excess income tax benefit from the exercise of stock options	938	
Other	(544)	
Net cash used in financing activities	**(187,834)**	**(38,114)**
Net change in cash and cash equivalents	(400)	4,258

Cash and cash equivalents at beginning of period		10,649		6,131
Cash and cash equivalents at end of period	**$**	**10,249**	**$**	**10,389**

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

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,	
	2010	2009
	(In thousands)	
Cash paid for interest	$ 8,152	$ 8,837
Cash refunded for income taxes	$ (2,392)	$ (10,441)

As of June 30, 2010, and 2009, $105.4 million, and $57.9 million, respectively, are included as additions to oil and gas properties and accounts payable and accrued expenses in the accompanying condensed consolidated balance sheets. These oil and gas additions are reflected as 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.

SM ENERGY COMPANY AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

June 30, 2010

Note 1 The Company and Business

SM Energy Company (SM Energy or the Company), formerly named St. Mary Land & Exploration Company or referred to as St. Mary, is an independent energy company engaged in the exploration, exploitation, development, acquisition, and production of natural gas, natural gas liquids, and crude oil. The Company s operations are conducted entirely in the continental United States.

Note 2 Basis of Presentation and Significant Accounting Policies

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, 2009, (the 2009 Form 10-K). In the opinion of management, all adjustments, consisting of normal recurring accruals that are considered necessary for a fair presentation of the 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 the condensed consolidated financial statements of SM Energy, the Company evaluated subsequent events after the balance sheet date of June 30, 2010, 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 2009 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 2009 Form 10-K.

Note 3 Divestitures and Assets Held for Sale

Legacy Divestiture

In February 2010 the Company completed the divestiture of certain non-strategic oil properties located in Wyoming to Legacy Reserves Operating LP, a wholly-owned subsidiary of Legacy Reserves LP (Legacy). The transaction had an effective date of November 1, 2009. Total cash received, before commission costs and Net Profits Interest Bonus Plan (Net Profits Plan) payments, was $125.2 million, of which $6.5 million was received as a deposit in December 2009. The final sale price is subject to normal post-closing adjustments and is expected to be finalized during the second half of 2010. The estimated gain on sale related to the divestiture is approximately $65.1 million and may be impacted by the forthcoming post-closing adjustments mentioned above. The Company determined that the sale does not qualify for discontinued operations accounting under Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 205, Presentation of Financial Statements (ASC Topic 205). A portion of the transaction was structured to qualify as a like-kind exchange under Section 1031 of the Internal Revenue Code of 1986, as amended (the Internal Revenue Code).

Sequel Divestiture

In March 2010 the Company completed the divestiture of certain non-strategic oil properties located in North Dakota to Sequel Energy Partners, LP, Bakken Energy Partners, LLC, and Three Forks Energy Partners, LLC (collectively referred to as Sequel). The transaction had an effective date of November 1, 2009. Total cash received, before commission costs and Net Profits Plan payments, was $126.9 million. The final sale price is subject to normal post-closing adjustments and is expected to be finalized during the second half of 2010. The estimated gain on sale related to the divestiture is approximately $50.4 million and may be impacted by the forthcoming post-closing adjustments mentioned above. The Company determined that the sale does not qualify for discontinued operations accounting under ASC Topic 205. A portion of the transaction was structured to qualify as a like-kind exchange under Section 1031 of the Internal Revenue Code.

Assets Held for Sale

In accordance with FASB ASC Topic 360, Property, Plant, and Equipment (ASC Topic 360), 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 determine if there is 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 if the fair value is determined to be less than the carrying value of the assets.

As of June 30, 2010, the accompanying condensed consolidated balance sheets present $7.1 million in book value of assets held for sale, net of accumulated depletion, depreciation, and amortization. Additionally, the corresponding asset retirement obligation liability of $1.5 million is separately presented. The Company determined that these planned asset sales do not qualify for discontinued operations accounting under ASC Topic 205. Subsequent to June 30, 2010, the Company has completely divested of the assets held for sale.

Note 4 Income Taxes

Income tax (expense) benefit for the six-month periods ended June 30, 2010, and 2009, differs from the amounts that would be provided by applying the statutory U.S. federal income tax rate to income (loss) 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,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
	(In thousands)			
Current portion of income tax (expense) benefit:				
Federal	$ 1,759	$ (2,166)	$ (8,216)	$ (3,249)
State	21	(495)	(311)	(886)
Deferred portion of income tax (expense) benefit	(14,212)	7,758	(78,820)	63,148
Total income tax (expense) benefit	$ (12,432)	$ 5,097	$ (87,347)	$ 59,013
Effective tax rate	40.8%	38.0%	37.7%	38.1%

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 between state tax jurisdictions resulting from Company activities. Non-core asset sales through June 30, 2010, and the Company s anticipated drilling budget for the rest of 2010 applied against the Company s cumulative temporary timing differences caused an increase in tax rate for the second quarter of 2010 when compared to the same period of 2009. The rate is also being impacted period to period as estimates for the domestic production activities deduction, percentage depletion and the impact of potential permanent state tax items affect the presented periods differently because of oil and gas price variability and the impact of non-core asset sales.

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 2006. In late 2009 the Internal Revenue Service announced a National Research Program (NRP) study of employment tax compliance that includes audits of randomly selected taxpayers for data collection purposes. During the first quarter of 2010, the Internal Revenue Service initiated an audit of SM Energy for the 2006 tax year focused primarily on compensation. In the second quarter of 2010 the Company determined its 2006 audit was not part of the NRP study. At June 30, 2010, the Company is awaiting a $5.5 million refund related to its 2006 tax year as a result of a net operating loss carry back from the Company s 2008 tax year. This refund claim was combined with the audit discussed above and cannot be received until the audit is completed and submitted to the Joint Committee on Taxation (JCT) for review. The Company believes the 2006 audit will conclude in the third quarter of 2010 with no material adjustments, and its claim will be submitted to the JCT soon thereafter. The Company s remaining refundable income tax balance at June 30, 2010, reflects its utilization of carry backs to claim a taxable net operating loss generated for the 2009 tax year against its 2005 taxable income. On July 20, 2010, the Company received $22.9 million relating to this carry back claim.

The Company s 2005 federal income tax audit was concluded in the first quarter of 2009 with a refund to the Company of $278,000 plus interest of $41,000. There was no change to the provision for income tax expense as a result of the 2005 examination.

Note 5 Earnings per Share

Basic net income or loss per common share of stock is calculated by dividing net income or loss available to common stockholders by the basic weighted-average common shares outstanding for the respective period. The shares represented by vested restricted stock units (RSUs) are included in the calculation of the basic weighted-average common shares outstanding. The earnings per share calculations reflect the impact of any repurchases of shares of common stock made by the Company.

Diluted net income or loss per common share of stock is calculated by dividing adjusted net income or loss by the diluted weighted-average common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the diluted earnings per share calculation consist of unvested 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 due 2027 (the 3.50% Senior Convertible Notes) are convertible.

The Company s 3.50% Senior Convertible Notes have a net-share settlement right whereby each $1,000 principal amount of notes may be surrendered for conversion to cash in an amount equal to the principal amount and, if applicable, 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. The treasury stock method is used to measure the potentially dilutive impact of shares associated with this conversion feature. The 3.50% Senior Convertible Notes have not been dilutive for any reporting period that they have been outstanding and therefore do not impact the diluted earnings per share calculation for the three-month and six-month periods ended June 30, 2010, and 2009.

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 be 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 7 Compensation Plans under the heading *Performance Share Awards Under the Equity Incentive Compensation Plan*.

The treasury stock method is used to measure the dilutive impact of stock options, RSUs, 3.50% Senior Convertible Notes, and PSAs. In accordance with FASB ASC Topic 260, Earnings Per Share when there is a loss from continuing operations, all potentially dilutive shares will be anti-dilutive. There were no dilutive shares for the three-month or six-month periods ended June 30, 2009, because the Company recorded a loss for each of those periods. Unvested RSUs, contingent PSAs, and in-the-money options had a dilutive impact for the three-month and six-month periods ended June 30, 2010, as calculated in the table below.

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

	For the Three Months Ended June 30, 2010	For the Three Months Ended June 30, 2009	For the Six Months Ended June 30, 2010	For the Six Months Ended June 30, 2009
	(In thousands, except per share amounts)			
Net income (loss)	$ 18,068	$ (8,322)	$ 144,246	$ (95,945)
Basic weighted-average common stock outstanding	62,917	62,418	62,855	62,377
Add: dilutive effect of stock options, unvested RSUs, and contingent PSAs	1,649		1,638	
Add: dilutive effect of 3.50% senior convertible notes				
Diluted weighted-average common shares outstanding	64,566	62,418	64,493	62,377
Basic net income (loss) per common share	$ 0.29	$ (0.13)	$ 2.29	$ (1.54)
Diluted net income (loss) per common share	$ 0.28	$ (0.13)	$ 2.24	$ (1.54)

Note 6 Commitments and Contingencies

In February 2010 the Company entered into an agreement whereby it is subject to certain natural gas gathering through-put commitments that require a minimum volume delivery of 100 Bcf by the end of the ten year contract term. As of June 30, 2010, the pipeline volume commitments associated with this agreement for the next five years and thereafter are presented below:

Years Ending December 31,	Committed Volumes (In Bcf)		Undiscounted Cash Outflows (In thousands)
2010	3.0	$	540
2011	6.0		1,080
2012	6.0		1,080
2013	10.0		1,800
2014	10.0		1,800
Thereafter	65.0		11,700
Total	100.0	$	18,000

On July 2, 2010, the Company entered into an agreement whereby it is subject to certain natural gas gathering through-put commitments during the ten year contract term. The Company will be required to make periodic deficiency payments for any shortfalls in delivering the minimum volume commitments. In the event that no gas is delivered pursuant to the agreement, the aggregate deficiency payments will total $154.7 million over the life of the contract.

Note 7 Compensation Plans

Cash Bonus Plan

During the first quarters of 2010 and 2009, the Company paid $7.7 million and $6.0 million for cash bonuses earned in the 2009 and 2008 performance years, respectively. Within the general and administrative expense and exploration expense line items in the accompanying condensed consolidated statements of operations is $2.9 million of cash bonus expense related to the specific performance year for each of the three-month periods ended June 30, 2010, and 2009, and $6.0 million and $5.3 million for the six-month periods ended June 30, 2010, and 2009, respectively.

Performance Share Awards Under the Equity Incentive Compensation Plan

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 be from zero to two times the number of PSAs granted on the award date, depending on the extent to which the Company s performance criteria have been achieved and the extent to which the PSAs have vested. The performance criteria for the PSAs are based on a combination of the Company s total shareholder return (TSR) for the performance period and the relative performance of the Company s TSR compared with the TSR of an index of certain peer companies for the performance period.

Total stock-based compensation expense related to PSAs for the three-month periods ended June 30, 2010, and 2009, was $3.8 million and $1.1 million, respectively, and $7.4 million and $2.5 million for the six-month periods ended June 30, 2010, and 2009, respectively. As of June 30, 2010, there was $14.7 million of total unrecognized compensation expense related to unvested PSAs. The unrecognized compensation expense will be amortized through 2012.

A summary of the status and activity of PSAs for the six-month period ended June 30, 2010, is presented in the following table:

	PSAs		Weighted-Average Grant-Date Fair Value
Non-vested, at January 1, 2010	1,069,090	$	32.52
Granted		$	
Vested	(8,128)	$	30.50
Forfeited	(87,527)	$	31.73
Non-vested and outstanding, at June 30, 2010	973,435	$	32.61

Subsequent to June 30, 2010, the Company granted 387,651 PSAs as part of its regular annual compensation process. These PSAs will vest 1/7th on July 1, 2011, 2/7ths on July 1, 2012, and 4/7ths on July 1, 2013.

Restricted Stock Unit Incentive Program Under the Equity Incentive Compensation Plan

Total RSU compensation expense for both the three-month periods ended June 30, 2010, and 2009, was $1.7 million, and $3.5 million and $3.8 million for the six-month periods ended June 30, 2010, and 2009, respectively. As of June 30, 2010, there was $5.4 million of total unrecognized compensation expense related to unvested RSU awards. The unrecognized compensation expense will be amortized through 2012.

During the first half of 2010, the Company settled 51,115 RSUs that relate to awards granted in 2008 and 2007 through the issuance of shares of the Company s common stock in accordance with the terms of the RSU awards. The Company and the majority of the grant participants mutually agreed to net-share settle the awards to cover income and payroll tax withholdings as provided for in the plan document and the award agreements. As a result, the Company issued 34,588 shares of common stock associated with these grants. The remaining 16,527 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon the delivery of the shares underlying those RSUs.

A summary of the status and activity of RSUs for the six-month period ended June 30, 2010, is presented in the following table:

	RSUs		Weighted-Average Grant-Date Fair Value
Non-vested, at January 1, 2010	407,123	$	34.67
Granted		$	
Vested	(49,882)	$	36.23
Forfeited	(26,877)	$	36.48
Non-vested and outstanding, at June 30, 2010	330,364	$	34.28

Subsequent to June 30, 2010, the Company granted 126,821 RSUs as part of its regular annual compensation process. Each RSU represents a right to receive one share of the Company s common stock

to be delivered upon settlement of the vested RSUs. These RSUs will vest 1/7th on July 1, 2011, 2/7ths on July 1, 2012, and 4/7ths on July 1, 2013.

Stock Option Grants Under Prior Stock Option Plans

The following table summarizes stock option activity for the six months ended June 30, 2010:

	Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (In years)	Aggregate Intrinsic Value (In thousands)
Outstanding, at January 1, 2010	1,274,920	$ 13.31		
Exercised	(148,902)	$ 14.22		
Forfeited		$		
Outstanding, end of period	1,126,018	$ 13.19	2.6	$ 30,369
Vested, or expect to vest, at end of period	1,126,018	$ 13.19	2.6	$ 30,369
Exercisable, end of period	1,126,018	$ 13.19	2.6	$ 30,369

As of June 30, 2010, there was no unrecognized compensation expense related to stock option awards.

Director Shares

In May 2010 and 2009 the Company issued 24,258 and 50,094 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 $690,000 and $517,000 of compensation expense for the three-month periods ended June 30, 2010, and 2009, respectively, and $715,000 and $636,000 for the six-month periods ended June 30, 2010, and 2009, respectively.

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, and shares issued under the ESPP are restricted for a period of six months from the date issued. 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 1,440,819 shares are available for issuance as of June 30, 2010. The fair value of ESPP grants is measured at the date of grant using the Black-Scholes option-pricing model. There were 27,456 and 49,767 shares issued under the ESPP during the first half of 2010 and 2009, respectively. The Company expensed $124,000 and $390,000 for the three-month periods ended June 30, 2010, and 2009, respectively, and $263,000 and $541,000 for the six-month periods ended June 30, 2010, and 2009, respectively, based on the estimated fair values on the respective grant dates.

Net Profits Plan

Prior to 2008, all oil and gas wells that were completed or acquired during each year were assigned to a specific pool for that respective year under the Company s legacy Net Profits Plan. Key employees become entitled to payments under the Net Profits Plan after the Company has received net cash flows returning 100 percent of all costs associated with a 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 the pool to be allocated among the participants increases to 20 percent after the Company has recovered both 200 percent of the total costs for the pool and 100 percent of pool payments made under the Net Profits Plan at the ten percent level. 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,			
	2010		2009		2010		2009	
	(In thousands)							
General and administrative expense	$	5,381	$	4,541	$	12,315	$	7,774
Exploration expense		667		471		1,258		876
Total	$	6,048	$	5,012	$	13,573	$	8,650

Additionally, the Company made cash payments under the Net Profits Plan of $1.9 million and $20.1 million for the three-month and six-month periods ended June 30, 2010, respectively, as a result of sales proceeds mainly from the Legacy and Sequel divestitures. The cash payments are accounted for as a reduction of proceeds, which reduced the gain (loss) on divestiture activity in the accompanying condensed consolidated statements of operations. There were no cash payments made under the Net Profits Plan as a result of divestitures that occurred during the first half of 2009.

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 condensed consolidated 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. The table below presents the estimated allocation of the change in the liability if the Company did allocate the adjustment to these specific functional line items based on the current allocation of actual distributions made by the Company. As time progresses, less of the distributions relate to prospective exploration efforts as more of the distributions are made to participants that have terminated employment and do not provide ongoing exploration support to the Company.

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
	2010		2009		2010		2009	
	(In thousands)							
General and administrative expense (benefit)	$	(5,959)	$	1,964	$	(32,604)	$	(18,730)
Exploration expense (benefit)		(640)		485		(1,267)		(2,112)
Total	$	(6,599)	$	2,449	$	(33,871)	$	(20,842)

Note 8 Pension Benefits

Pension Plans

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

Components of Net Periodic Benefit Cost for Both Plans

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

	For the Three Months Ended June 30, 2010	For the Three Months Ended June 30, 2009	For the Six Months Ended June 30, 2010	For the Six Months Ended June 30, 2009
	(In thousands)			
Service cost	$ 848	$ 625	$ 1,696	$ 1,250
Interest cost	280	233	560	467
Expected return on plan assets	(159)	(107)	(318)	(215)
Amortization of net actuarial loss	91	93	182	186
Net periodic benefit cost	$ 1,060	$ 844	$ 2,120	$ 1,688

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

Under the Pension Protection Act of 2006, SM Energy is not required to make a minimum contribution to the pension plans in 2010.

Note 9 Asset Retirement Obligations

The Company recognizes an estimated liability for future costs associated with the plugging and abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and a corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is completed or acquired. The increase in carrying value is included in proved oil and gas properties in the accompanying condensed consolidated balance sheets. The Company depletes the amount added to proved oil and gas property costs and recognizes expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and gas properties. Cash paid to settle asset retirement obligations is included in the operating section of the Company s accompanying condensed consolidated statements of cash flows.

The Company s estimated asset retirement obligation liability is based on estimated economic lives, historical experience in plugging and abandoning wells, estimated cost to plug and abandon the wells in the future, and federal and state regulatory requirements. The liability is discounted using a credit-adjusted risk-free rate estimated at the time the liability is incurred or revised. The credit-adjusted risk-free rates used to discount the Company s abandonment liabilities range from 6.5 percent to 12.0 percent. Revisions to the liability could occur due to changes in estimated abandonment costs or well commerciality, or if federal or state regulators enact new requirements regarding the abandonment of wells. The asset retirement obligation is considered settled when the well has been plugged and abandoned or divested.

A reconciliation of the Company s asset retirement obligation liability is as follows:

		For the Six Months Ended June 30, 2010 (In thousands)
Beginning asset retirement obligation	$	102,080
Liabilities incurred		1,373
Liabilities settled		(24,583)
Accretion expense		2,845
Revision to estimated cash flow		(715)
Ending asset retirement obligation	$	81,000

As of June 30, 2010, the Company had $1.5 million of asset retirement obligation associated with the oil and gas properties held for sale included in a separate line item on the Company s accompanying condensed consolidated balance sheets. Additionally, as of June 30, 2010, accounts payable and accrued expenses contained $15.2 million related to the Company s current asset retirement obligation liability associated with the estimated retirement of some of the Company s offshore platforms.

Note 10 Derivative Financial Instruments

Oil, Natural Gas and NGL Commodity Hedges

To mitigate a portion of the exposure to potentially adverse market changes in oil and gas prices and the associated impact on cash flows, the Company has entered into various derivative contracts. The Company s derivative contracts in place include swap and collar arrangements for oil, natural gas, and natural gas liquids (NGLs). As of June 30, 2010, the Company has hedge contracts in place through the first quarter of 2013 for a total of approximately 5 million Bbls of anticipated crude oil production, 46 million MMBtu of anticipated natural gas production, and 2 million Bbls of anticipated natural gas liquids production. As of July 28, 2010, the Company has hedge contracts in place through the second quarter of 2013 for a total of approximately 6 million Bbls of anticipated crude oil production, 50 million MMBtu of anticipated natural gas production, and 2 million Bbls of anticipated natural gas liquids production.

The Company attempts to qualify its oil, natural gas, and NGL derivative instruments as cash flow hedges for accounting purposes under FASB ASC Topic 815, Derivatives and Hedging (ASC Topic 815). The Company formally documents all relationships between the derivative instruments and the hedged production, as well as the Company s risk management objective and strategy for the particular derivative contracts. This process includes linking all derivatives that are designated as cash flow hedges to the specific forecasted sale of oil, natural gas or NGLs. The Company also formally assesses (both at the derivative s inception and on an ongoing basis) whether the derivatives being utilized have been highly effective in offsetting changes in the cash flows of hedged production and whether those derivatives may be expected to remain highly effective in future periods. If it is determined that a derivative has ceased to be highly effective as a hedge, the Company will discontinue hedge accounting for that derivative prospectively. If hedge accounting is discontinued and the derivative remains outstanding, the Company will recognize all subsequent changes in its fair value in the Company s consolidated statements of operations for the period in which the change occurs. As of June 30, 2010, all oil, natural gas, and NGL derivative instruments qualified as cash flow hedges for accounting purposes. The Company anticipates that all forecasted transactions will occur by the end of their originally specified periods. All contracts are entered into for other-than-trading purposes.

The Company s oil, natural gas, and NGL hedges are measured at fair value and are included in the accompanying condensed consolidated balance sheets as derivative assets and liabilities. The Company derives internal valuation estimates taking into consideration the counterparties credit worthiness, the Company s credit worthiness, and the time value of money. Those internal valuations are then compared to the counterparties mark-to-market statements. The consideration of the factors results in an estimated exit-price for each derivative asset or liability under a market place participant s view. Management believes that this approach provides a reasonable, non-biased, verifiable, and consistent methodology for valuing commodity 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 derivative contracts designated and qualifying as cash flow hedges under ASC Topic 815 was a net asset of $13.7 million and a net liability of $80.9 million at June 30, 2010, and December 31, 2009, respectively.

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

	Location on Consolidated Balance Sheets	Fair Value at June 30, 2010	Fair Value at December 31, 2009
		(In thousands)	
Derivative assets designated as cash flow hedges:			
Oil, natural gas, and NGL commodity	Current assets	$ 45,481	$ 30,295
Oil, natural gas, and NGL commodity	Other noncurrent assets	30,169	8,251
Total derivative assets designated as cash flow hedges under ASC Topic 815		$ 75,650	$ 38,546
Derivative liabilities designated as cash flow hedges:			
Oil, natural gas, and NGL commodity	Current liabilities	$ (37,903)	$ (53,929)
Oil, natural gas, and NGL commodity	Noncurrent liabilities	(24,046)	(65,499)
Total derivative liabilities designated as cash flow hedges under ASC Topic 815		$ (61,949)	$ (119,428)

Realized gains or losses from the settlement of oil, natural gas, and NGL derivative contracts are reported in the total operating revenues and other income section of the accompanying condensed consolidated statements of operations. The Company realized a net gain of $9.3 million and $43.3 million from its oil, natural gas, and NGL derivative contracts for the three months ended June 30, 2010, and 2009, respectively, and realized a net gain of $11.9 million and $98.9 million from its oil, natural gas, and NGL derivative contracts for the six months ended June 30, 2010, and 2009, respectively.

After-tax changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributed to the hedged risk, are recorded in accumulated other comprehensive income in the accompanying condensed consolidated balance sheets until the hedged item is realized in earnings upon the sale of the associated hedged production. As of June 30, 2010, the amount of unrealized gain (loss) net of deferred income taxes to be reclassified from accumulated other comprehensive income to realized oil and gas hedge gain (loss) in the Company s accompanying condensed consolidated statements of operations in the next twelve months is $11.3 million.

The Company seeks to minimize ineffectiveness by entering into oil derivative contracts indexed to the New York Mercantile Exchange West Texas Intermediate (NYMEX WTI) index, natural gas derivative contracts indexed to regional index prices associated with pipelines in proximity to the Company s areas of production, and NGL derivative contracts indexed to Oil Price Information Service Mont Belvieu. The Company s derivative contracts utilize the same respective indices or pricing points as

the Company s sales contracts. As a result, the derivative contracts used by the Company are highly correlated with the underlying hedged production.

The following table details the effect of derivative instruments on other comprehensive income (loss) and the condensed consolidated balance sheets (net of income tax):

	Derivatives Qualifying as Cash Flow Hedges	For the Six Months Ended June 30, 2010		For the Six Months Ended June 30, 2009	
		(In thousands)			
Amount of (gain) loss on derivatives recognized in OCI during the period (effective portion)	Commodity hedges	$	(53,765)	$	11,852
Amount of (gain) loss reclassified from AOCI to realized oil and gas hedge gain (loss) (effective portion)	Commodity hedges	$	(782)	$	(45,494)

Any change in fair value resulting from hedge ineffectiveness is recognized currently in unrealized derivative (gain) loss in the accompanying condensed consolidated statements of operations. The following table details the effect of derivative instruments on the condensed consolidated statements of operations:

Derivatives Qualifying as Cash Flow Hedges	Classification of (Gain) Loss Recognized in Earnings	(Gain) Loss Recognized in Earnings (Ineffective Portion)							
		For the Three Months Ended June 30, 2010		2009		For the Six Months Ended June 30, 2010		2009	
		(In thousands)							
Commodity hedges	Unrealized derivative (gain) loss	$	(2,087)	$	11,288	$	(9,822)	$	13,134

Credit Related Contingent Features

As of June 30, 2010, only one of the Company s hedge counterparties was not a member of the Company s credit facility bank syndicate. Member banks are secured by the Company s oil and gas assets, and therefore do not require the Company to post collateral in instances where the Company is in a liability position. When the Company is in a liability position with a non-member bank, posting of collateral may be required if the Company s liability balance exceeds the limit set forth in the agreement with the non-member bank. With the one non-member bank, the amount of collateral, if any, that the Company is required to post depends on a number of financial metrics that are calculated quarterly. No collateral was posted as of June 30, 2010, or July 28, 2010.

Convertible Note Derivative Instruments

The contingent interest provision of the 3.50% Senior Convertible Notes is an embedded derivative instrument. As of June 30, 2010, and December 31, 2009, the value of this derivative was determined to be immaterial.

Note 11 Fair Value Measurements

The Company follows the authoritative accounting guidance under FASB ASC Topic 820, Fair Value Measurements and Disclosures (ASC Topic 820) for all assets and liabilities measured at fair value. ASC Topic 820 establishes a framework for measuring fair value and requires enhanced disclosures about fair value measurements. ASC Topic 820 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. The topic establishes market or observable inputs as the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The topic establishes a hierarchy for grouping these assets and liabilities 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, 2010:

	Level 1	Level 2	Level 3

			(In thousands)			
Assets:						
Derivatives	$		$	75,650	$	
Liabilities:						
Derivatives	$		$	61,949	$	
Net Profits Plan	$		$		$	136,420

There were no nonfinancial assets or liabilities measured at fair value on a nonrecurring basis at June 30, 2010.

The following is a listing of the Company s assets and liabilities that are measured at fair value and where they are classified within the hierarchy as of December 31, 2009:

	Level 1	Level 2	Level 3
		(In thousands)	
Assets:			
Derivatives(a)	$	$ 38,546	$
Proved oil and gas properties(b)	$	$	$ 11,740
Materials inventory(b)	$	$ 13,882	$
Liabilities:			
Derivatives(a)	$	$ 119,428	$
Net Profits Plan(a)	$	$	$ 170,291

(a) This represents a financial asset or liability that is measured at fair value on a recurring basis.

(b) This represents a nonfinancial asset or liability that is measured at fair value on a nonrecurring basis.

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

Derivatives

The Company uses Level 2 inputs to measure the fair value of oil and gas hedges. 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 may attempt to novate trades with parties deemed to have more risk on a relative basis to a more stable and less risky 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. The majority 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 the requirements of ASC Topic 820 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 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 and their impact on net cash flows and the amount of 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 a predominate number of the pools, a discount rate of 12 percent is used to calculate this liability. This rate is 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 price, 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 was determined using price assumptions that were computed using five one-year strip prices with the fifth year s pricing being carried out indefinitely. The average price was adjusted to include the effects of hedge prices for the percentage of forecasted production hedged 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 and natural gas commodity markets.

If the commodity prices used in the calculation changed by five percent, the liability recorded at June 30, 2010, would differ by approximately $11 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 $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. 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 liabilities measured at fair value using Level 3 inputs:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
	(In thousands)			
Beginning balance	$ 143,019	$ 154,075	$ 170,291	$ 177,366
Net increase (decrease) in liability (a)	1,318	7,461	(218)	(12,192)
Net settlements (a)(b)	(7,917)	(5,012)	(33,653)	(8,650)
Transfers in (out) of Level 3				
Ending balance	$ 136,420	$ 156,524	$ 136,420	$ 156,524

(a) Net changes in the Net Profits Plan liability are shown in the Change in Net Profits Plan liability line item of the accompanying condensed consolidated statements of operations.

(b) Settlements represent cash payments made or accrued under the Net Profits Plan and include $1.9 million and $20.1 million of cash payments related primarily to the Legacy and Sequel divestitures for the three-month and six-month periods ending June 30, 2010, respectively. There were no cash payments made under the Net Profits Plan as a result of divestitures that occurred during the first half of 2009.

3.50% Senior Convertible Notes Due 2027

Based on the market price of the 3.50% Senior Convertible Notes, the estimated fair value of the notes was approximately $306 million and $290 million as of June 30, 2010, and December 31, 2009, respectively.

Proved Oil and Gas Properties

Proved oil and gas property costs are evaluated for impairment and reduced to fair value if the sum of the expected undiscounted future cash flows is less than net book value pursuant to ASC Topic 360. 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 discount rate is a rate that management believes is representative of current market conditions and includes the following factors: estimates of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk. The price forecast is based on NYMEX strip pricing, adjusted for basis differentials, for the first five years. Future operating costs are also adjusted as deemed appropriate for these estimates.

In accordance with ASC Topic 820, of the $2.1 billion of long-lived assets, excluding materials inventory, $11.7 million were measured at fair value at December 31, 2009. There were no long-lived assets measured at fair value within the accompanying condensed consolidated balance sheets at June 30, 2010.

Asset Retirement Obligations

The Company estimates asset retirement obligations pursuant to the provisions of FASB ASC Topic 410, Asset Retirement and Environmental Obligations. The income valuation technique is utilized by the Company to determine the fair value of the liability at the point of inception by applying a credit-adjusted risk-free rate, which takes into account the Company s credit risk, the time value of money, and the current economic state, to the undiscounted expected abandonment cash flows. Given the unobservable nature of the inputs, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. There were no asset retirement obligations measured at fair value within the accompanying consolidated balance sheets at June 30, 2010, or December 31, 2009.

Refer to Note 10 Derivative Financial Instruments and Note 9 Asset Retirement Obligations for more information regarding the Company s hedging instruments and asset retirement obligations.

Note 12 Recent Accounting Pronouncements

The Company partially adopted FASB ASC Update 2010-06, Fair Value Measurements and Disclosures Improving Disclosures about Fair Value Measurements (ASC Update 2010-06) that requires additional disclosures surrounding transfers between Levels 1 and 2, inputs and valuation techniques used to value Level 2 and 3 measurements, and push down of previously prescribed fair value disclosures to each class of asset and liability for Levels 1, 2, and 3. These disclosures were effective for the Company for the quarter ended March 31, 2010. The partial adoption of this pronouncement did not have a material impact on the Company s consolidated financial statements.

ASC Update 2010-06 also requires that purchases, sales, issuances, and settlements for Level 3 measurements be disclosed. This portion of the new authoritative guidance is effective for interim and annual reporting periods beginning after December 15, 2010. The Company will apply this new guidance in the Company s Quarterly Report on Form 10-Q for the period ended March 31, 2011. The adoption of these portions of ASC Update 2010-06 are not expected to have a material impact on the Company s financial statements.

The Company adopted FASB ASC Update 2010-09, Subsequent Events - Amendments to Certain Recognition and Disclosure Requirements, that removes the requirement for SEC filers to disclose the date through which an entity has evaluated subsequent events. However, the date-disclosure exemption does not relieve management of an SEC filer from its responsibility to evaluate subsequent events through the date on which financial statements are issued. This authoritative guidance was effective upon issuance on February 24, 2010. The adoption of this pronouncement did not have a material impact on the Company s consolidated financial statements.

Note 13 Carry and Earning Agreement

On April 29, 2010, the Company entered into a Carry and Earning Agreement (the CEA), which effectively provides for a third party to earn 95 percent of SM Energy s interest in approximately 8,400 net acres in a portion of the Company s East Texas Haynesville shale acreage, as well as an interest in several wells and five percent of SM Energy s interest in approximately 23,400 net acres in a separate portion of the Company s Haynesville acreage in East Texas. In exchange for these interests, the third party has agreed to invest $91.3 million to fund the drilling and completion costs of horizontal wells in the portion of the leases where the Company is retaining 95 percent of its current interest. Of this, $86.7 million represents SM Energy s carried drilling and completion costs, being 95 percent of the total amount invested by the third party. The

Company received an initial payment of $45.6 million on April 29, 2010, and the CEA provides that the Company will receive the balance of the committed funds less any adjustments allowed under the CEA for title defects within 30 days of the completion of the fourth commitment well. Once SM Energy has completed the expenditure of the total carry amount, the parties will share all costs of operations within the area of joint ownership in accordance with their respective ownership interests.

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 focused on the development, exploration, exploitation, acquisition, and production of natural gas, natural gas liquids, and crude oil in the continental United States. Generally, we generate nearly all our revenues and cash flows from the sale of produced natural gas and crude oil. In the first half of 2010 we have generated significant gains and cash proceeds from the sale of non-strategic oil and gas properties. Our oil and gas reserves and operations are concentrated primarily in the Rocky Mountain Williston Basin; the Mid-Continent Anadarko and Arkoma basins; the Permian Basin; the productive formations of East Texas and North Louisiana; north central Pennsylvania; the Maverick Basin in South Texas; and the onshore Gulf Coast. We have developed a balanced and diverse portfolio of proved reserves, development drilling opportunities, and unconventional resource prospects.

Our mission is to deliver outstanding net asset value per share growth to our investors via attractive oil and gas investments. Our strategy is to focus on early entrance into existing and emerging resource plays in North America. By entering these plays earlier, we believe that we can capture larger resource potential at lower cost. We believe this organic-centered model allows for more stable and predictable production and proved reserves growth.

Financial Standing and Liquidity

In the first quarter of 2010, the borrowing base on our credit facility was redetermined by our bank group and maintained at a value of $900 million despite the divestiture of non-strategic Rocky Mountain oil properties during the quarter. The commitment amount of the bank group remained unchanged at $678 million. At the end of the second quarter 2010 and through the filing date of this report, we had no outstanding borrowings under the revolving credit facility. We have no debt maturities until 2012, at which time our credit facility matures and our outstanding convertible notes can be put to us. Given our debt and asset levels, credit standing, and relationships with the participants in our bank group, we believe we will be able to extend or obtain a replacement credit facility before our current credit facility matures in 2012. We also believe our convertible notes could be put to us in 2012, at which time we have the option of settling with some combination of cash and/or common stock. The condition of the capital markets has improved significantly since last year, and therefore we believe we could access capital through the public markets, if necessary, to redeem these notes.

We expect our generated cash flows from operations in 2010 plus proceeds from our Rocky Mountain oil and other non-core asset divestitures to fund the majority of our capital budget for 2010. We plan to use our credit facility to fund the remaining balance of our capital program. Accordingly, we do not anticipate accessing the equity or public debt markets for the remainder of 2010. Given the size of and commitments associated with our existing inventory of potential drilling projects, our needs for capital could increase significantly in 2011 and beyond. As a result, we may consider accessing the capital markets, as well as other alternatives, as we determine how to best fund our capital program. We continue to believe we have adequate liquidity available as discussed under the caption Overview of Liquidity and Capital Resources.

Oil and Gas Prices

Our financial condition and the results of our operations are significantly affected by the prices we receive for oil, natural gas, and natural gas liquids, which can fluctuate dramatically. Please refer to *Comparison of Financial Results and Trends between the three months ended June 30, 2010, and 2009* for our realized price tables. We sell a 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. We account for our natural gas sales as they occur at the wellhead and accordingly do not present a separate production stream for natural gas liquids that are processed from our natural gas production. We receive value for the NGL content in our natural gas stream, which can result in us realizing a higher per unit price for our reported gas production. Our crude oil is 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 crude oil is produced, adjusted for quality, transportation, and location differentials. The following table is a summary of commodity price data for the second quarters of 2010 and 2009 and the first quarter of 2010:

	For the Three Months Ended		
	June 30, 2010	**March 31, 2010**	**June 30, 2009**
Crude Oil (per Bbl):			
Average NYMEX price	$ 77.88	$ 78.84	$ 59.69
Realized price, before the effects of hedging	$ 70.92	$ 72.73	$ 53.96
Net realized price, including the effects of hedging	$ 65.17	$ 66.96	$ 56.72
Natural Gas (per Mcf):			
Average NYMEX price	$ 4.33	$ 5.09	$ 3.71
Realized price, before the effects of hedging	$ 4.54	$ 6.15	$ 3.07
Net realized price, including the effects of hedging	$ 5.59	$ 6.84	$ 5.19

We expect future prices for oil, NGLs, and natural gas 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. Generally, NGL prices historically 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 negatively impact future pricing. Future natural gas prices are facing downward pressure as a result of a perceived supply overhang resulting from increased levels of drilling activity across the country, as well as tepid demand recovery due to the recession. The 12-month strip prices for NYMEX WTI crude oil and NYMEX Henry Hub gas as of June 30, 2010, were $77.74 per Bbl and $5.07 per MMBTU, respectively. Comparable prices as of July 28, 2010, were $79.69 per Bbl and $4.99 per MMBTU, respectively.

While changes in quoted NYMEX oil and natural gas prices are generally used as a basis for comparison within our industry, the price we receive for oil and natural gas is affected by quality, energy content, location, and transportation differentials for these products. We refer to this price as our realized price, which excludes the effects of hedging. Our realized price is further impacted by the results of our hedging arrangements that are settled in the respective periods. We refer to this price as our net realized price. For the three months ended June 30, 2010, our net natural gas price realization was positively impacted by $17.4 million of realized hedge settlements and our net oil price realization was negatively impacted by $8.1 million of realized hedge settlements.

Hedging Activities

On July 21, 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. In addition, the legislation provides an exemption from mandatory clearing requirements based on regulations to be developed by the Commodity Futures Trading Commission and the Securities and Exchange Commission for transactions by non-financial institutions to hedge or mitigate commercial risk. At the same time, the legislation includes provisions under which the CFTC may impose collateral requirements for transactions, including those that are used to hedge commercial risk. However, during drafting of the legislation, members of Congress adopted report language and issued a public letter stating that it was not their intention to impose margin and collateral requirements on counterparties that utilize transactions to hedge commercial risk. Final rules on major provisions in the legislation, like new margin requirements, will be established through rulemakings and will not take effect until 12 months after the date of enactment. Although we cannot predict the ultimate outcome of these rulemakings, new regulations in this area may result in increased costs and cash collateral requirements for the types of oil and gas derivative instruments we use to hedge and otherwise manage our financial risks related to volatility in oil and gas commodity prices.

Hedging is an important part of our financial risk management program. We have a Board-authorized financial risk management policy that governs our practices related to hedging. The amount of production we hedge is driven by the amount of debt on our consolidated balance sheet and the level of capital commitments and long-term obligations we have in place. In the case of a significant acquisition of producing properties, we will consider hedging a portion of the acquired production in order to protect the economics assumed in the acquisition. With the hedges we have in place, we believe we have established a base cash flow stream for our future operations, and our use of collars for a portion of the hedges allows us to participate in upward movements in oil and gas 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 and gas hedges, and see the caption, *Summary of Oil and Gas Production Hedges in Place,* later in this section.

We attempt to qualify our oil and gas derivative instruments as cash flow hedges for accounting purposes under ASC Topic 815. Changes in the value of our hedge positions are primarily reflected in our consolidated balance sheets. A portion of the change in the value of our hedge positions is recognized in our consolidated statements of operations due to hedges being partially ineffective at offsetting the fluctuations in cash flow due to change in the spot price for oil, natural gas and natural gas liquids. We recognized $2.1 million in non-cash unrealized derivative gain in the second quarter of 2010. Changes in the fair value of our hedge portfolio from March 31, 2010, through June 30, 2010, was primarily caused by decreases in prices of natural gas on the indexes on which we have hedges. As a result, our hedge position changed from a $22.4 million net liability at the end of the first quarter of 2010 to a $13.7 million net asset at the end of the second quarter of 2010. Corresponding changes are reflected in accumulated other comprehensive income on the consolidated balance sheets and unrealized derivative (gain) loss on the statement of operations.

Second Quarter 2010 Highlights

Operational activities. During the second quarter, we had an average of nine operated drilling rigs running company-wide. The thrust of our operated drilling activities this year has been focused on oil and NGL-rich gas programs and selected projects of potential strategic importance to the Company. Additionally, our operating partners have increased their levels of activity in oil and NGL-rich gas plays.

In the Eagle Ford shale in South Texas, we continued to operate two drilling rigs on our acreage during the second quarter. Our focus was on drilling in areas with higher MMBTU gas content and higher condensate yields. We have continued to test different ways to drill and complete these wells with the objective of optimizing our future development potential. Securing infrastructure to transport and process

production from the Eagle Ford has been an issue we have worked to address over the last year, particularly in recent months. Subsequent to quarter end, we entered into a gas services agreement whereby we committed a significant amount of production from the Eagle Ford to a ten year transportation and processing arrangement beginning in 2011. This agreement has shortfall penalties in the event that we are unable to deliver the committed volumes of gas. We are continuing to explore other arrangements to further address our infrastructure needs for this program. On our outside-operated acreage in the Eagle Ford, our operating partner has increased their rig count to six rigs at quarter-end, up from two rigs earlier in the year. This outside-operated acreage has limited infrastructure to support the development of the play and as a result we have been participating in the construction of infrastructure with our partner. The increase in partner-operated rigs and the infrastructure build-out have resulted in higher capital expenditures in this program than we initially planned for at the beginning of the year.

We operated an average of two drilling rigs in the Williston Basin during the second quarter of the year, both of which were focused on Bakken and Three Forks drilling. Our results in this program have met or exceeded expectations as several strong wells came online in the second quarter. Partners in the Williston Basin have steadily increased their activity during the second quarter. Elsewhere in the Rocky Mountain region, we drilled and completed our first operated horizontal well targeting the Niobrara formation in southeastern Wyoming. Interest in the Niobrara formation increased significantly during the first half of 2010 based on positive field reports coming out of the play. Our early results have been encouraging from this exploratory program.

In our Mid-Continent region, we drilled our first two wells in the horizontal Granite Wash in Beckham County in western Oklahoma. One of these wells was highly productive with strong condensate and NGL-rich gas contribution. Our acreage position is held by production and given the multiple productive formations in the play, we think the potential from this emerging program could be significant.

The Permian region ran two operated rigs in the second quarter, with the focus of the activity being on Wolfberry tight oil targets. In our operated Haynesville shale program, we had one or two drilling rigs operating in the play for most of the quarter and we are currently awaiting the completion of several wells. In the Marcellus shale, our first well in the play was turned to sales during the quarter and we continued to work on the gathering line that will service development of our acreage in McKean County, Pennsylvania.

Financial and production results. We recorded net income for the quarter ended June 30, 2010, of $18.1 million or $0.28 per diluted share compared to second quarter 2009 results of a net loss of $8.3 million or $0.13 per diluted share.

The table below details the regional breakdown of our second quarter 2010 production:

	Mid-Continent	**ArkLaTex**	**South Texas & Gulf Coast**	**Permian**	**Rocky Mountain**	**Total (1)**
Second Quarter 2010 Production:						
Oil (MBbl)	45.9	20.7	181.0	438.2	726.3	1,412.2
Gas (MMcf)	7,894.3	3,170.5	3,147.5	1,074.1	1,390.8	16,677.3
Equivalent (MMCFE)	8,169.6	3,294.9	4,233.6	3,703.6	5,748.7	25,150.5
Avg. Daily Equivalents (MMCFE/d)	89.8	36.2	46.5	40.7	63.2	276.4
Relative percentage	32%	13%	17%	15%	23%	100%

(1) Totals may not add due to rounding

For the second quarter of 2010 our production performance was led by our Eagle Ford shale and Woodford shale programs. Both our operated and partner-operated programs targeting the Eagle Ford have contributed more production than anticipated this year. The Woodford shale program in the Arkoma Basin of eastern Oklahoma has not been a focus area for us this year, however stronger than projected base production performance has benefited our 2010 production. Please refer to *Comparison of Financial Results and Trends between the three months ended June 30, 2010, and 2009* for additional discussion on production.

First Six Months 2010 Highlights

Legacy Divestiture. On February 17, 2010, we closed on a divestiture of non-core properties in Wyoming to Legacy Reserves Operating LP. Total cash received, before commission costs and Net Profits Plan payments, was $125.2 million. The final sale price is subject to normal post-closing adjustments and is expected to be finalized during the second half of 2010. The estimated gain on sale of proved properties related to the divestiture is approximately $65.1 million and may be impacted by the forthcoming post-closing adjustments mentioned above. We diverted a portion of the proceeds from this divestiture to restricted cash and will attempt to use these funds to acquire other properties in a like-kind exchange tax deferral strategy under Section 1031 of the Internal Revenue Code.

Sequel Divestiture. On March 12, 2010, we completed the divestiture of certain non-strategic properties located in North Dakota to Sequel Energy Partners, LP, Bakken Energy Partners, LLC, and Three Forks Energy Partners, LLC. Total cash received, before commission costs and Net Profits Plan payments, was $126.9 million. The final sale price is subject to normal post-closing adjustments and is expected to be finalized during the second half of 2010. The estimated gain on sale of proved properties related to the divestiture is approximately $50.4 million and may be impacted by the forthcoming post-closing adjustments mentioned above. We diverted a portion of the proceeds from this divestiture to restricted cash and will attempt to use these funds to acquire other properties in a like-kind exchange tax deferral strategy under Section 1031 of the Internal Revenue Code.

Net Profits Plan. In 2008, the Net Profits Plan was replaced with grants of performance shares and thus the 2007 Net Profits Plan pool was the last pool established by the Company. The Company will continue to make payments from the existing Net Profits Plan pools and will continue to make prospective adjustments to the long-term liability as necessary.

For the six months ended June 30, 2010, the change in the value of this liability resulted in a non-cash benefit of $33.9 million compared with a $20.8 million benefit for the same period in 2009. Current year payments made or accrued as part of allocating the proceeds received from the first half of 2010 divestitures have decreased the estimated liability for the future amounts to be paid to plan participants. This liability is a significant management estimate. 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.

Payments made from the Net Profits Plan have been expensed as compensation costs in the amounts of $13.6 million and $8.7 million for the six months ended June 30, 2010, and 2009, respectively. Additionally, the above described sales of oil and gas properties were included in a number of profit pools and resulted in payments under the Net Profits Plan of $20.1 million during the first half of 2010. These cash payments are accounted for as a reduction of net sale proceeds and impact the gain on divestiture activity in the accompanying condensed consolidated statements of operations. There were no significant cash payments made or accrued under the Net Profits Plan as a result of divestitures during the first half of 2009.

The recurring Net Profits Plan cash payments we make are dependent on actual production, realized prices, and operating and capital costs associated with the properties in each individual pool. Actual cash payments will be inherently different from the estimated liability amounts. More detailed discussion is included in Note 11 Fair Value Measurements in Part I, Item 1. An increasing percentage of the costs associated with the payments under the Net Profits Plan are now being categorized as general and administrative expense as compared to exploration expense. This is a function of the normal departure of employees who previously contributed to our exploration efforts.

The calculation of the estimated liability for the Net Profits Plan is highly sensitive to our price estimates and discount rate assumptions. For example, if we changed the commodity prices in our calculation by five percent, the liability recorded on the balance sheet at June 30, 2010, would differ by approximately $11 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 $7 million. We frequently re-evaluate the assumptions used in our calculations and consider the possible impacts stemming from the current market environment including current and future oil and gas prices, discount rates, and overall market conditions.

Production results. The table below details the regional breakdown of our first half of 2010 production.

	Mid-Continent	**ArkLaTex**	**South Texas & Gulf Coast**	**Permian**	**Rocky Mountain**	**Total (1)**
First six months of 2010 Production:						
Oil (MBbl)	107.2	40.2	317.8	884.0	1,588.5	2,937.7
Gas (MMcf)	16,247.1	6,275.2	5,795.5	2,023.4	2,902.7	33,243.9
Equivalent (MMCFE)	16,890.1	6,516.1	7,702.2	7,327.7	12,434.0	50,870.1
Avg. Daily Equivalents (MMCFE/d)	93.3	36.0	42.6	40.5	68.7	281.1
Relative percentage	33%	13%	15%	14%	25%	100%

(1) Totals may not add due to rounding

For the first half of 2010 our production has outperformed our expectations for 2010 due to stronger than anticipated production results from our South Texas & Gulf Coast and Mid-Continent regions. Please refer to the three months discussion under *Financial and production results* above and *A three-month and six-month overview of selected production and financial information, including trends* and *Comparison of Financial Results and Trends between the six months ended June 30, 2010, and 2009* for additional discussion on production.

Outlook for the Remainder of 2010

Our development program entering 2010 was focused on the drilling of oil and rich gas projects. This decision has been reinforced as natural gas prices have been under downward pressure most of this year. We continue to evaluate ways to shift capital away from natural gas drilling wherever possible, except for activities necessary to satisfy leasehold commitments or to test emerging resource plays.

We are increasing our 2010 capital investment forecast to $871 million, up from $725 million. The increase in capital reflects the success we have seen in several of our plays this year, as well as an increase in costs throughout the industry to drill and complete wells. The largest portion of the increase relates to our non-operated acreage in the Eagle Ford shale, where our operating partner has increased their rig count to six rigs and we anticipate them going to an even higher rig count by year end. This portion of the play is in an area with higher condensate yields and a richer gas stream. The increase in our partner-operated rig count accounts for over $100 million of our increased capital investment when compared to our original budget. Additionally, related to this increase in partner-operated drilling is an increase in the requirement for infrastructure on our non-operated Eagle Ford acreage. Accordingly, the revised capital expenditure forecast includes increased investments for facilities and infrastructure that will service development of this portion of our Eagle Ford shale position in the coming years.

We are adding a rig in our operated horizontal Granite Wash program where we now plan to drill seven operated wells this year, up from the four operated wells that we initially planned for the year. In the Williston Basin, recent success in our Bakken and Three Forks plays has resulted in an increase in this program s capital budget. We plan to drill several more wells with our operated rigs, and have allocated additional capital to account for increased levels of partner-operated activity in the Williston Basin. The balance of our capital program remains relatively consistent with our original budget. We have remained flexible with respect to deployment of our exploration capital. Based on early encouraging data from our Niobrara test, we have reallocated capital toward this program for later in the year and are currently looking for a rig to drill a second test well. We plan on operating two drilling rigs in the East Texas portion of our Haynesville shale position for the remainder of 2010 and we currently have two wells waiting on completion. Our activity level in the Haynesville has not changed significantly from what we planned at the beginning of the year, although our amount of capital investment was substantially reduced as a result of the carry and earning agreement we entered into in the second quarter of 2010.

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, 2010, 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, 2010	March 31, 2010	December 31, 2009	September 30, 2009
	(In millions, except production sales data)			
Production (BCFE)	25.2	25.7	26.1	26.4
Oil and gas production revenue, excluding the effects of hedging	$ 175.9	$ 212.9	$ 187.6	$ 152.7
Realized oil and gas hedge gain	$ 9.3	$ 2.6	$ 13.4	$ 28.3
Gain (loss) on divestiture activity	$ 7.0	$ 121.0	$ 22.1	$ (11.3)
Lease operating expense	$ 29.0	$ 30.0	$ 34.3	$ 34.3
Transportation costs	$ 5.1	$ 4.1	$ 5.2	$ 5.3
Production taxes	$ 11.1	$ 14.2	$ 13.3	$ 9.0
DD&A	$ 79.8	$ 77.8	$ 75.1	$ 67.0
Exploration	$ 14.5	$ 13.9	$ 13.4	$ 15.7
Impairment of proved properties	$	$	$ 21.6	$ 0.1
Abandonment and impairment of unproved properties	$ 2.4	$ 0.9	$ 25.2	$ 4.8
General and administrative	$ 25.4	$ 23.5	$ 20.7	$ 20.8
Change in Net Profits Plan liability	$ (6.6)	$ (27.3)	$ 7.0	$ 6.8
Unrealized derivative (gain) loss	$ (2.1)	$ (7.7)	$ 3.2	$ 4.1
Net income (loss)	$ 18.1	$ 126.2	$ 1.0	$ (4.4)
Percentage change from previous quarter:				
Production (BCFE)	(2)%	(2)%	(1)%	(6)%
Oil and gas production revenue, excluding the effects of hedging	(17)%	13%	23%	5%
Realized oil and gas hedge gain	258%	(81)%	(53)%	(35)%
Gain (loss) on divestiture activity	(94)%	448%	(296)%	(969)%
Lease operating expense	(3)%	(13)%	%	(4)%
Transportation costs	24%	(21)%	(2)%	15%
Production taxes	(22)%	7%	48%	(3)%
DD&A	3%	4%	12%	(5)%
Exploration	4%	4%	(15)%	(19)%
Impairment of proved properties	%	(100)%	N/M	(98)%
Abandonment and impairment of unproved properties	167%	(96)%	425%	(59)%
General and administrative	8%	14%	%	14%
Change in Net Profits Plan liability	(76)%	(490)%	3%	183%
Unrealized derivative (gain) loss	(73)%	(341)%	(22)%	(64)%
Net income (loss)	(86)%	12,520%	(123)%	(47)%

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

Selected Operations Data (In thousands, except sales price, volume, and per MCFE amounts):

	For the Three Months Ended June 30, 2010	For the Three Months Ended June 30, 2009	Percent Change Between Periods	For the Six Months Ended June 30, 2010	For the Six Months Ended June 30, 2009	Percent Change Between Periods
Net production volumes						
Oil (MBbl)	1,412	1,648	(14)%	2,938	3,288	(11)%
Natural gas (MMcf)	16,677	18,329	(9)%	33,244	36,844	(10)%
MMCFE (6:1)	25,150	28,219	*(11)%	50,870	56,573	*(10)%
Average daily production						
Oil (Bbl per day)	15,519	18,114	(14)%	16,230	18,166	(11)%
Natural gas (Mcf per day)	183,267	201,422	(9)%	183,668	203,561	(10)%
MCFE per day (6:1)	276,379	310,104	*(11)%	281,050	312,559	*(10)%
Oil & gas production revenue (1)						
Oil production revenue	$ 92,035	$ 93,487	(2)%	$ 194,184	$ 165,900	17%
Gas production revenue	93,181	95,071	(2)%	206,514	208,695	(1)%
Total	$ 185,216	$ 188,558	(2)%	$ 400,698	$ 374,595	7%
Oil & gas production expense						
Lease operating expense	$ 28,955	$ 35,602	(19)%	$ 58,984	$ 76,850	(23)%
Transportation costs	5,098	4,568	12%	9,192	10,027	(8)%
Production taxes	11,115	9,295	20%	25,332	18,417	38%
Total	$ 45,168	$ 49,465	(9)%	$ 93,508	$ 105,294	(11)%
Average net realized sales price (1)						
Oil (per Bbl)	$ 65.17	$ 56.72	15%	$ 66.10	$ 50.45	31%
Natural gas (per Mcf)	$ 5.59	$ 5.19	8%	$ 6.21	$ 5.66	10%
Per MCFE Data:						
Average net realized price (1)	$ 7.36	$ 6.68	10%	$ 7.88	$ 6.62	19%
Lease operating expenses	(1.15)	(1.26)	(9)%	(1.16)	(1.36)	(15)%
Transportation costs	(0.20)	(0.16)	25%	(0.18)	(0.18)	0%
Production taxes	(0.44)	(0.33)	33%	(0.50)	(0.33)	52%
General and administrative	(1.01)	(0.64)	58%	(0.96)	(0.61)	57%
Operating profit	$ 4.56	$ 4.29	6%	$ 5.08	$ 4.14	23%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$ 3.17	$ 2.49	27%	$ 3.10	$ 2.87	8%

(1) Includes the effects of hedging activities

(2) * Adjusting for divestitures our net production volumes from retained properties were essentially flat.

We present per MCFE information because we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe require analysis. Average daily production for the first six months of 2010 decreased ten percent to 281.1 MMCFE compared with 312.6 MMCFE for the same period in 2009, primarily driven by reduced capital spending in 2009 and recent divestitures. Adjusting for divestitures, our average daily production from retained properties for the first six months of 2010 was 275.5 MMCFE, which was relatively flat compared with 277.6 MMCFE for the same period in 2009.

Changes in production volumes, oil and gas production revenues, and costs reflect the cyclical and highly volatile nature of our industry. Our average net realized price for the three months and six months ended June 30, 2010, was $7.36 per MCFE and $7.88 per MCFE, respectively, compared with $6.68 per MCFE and $6.62 per MCFE for the respective periods of 2009. The increase in our equivalent realized price for production corresponds with stronger commodity prices in the first half of 2010 when compared with the same periods of 2009.

Our LOE for the three months and six months ended June 30, 2010, decreased $0.11 per MCFE to $1.15 per MCFE and decreased $0.20 per MCFE to $1.16 per MCFE, respectively. The divestiture of non-strategic properties with meaningfully higher operating costs is the primary reason for the decline in LOE in the comparisons above. Additionally, pricing concessions made by service providers during a period of lower industry activity in early 2009 have allowed us to keep LOE on retained properties relatively flat. We believe that the steady increase in industry activity is at a point where we will begin to see upward pressure on lease operating costs that we have not experienced the last few quarters. Production taxes for the three months and six months ended June 30, 2010, increased $0.11 per MCFE to $0.44 and increased $0.17 per MCFE to $0.50 per MCFE, respectively. Production taxes are highly correlated to pre-hedge oil and gas revenues and stronger commodity prices have impacted results for this expense item. Transportation costs for the second quarter 2010 increased $0.04 per MCFE to $0.20 per MCFE compared to the same period in 2009, which was as a result of transportation costs associated with newly drilled wells in our Eagle Ford shale program. Transportation costs for the six months ended June 30, 2010, remained flat with the comparable period of 2009 at $0.18 per MCFE. Our operating profit for the three months and six months ended June 30, 2010, was $4.56 per MCFE and $5.08 per MCFE, respectively, compared with $4.29 per MCFE and $4.14 per MCFE for the comparable periods of 2009, which was an increase of $0.27, or six percent, and $0.94, or 23 percent, respectively.

Our general and administrative expense for the three months and six months ended June 30, 2010, was $1.01 per MCFE and $0.96 per MCFE, respectively, compared with $0.64 per MCFE and 0.61 per MCFE for the comparable respective periods of 2009. 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 current short-term incentive compensation are tied to net revenues and therefore are subject to variability.

Our depletion, depreciation, and amortization, including asset retirement obligation accretion expense, for the three months and six months ended June 30, 2010, was $3.17 per MCFE and $3.10 per MCFE, respectively, compared with $2.49 per MCFE and $2.87 per MCFE for the comparable respective periods of 2009. Depreciation, depletion, and amortization was impacted by our divestiture of lower cost basis properties in the first quarter of 2010. Additionally, we have been impacted by higher early DD&A rates in the Eagle Ford, Haynesville, and Marcellus shales. We are incurring capital for infrastructure that will support future development in these plays but are limited in the amount of reserves that we can record to carry the costs, which results in higher per unit DD&A costs early in the lives of these plays. Our DD&A rate can also 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, 2010, and 2009* and *Comparison of Financial Results and Trends between the six months ended June 30, 2010 and 2009* for additional discussion on oil and gas production expense, DD&A, and general and administrative expense.

We present the following table as a summary of information relating to key indicators of financial condition and operating performance that we believe are important.

Financial Information (In thousands, except per share amounts):

	June 30, 2010	December 31, 2009	Percent Change Between Periods
Working capital deficit	$ 111,247	$ 87,625	27%
Long-term debt	$ 271,212	$ 454,902	(40)%
Stockholders equity	$ 1,182,833	$ 973,570	21%

	For the Three Months Ended June 30, 2010	2009	Percent Change Between Periods	For the Six Months Ended June 30, 2010	2009	Percent Change Between Periods
Basic net income (loss) per common share	$ 0.29	$ (0.13)	(323)%	$ 2.29	$ (1.54)	(249)%
Diluted net income (loss) per common share	$ 0.28	$ (0.13)	(315)%	$ 2.24	$ (1.54)	(245)%
Basic weighted-average shares outstanding	62,917	62,418	1%	62,855	62,377	1%
Diluted weighted-average shares outstanding	64,566	62,418	3%	64,493	62,377	3%

We account for our 3.50% Senior Convertible Notes under the treasury stock method. There is no impact on the diluted share calculation for the periods presented since our average stock price for the relevant reporting periods has not exceeded the conversion price. The 3.50% Senior Convertible Notes were issued April 4, 2007, and have not been dilutive for any reporting period since their issuance. We have in-the-money stock options, unvested RSUs, and PSAs that may be potentially dilutive securities. Both basic and diluted earnings per share are presented in the table above. A detailed explanation is presented in Note 5 Earnings per Share in Part I, Item 1 of this report.

Basic and diluted weighted-average common shares outstanding used in our June 30, 2010, and 2009, earnings per share calculations reflect increases in outstanding shares related to stock option exercises, ESPP shares issued, and the settlement of vested RSUs. We issued 148,902 and 19,570 shares of common stock during the six-month periods ended June 30, 2010, and 2009, respectively, as a result of stock option exercises. The number of RSUs that vested and settled during the first six months of 2010 and 2009 were 49,882 and 119,426, respectively.

Additional Comparative Data in Tabular Form:

	Change Between the Three Months Ended June 30, 2010, and 2009	Change Between the Six Months Ended June 30, 2010, and 2009
Increase (decrease) in oil and gas production revenues, net of hedging (In thousands)	$ (3,342)	$ 26,103
Components of revenue increases (decreases):		
Oil		
Realized price change per Bbl, including the effects of hedging	$ 8.45	$ 15.65
Realized price percentage change	15%	31%
Production change (MBbl)	(236)	(350)
Production percentage change	(14)%	(11)%
Natural Gas		
Realized price change per Mcf, including the effects of hedging	$ 0.40	$ 0.55
Realized price percentage change	8%	10%
Production change (MMcf)	(1,652)	(3,600)
Production percentage change	(9)%	(10)%

Production mix as a percentage of total oil and gas revenue, including impact of hedging, and production:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
Revenue				
Oil	50%	50%	48%	44%
Natural gas	50%	50%	52%	56%
Production				
Oil	34%	35%	35%	35%
Natural gas	66%	65%	65%	65%

Information regarding the effects of oil, natural gas and natural gas liquids hedging activity:

	For the Three Months Ended June 30, 2010	For the Three Months Ended June 30, 2009	For the Six Months Ended June 30, 2010	For the Six Months Ended June 30, 2009
Oil Hedging				
Percentage of oil production hedged	54%	47%	54%	48%
Oil volumes hedged (MBbl)	767	782	1,573	1,569
Increase (decrease) in oil revenue	$ (8.1) million	$ 4.6 million	$ (16.9) million	$ 20.6 million
Average realized oil price per Bbl before hedging	$ 70.92	$ 53.96	$ 71.86	$ 44.21
Average realized oil price per Bbl after hedging	$ 65.17	$ 56.72	$ 66.10	$ 50.45
Natural Gas Hedging				
Percentage of gas production hedged (includes NGLs)	47%	49%	49%	49%
Natural gas volumes hedged (in MMBtu, includes NGLs)	8.8 million	9.6 million	18.2 million	19.0 million
Increase in gas revenue (includes effects of NGL hedges)	$ 17.4 million	$ 38.7 million	$ 28.8 million	$ 78.3 million
Average realized gas price per Mcf before hedging (includes NGLs)	$ 4.54	$ 3.07	$ 5.34	$ 3.54
Average realized gas price per Mcf after hedging (includes NGLs)	$ 5.59	$ 5.19	$ 6.21	$ 5.66

Information regarding the components of exploration expense:

	For the Three Months Ended June 30, 2010	2009	For the Six Months Ended June 30, 2010	2009
	(In millions)			
Summary of Exploration Expense				
Geological and geophysical expenses	$ 5.2	$ 6.3	$ 8.8	$ 10.7
Exploratory dry hole expense	0.2	4.6	0.4	4.7
Overhead and other expenses	9.1	8.6	19.2	17.7
Total	$ 14.5	$ 19.5	$ 28.4	$ 33.1

Comparison of Financial Results and Trends between the three months ended June 30, 2010, and 2009

Oil and gas production revenue. Average daily production decreased 11 percent to 276.4 MMCFE for the quarter ended June 30, 2010, compared with 310.1 MMCFE for the quarter ended June 30, 2009. The following table presents the regional changes in our production and oil and gas revenues and costs between the two quarters.

	Average Net Daily Production Added (Decreased) (MMCFE/d)	Pre-Hedge Oil and Gas Revenue Added (Decreased) (In millions)	Production Costs Increase (Decrease) (In millions)
Mid-Continent	(14.8)	4.2	1.7
ArkLaTex	(7.3)	1.8	(1.3)
South Texas & Gulf Coast	20.6	19.1	3.6
Permian	(3.9)	7.7	(1.1)
Rocky Mountain	(28.3)	(2.2)	(7.2)
Total	(33.7)	30.6	(4.3)

The largest regional decrease occurred in the Rocky Mountain region as a result of the loss of production related to the divestiture of non-strategic oil and gas assets that occurred in the fourth quarter of 2009 and first quarter of 2010. Production in the Mid-Continent region decreased as a result of shut-in wells and natural production declines in our Constitution Field. Production in the ArkLaTex decreased as a result of natural production decline and decreased capital investment in 2009 and 2010. The only production growth occurred in the South Texas & Gulf Coast region as a result of production from drilling activity in our Eagle Ford shale program by ourselves and our partner. We anticipate sequential increases in production during the third and fourth quarters of 2010.

The following table summarizes the average realized prices we received in the second quarter of 2010 and 2009, before the effects of hedging. Prices for oil and gas increased between the two periods.

	For the Three Months Ended June 30, 2010	2009

Realized oil price ($/Bbl)	$	70.92	$	53.96
Realized gas price ($/Mcf)	$	4.54	$	3.07
Realized equivalent price ($/MCFE)	$	6.99	$	5.15

The combination of a 36 percent increase in average realized prices offset by an 11 percent decrease in production volumes between periods still resulted in higher oil and gas revenue. We expect our realized price to trend with commodity prices.

Realized oil and gas hedge gain. We recorded a net realized hedge gain of $9.3 million for the three-month period ended June 30, 2010, related to settlements on oil and gas hedges, compared with $43.3 million gain for the same period in 2009, as a result of an increase in commodity prices on a quarter-to-quarter basis. We expect our realized oil and gas hedge gains and losses to trend with commodity prices.

Gain on divestiture activity. We had a $7.0 million net gain on divestiture activity for the quarter ended June 30, 2010, compared with a $1.2 million net gain on sale for the comparable period of 2009, due to the divestiture of non-core oil and gas properties located in our South Texas & Gulf Coast region and sales of acreage in our Permian and Rocky Mountain regions that occurred in the second quarter of 2010. We expect to continue to evaluate potential divestitures of non-strategic properties in future periods.

Marketed gas system revenue and expense. Marketed gas system revenue increased $2.2 million to $16.4 million for the quarter ended June 30, 2010, compared with $14.2 million for the comparable period of 2009. Concurrent with the increase in marketed gas system revenue, marketed gas system expense increased $2.2 million to $15.8 million for the quarter ended June 30, 2010, compared with $13.6 million for the comparable period of 2009. The net margin has 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 net realized price.

Oil and gas production expense. Total production costs decreased $4.3 million, or nine percent, to $45.2 million for the second quarter of 2010 from $49.5 million in the comparable period of 2009. Total oil and gas production costs per MCFE increased $0.04 to $1.79 for the second quarter of 2010, compared with $1.75 for the same period in 2009. This increase is comprised of the following:

- An $0.11 per MCFE increase in production taxes is due to the increase in pre-hedge oil and gas revenues between periods, particularly in the South Texas & Gulf Coast and Mid-Continent regions

- A $0.04 increase in overall transportation cost on a per MCFE basis was as a result of transportation costs associated with newly drilled wells in our Eagle Ford shale program

- A $0.01 overall increase in workover LOE on a per MCFE basis relating to an increase in workover activity in the Rocky Mountain region associated with legacy oil production and workover in our Mid-Continent region at our Constitution Field

- A $0.12 decrease in recurring LOE on a per MCFE basis reflects the sale of non-core properties with higher per unit LOE costs in the first quarter of 2010 resulting in lower LOE on a per unit basis quarter over quarter. Additionally, reductions in pricing offered by service providers as a result of the decrease in activity across the exploration and production sector in early 2009 allowed for LOE on retained properties to be held relatively flat. Activity in the sector has increased in recent months, particularly in areas with oil projects. We expect the various resources required to service our industry will become more sought after and harder to secure as a result of this increase in activity. We expect to see upward pressure on LOE throughout the remainder of the year.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A increased $9.4 million or 13 percent to $79.8 million for the three-month period ended June 30, 2010, compared with $70.4 million for the same period in 2009. The current year s DD&A per MCFE was higher when compared with the same period in 2009 due to the impact of our divestiture of lower cost basis properties in the first quarter of 2010 and production related to properties developed in a higher cost environment becoming a larger percentage of our production mix. Additionally, we have been impacted by higher DD&A rates in the Eagle Ford, Haynesville, and Marcellus shales. We are incurring capital for infrastructure that will support future development in these plays but are limited in the amount of reserves that we can book to carry the costs, which results in higher per unit DD&A costs early in the lives of these plays. Any future proved property impairments, divestitures, and changes in underlying proved reserve volumes will continue to impact our DD&A expense.

Exploration. Exploration expense decreased $5.0 million, or 26 percent, to $14.5 million for the three-month period ended June 30, 2010, compared with $19.5 million for the same period in 2009. We recorded $4.6 million of exploratory dry hole expense in the second quarter of 2009 that related to wells in the ArkLaTex. There were no significant exploratory dry hole costs in the second quarter of 2010. We continue to focus on our exploratory program for our current resource plays and expect to maintain a modest program for new areas of exploration in future periods. Any exploratory well incapable of producing oil or natural gas in commercial quantities will be deemed an exploratory dry hole, which will impact the amount of exploration expense we record.

Impairment of proved properties. There were no proved property impairments recorded in the second quarter of 2010. We recognized $6.0 million for impairment of proved properties in the second quarter of 2009 related principally to impairments of properties in the Gulf of Mexico in which we relinquished our ownership interests. We generally expect proved property impairments to occur in periods of low commodity prices.

Abandonment and impairment of unproved properties. Abandonment and impairment of unproved properties decreased $9.2 million, or 80 percent, to $2.4 million for the three months ended June 30, 2010, compared with $11.6 million for the comparable period in 2009. In 2009 we had write-offs related to our Floyd shale acreage located in Mississippi, as well as non-core acreage in Oklahoma. We generally expect 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.

General and administrative. General and administrative expense increased $7.2 million or 40 percent to $25.4 million for the three months ended June 30, 2010, compared with $18.2 million for the comparable period of 2009. On a per unit basis, G&A expense increased $0.37 to $1.01 per MCFE for the second quarter of 2010 compared to $0.64 per MCFE for the same three-month period in 2009.

General and administrative expense increased due to a $3.7 million increase in base compensation, cash bonus, and long-term incentive compensation expense for the three months ended June 30, 2010, compared with the same period in 2009, a $1.5 million decrease in COPAS overhead reimbursements

caused by a decrease in our operated well count resulting from our recent divestiture efforts, and an $800,000 increase in cash payments accrued under the Net Profits Plan.

The increase in Net Profits Plan payments to plan participants was the result of higher commodity prices, pools entering the higher 20 percent payout level as described further in Note 7 of Part 1, Item 1of this report, and the 2005 pool entering payout for the first time. As of the end of the second quarter of 2010, 18 of our 21 pools are in payout status. No additional pools are expected to reach payout in 2010. We expect payments made under the Net Profits Plan to continue to trend with commodity prices. The increase in cash bonus and long-term incentive compensation expense reflects the improvement in our performance and the anticipated achievement of various performance criteria, approved by our Compensation Committee, as well as compensation expense associated with PSAs granted in the third quarter of 2009.

Change in Net Profits Plan liability. For the quarter ended June 30, 2010, this non-cash item was a benefit of $6.6 million compared to expense of $2.4 million for the same period in 2009. We saw a reduction in the Net Profits Plan liability as a result of a decrease in expected future cash flows thereby reducing the future liability for amounts to be paid to plan participants. We generally expect the change in this liability to trend with commodity prices.

Unrealized derivative (gain) loss. We recognized a gain of $2.1 million in the second quarter of 2010 compared to a loss of $11.3 million for the same period in 2009. This non-cash item is driven by the change in the value of our hedge position, as well as the portion of that position that is considered ineffective for accounting purposes. Please refer to our discussion under the heading *Hedging Activities* under Overview of the Company, Highlights, and Outlook.

Other expense. Other expense decreased $5.2 million to $578,000 for the quarter ended June 30, 2010, compared with $5.8 million for the same period in 2009. In the second quarter of 2009, we incurred an additional loss related to hurricanes of $5.0 million, which related to a decrease in our estimate of insurance reimbursements related to the Vermillion 281 platform that was lost in Hurricane Ike.

Income tax expense. We recorded income tax expense of $12.4 million for the second quarter of 2010 compared to income tax benefit of $5.1 million for the second quarter of 2009 resulting in effective tax rates of 40.8 percent and 38.0 percent, respectively. The change in income tax expense is primarily the result of the differences in components of net income discussed above. The 2010 increase in effective tax rate from 2009 primarily reflects changes in the mix of the highest marginal state tax rates and the resulting effect on year-to-date net income as a result of divestiture and drilling activity in 2010, and to a lesser extent, changes in the effects of other permanent differences including the domestic production activities deduction. The current portion of our income tax expense resulted in a nominal benefit in the second quarter of 2010 versus an expense in the second quarter of 2009 due to the impact of our drilling program from utilization of proceeds from non-core asset divestitures in 2010 and to a decreased drilling program in 2009 caused by lower commodity prices. These trends are expected to continue throughout the remainder of 2010 based upon our current projected capital expenditures program and commodity price outlook.

Comparison of Financial Results and Trends between the six months ended June 30, 2010, and 2009

Oil and gas production revenue. Average daily production decreased ten percent to 281.1 MMCFE for the six months ended June 30, 2010, compared with 312.6 MMCFE for the same period in 2009. The following table presents the regional changes in our production and oil and gas revenues and costs between the two six-month periods.

	Average Net Daily Production Added (Decreased) (MMCFE/d)	**Pre-Hedge Oil and Gas Revenue Added (In millions)**	**Production Costs Increase (Decrease) (In millions)**
Mid-Continent	(9.7)	21.9	2.0
ArkLaTex	(9.6)	2.7	(4.4)
South Texas & Gulf Coast	15.8	36.7	5.9
Permian	(4.3)	27.0	(0.6)
Rocky Mountain	(23.7)	24.8	(14.7)
Total	(31.5)	113.1	(11.8)

The largest regional decrease occurred in the Rocky Mountain region and was partially offset by the only regional increase in the South Texas & Gulf Coast region which is described in more detail above under *Comparison of Financial Results and Trends between the three months ended June 30, 2010, and 2009*.

The following table summarizes the average realized prices we received for the first six months of 2010 compared to the same period in 2009, before the effects of hedging. Prices for oil and gas increased between the two periods.

	For the Six Months Ended June 30,			
	2010		2009	
Realized oil price ($/Bbl)	$	71.86	$	44.21
Realized gas price ($/Mcf)	$	5.34	$	3.54
Realized equivalent price ($/MCFE)	$	7.64	$	4.87

The combination of a 57 percent increase in average realized prices offset by a ten percent decrease in production volumes between periods still resulted in higher oil and gas revenue. Please refer to additional discussion under *Comparison of Financial Results and Trends between the three months ended June 30, 2010, and 2009.*

Realized oil and gas hedge gain. We recorded a net realized hedge gain of $11.9 million for the six-month period ended June 30, 2010, related to settlements on oil and gas hedges, compared with $98.9 million gain for the same period in 2009, as a result of an increase in commodity prices on a period-to-period comparison.

Gain on divestiture activity. We had a $128.0 million net gain on divestiture activity for the six-month period ended June 30, 2010, compared with a $645,000 net gain on sale for the comparable period of 2009, due primarily to the divestiture of non-core oil and gas properties located in our Rocky Mountain region that occurred in the first quarter of 2010. The final gain on sale of proved properties will be adjusted for normal post-closing adjustments and is expected to be finalized during the second half of 2010. We expect to continue to evaluate potential divestitures of non-strategic properties in future periods.

Marketed gas system revenue and expense. Marketed gas system revenue increased $10.6 million to $38.2 million for the six-month period ended June 30, 2010, compared with $27.6 million for the comparable period of 2009. Concurrent with the increase in marketed gas system revenue, marketed gas system expense increased $10.9 million to $37.9 million for the six-month period ended June 30, 2010, compared with $27.0 million for the comparable period in 2009.

Oil and gas production expense. Total production costs decreased $11.8 million, or 11 percent, to $93.5 million for the first six months of 2010 from $105.3 million in the comparable period of 2009. Total oil and gas production costs per MCFE decreased $0.03 to $1.84 for the first six months of 2010, compared with $1.87 for the same period in 2009. This decrease is comprised of the following:

- A $0.24 decrease in recurring LOE on a per MCFE basis reflects the divestiture of higher cost non-core properties in the first half of 2010. Please refer to additional discussion under *Comparison of Financial Results and Trends between the three months ended June 30, 2010, and 2009.*

- A $0.17 per MCFE increase in production taxes is due to the increase in pre-hedge oil and gas revenues between periods

- A $0.04 overall increase in workover LOE on a per MCFE basis relating to an increase in workover activity in the Rocky Mountain region due to our shift toward oil-weighted projects

- Overall transportation on a per MCFE basis was essentially flat from period to period.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A decreased $4.6 million, or three percent, to $157.5 million for the six-month period ended June 30, 2010, compared with $162.1 million for the same period in 2009. DD&A expense per MCFE increased eight percent to $3.10 for the six-month period ended June 30, 2010, compared to $2.87 for the same period in 2009. Please refer to additional discussion under *Comparison of Financial Results and Trends between the three months ended June 30, 2010, and 2009.*

Exploration. Exploration expense decreased $4.7 million, or 14 percent, to $28.4 million for the six-month period ended June 30, 2010, compared with $33.1 million for the same period in 2009. Please refer to additional discussion under *Comparison of Financial Results and Trends between the three months ended June 30, 2010, and 2009.*

Impairment of proved properties. There were no proved property impairments recorded for the six-month period ended June 30, 2010. We recorded a $153.1 million impairment of proved oil and gas properties for the comparable period in 2009, which was driven by a significant decrease in realized gas prices in the first quarter of 2009, particularly in the Mid-Continent region, and for our coalbed methane project at Hanging Woman Basin, which was divested of in late 2009.

Abandonment and impairment of unproved properties. Abandonment and impairment of unproved properties decreased $12.2 million or 79 percent to $3.3 million for the six months ended June 30, 2010, compared with $15.5 million for the comparable period in 2009. Please refer to additional discussion under *Comparison of Financial Results and Trends between the three months ended June 30, 2010, and 2009.*

Impairment of materials inventory. There were no materials inventory impairments recorded for the six-month period ended June 30, 2010. We recorded an $11.3 million impairment of materials inventory for the six-month period ended June 30, 2009, which was caused by a decrease in the value of tubular goods and other raw materials.

General and administrative. General and administrative expense increased $14.3 million or 41 percent to $48.9 million for the six months ended June 30, 2010, compared with $34.6 million for the comparable period of 2009. On a per unit basis, G&A expense increased $0.35 to $0.96 per MCFE for the first six months of 2010 compared to $0.61 per MCFE for the same six-month period in 2009.

General and administrative expense increased due to a $4.5 million increase in cash payments accrued under the Net Profits Plan, a $4.9 million increase in cash bonus and long-term incentive compensation expense, and a $1.8 million increase in compensation for the six months ended June 30, 2010, compared with the same period in 2009. Please refer to additional discussion under *Comparison of Financial Results and Trends between the three months ended June 30, 2010, and 2009.*

Change in Net Profits Plan liability. Please refer to discussion under the heading *Net Profits Plan* under Overview of the Company, Highlights, and Outlook.

Unrealized derivative (gain) loss. We recognized a gain of $9.8 million for the six months ended June 30, 2010, compared to a loss of $13.1 million for the same period in 2009. This non-cash item is driven by the change in the value of our hedge position, as well as the portion of that position that is considered ineffective for accounting purposes. Please refer to our discussion under the heading *Hedging Activities* under

Overview of the Company, Highlights, and Outlook.

Other expense. Other expense decreased $10.0 million to $1.5 million for the six months ended June 30, 2010, compared with $11.5 million for the same period in 2009. In the first quarter of 2009, we incurred $2.6 million of expense related to the assignment of a drilling rig contract in our Rocky Mountain region. We also incurred an additional loss related to hurricanes of $7.1 million for the six months ended June 30, 2009, which related to an increase in our estimate of the remediation cost for the Vermilion 281 platform that was lost in Hurricane Ike.

Income tax expense. Income tax expense totaled $87.3 million for the six-month period of 2010 compared to an income tax benefit of $59.0 million for the same period of 2009 resulting in effective tax rates of 37.7 percent and 38.1 percent, respectively. The change in income tax expense is the result of the 2010 divestitures and the Company s 2009 loss before income taxes. The 2010 decrease in effective tax rate from 2009 reflects changes in 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 2010 compared to 2009 due to the impact of our non-core asset divestitures in 2010 and the status of our capital expenditures drilling program at June 30, 2010.

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

Based on our current outlook, we expect our generated cash flow from operations in 2010, including the net cash proceeds from the Rocky Mountain oil and other non-core asset divestiture packages, to fund the majority of our exploration and development budget for 2010. We intend to rely on our credit facility to fund the remaining balance of our capital program for the year. Accordingly, we do not expect to access the capital markets in 2010. We anticipate we will continue to periodically 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, sales of non-core properties, and accessing the capital 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 that provide capital. All of these sources can be impacted by the general condition of the broad economy and by significant fluctuations in oil and gas prices, operating costs, and volumes produced, all of which affect us and our industry. We have no control over the market prices for oil and natural gas, although we are able to influence the amount of our net realized revenues related to our oil and gas sales through the use of derivative contracts. The borrowing base on our credit facility could be reduced as a result of lower commodity prices or sales of non-core producing properties. Historically, decreases in commodity prices have limited our industry s access to the capital markets. We believe the public debt markets are currently accessible. Equity and convertible debt issuances are also available to us as alternative financing sources. We do not anticipate the need to raise public debt or equity financing in the near term, however these are options we would consider under the appropriate circumstances.

Current Credit Facility

On April 14, 2009, we entered into an amended $1.0 billion senior secured revolving credit facility with twelve participating banks. The initial borrowing base was set at $900 million. On March 17, 2010, the lending group redetermined our reserve-backed borrowing base under the credit facility at $900 million. We have been provided a $678 million commitment amount by the bank group. The new amended credit facility agreement has a maturity date of July 31, 2012. Management believes that the current commitment is sufficient for our current liquidity needs. To date, we have experienced no issues drawing upon our credit facility. No individual bank participating in the credit facility represents more than 16 percent of the lending commitments under the credit facility. We monitor the credit environment closely and have frequent discussions with the lending group.

As of July 28, 2010, we had $677.5 million of available borrowing capacity under this facility. We have a single letter of credit outstanding under our credit facility, in the amount of $483,000 as of

July 28, 2010, which reduces the amount available under the commitment amount on a dollar-for-dollar basis. Borrowings under the facility are secured by mortgages on the majority of our oil and gas properties. Please refer to Note 5 Long-term Debt in Part IV, Item 15 of our Annual Report on Form 10-K for the year ended December 31, 2009, for our borrowing base utilization grid.

Our weighted-average interest rate for the three-month periods ended June 30, 2010, and 2009, was 9.4 percent and 5.5 percent, respectively. Our weighted-average interest rate for the six-month periods ended June 30, 2010, and 2009, was 8.1 percent and 4.9 percent, respectively. 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, letter of credit fees, amortization of the convertible notes debt discount, and amortization of deferred financing costs. The increase in our weighted-average interest rate from the comparative quarter in 2009 is the result of lower cash interest expense and non-cash charges being spread across a much lower average outstanding debt balance.

We are subject to customary financial and non-financial 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, and amortization of not more than 3.5 to 1.0 and also include a current ratio as defined by our credit agreement of not less than 1.0 to 1.0. As of June 30, 2010, our debt to EBITDA ratio and current ratio as defined by our credit agreement were 0.64 and 3.03, 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. In the first six months of 2010 we spent $304.6 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 available borrowing capacity under our revolving credit facility.

Expenditures for exploration and development of oil and gas properties and acquisitions are the primary use of our capital resources. We expect our capital and exploration expenditures in 2010 will exceed our operating cash flow, and we plan to fund this shortfall with the proceeds received from our non-core asset divestitures that closed during the first quarter of 2010 and borrowings under our credit facility. 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. Also, the impact of oil and gas prices on investment opportunities, the availability of capital and borrowing facilities, and the success of our development and exploratory activities could lead to changes in funding requirements for future development. We regularly review our capital expenditure budget to assess changes in current and projected cash flows, acquisition and divestiture 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 existing bank credit facility agreement, compliance with securities laws, and the terms and provisions of our stock repurchase program. There have been no share repurchases to date in 2010, and we do not plan to repurchase shares for the remainder of 2010.

Current proposals to fund the federal 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 potential funding reductions in conjunction with a tight credit environment could have a significant adverse effect on drilling in the United States for a number of years.

The following table presents amount and percentage changes in cash flows between the six-month periods ended June 30, 2010, and 2009. 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, 2010	2009	Change	Percent Change
	(In thousands)			
Net cash provided by operating activities	$ 270,150	$ 241,761	$ 28,389	12%
Net cash used in investing activities	$ 82,716	$ 199,389	$ (116,673)	(59)%
Net cash used in financing activities	$ 187,834	$ 38,114	$ 149,720	393%

Analysis of Cash Flow Changes Between the Six Months Ended June 30, 2010, and June 30, 2009

Operating activities. Cash received from oil and gas production revenue, net of the realized effects of hedging, increased $4.7 million to $403.6 million for the first six months of 2010, compared with $398.9 million for the first six months of 2009. Additionally, cash paid for lease operating expenses decreased $14.0 million to $63.7 million for the first six months of 2010, compared with $77.7 million for the first six months of 2009.

Investing activities. Cash used in investing activities for the six months ended June 30, 2010, was $82.7 million compared with $199.4 million of cash used for investing activities in the comparable period of 2009. We received $248.0 million from the sale of non-core properties primarily in the Rocky Mountain region for the six months ended June 30, 2010. In conjunction with the sale of non-core properties, we had a net $19.6 million deposit to restricted cash for the six months ended June 30, 2010. There were no major divestitures for the same period in 2009. Cash outflows for capital expenditures increased by $88.8 million for the six months ended June 30, 2010, compared with the same period in 2009. This is due to increased drilling activity as a result of more favorable commodity prices and an improved overall macro-economic environment.

Financing activities. Net repayments on our credit facility increased by $163.0 million for the six months ended June 30, 2010, compared with the same period in 2009. We reduced our credit facility balance to zero in the first quarter of 2010, and although it remains at zero at the end of the second quarter, we expect it to gradually increase during the rest of 2010.

Capital Expenditures

The following table sets forth certain historical information regarding the costs incurred by us in our oil and gas activities.

	For the Six Months Ended June 30,	
	2010	2009
	(In thousands)	
Development costs (1)	$ 92,820	$ 127,624
Exploration costs	212,385	38,730
Acquisitions		
Proved properties		51
Unproved properties - other	30,832	19,864
Total, including asset retirement obligations (2)	$ 336,037	$ 186,269

(1) Includes capitalized interest of $1.2 million in 2010 and $1.0 million in 2009.

(2) Includes amounts relating to estimated asset retirement obligations of $486,000 in 2010 and $506,000 in 2009.

Costs incurred for development and exploration activities during the first six months of 2010 increased $138.9 million or 83 percent compared to the same period in 2009. This increase in capital and exploration activities reflects a stable and improving economic environment and higher cash flows provided by operating activities and divestiture proceeds.

We believe our operating cash flows together with the full availability of our credit facility will be sufficient to fund our planned operating, drilling, and acquisition expenditures for the foreseeable future. The amount and allocation of future capital and exploration expenditures will depend upon a number of factors, including the number and size of available economic acquisition and drilling opportunities, our cash flows from operating and financing activities, and our ability to assimilate leasehold and producing property acquisitions. In addition, the impact of oil and natural gas 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.

Commodity Price Risk and Interest Rate Risk

We are exposed to market risk, including the effects of changes in oil and gas 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, 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, 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 Annual Report on Form 10-K for the year ended December 31, 2009.

Summary of Oil and Gas Production Hedges in Place

Our oil and natural gas 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.

Our net realized oil and gas prices are impacted by hedges we have placed on future forecasted production. Hedging is an important part of our financial risk management program. The amount of production we hedge is driven by the amount of debt on our consolidated balance sheet and the level of capital and long-term commitments we have made. In the case of a significant acquisition of producing properties, we will consider hedging a portion of the anticipated production in order to protect the economics assumed at the time of the acquisition. As of June 30, 2010, our hedged positions of anticipated production through the first quarter of 2013 totaled approximately 5 million Bbls of oil, 46 million MMBtu of natural gas, and 2 million Bbls of natural gas liquids. As of July 28, 2010, we have hedge contracts in place through the second quarter 2013 for a total of approximately 6 million Bbls of anticipated crude oil production, 50 million MMBtu of anticipated natural gas production, and 2 million Bbls of anticipated natural gas liquids production.

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 contracted ceiling price and the index price if the index price is above the contracted ceiling price. No amounts are paid or received if the index price is between the contracted floor and ceiling prices.

The following tables describe the volumes, average contract prices, and fair values of contracts we have in place as of June 30, 2010, and July 28, 2010. The Company seeks to minimize ineffectiveness by entering into oil derivative contracts indexed to NYMEX WTI, natural gas derivative contracts indexed to regional index prices associated with pipelines in proximity to the Company s areas of production, and NGL derivative contracts indexed to Oil Price Information Service Mont Belvieu. As the Company s derivative contracts contain the same index as the Company s sales contracts, this results in derivative contracts that are highly correlated with the underlying hedged item.

Oil Contracts

Oil Swaps

Contract Period	NYMEX WTI Volumes (Bbls)	Weighted-Average Contract Price (per Bbl)	Fair Value at June 30, 2010 Asset (Liability) (in thousands)
Third quarter 2010	393,000	$ 68.77	$ (2,944)
Fourth quarter 2010	309,000	$ 66.06	(3,521)
2011	1,164,000	$ 67.06	(14,093)
2012	1,051,400	$ 82.19	1,066
All oil swap	2,917,400		$ (19,492)

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, 2010 Asset (Liability) (in thousands)
Third quarter 2010	344,500	$ 50.00	$ 64.91	$ (4,129)
Fourth quarter 2010	344,500	$ 50.00	$ 64.91	(4,959)
2011	1,236,000	$ 50.00	$ 63.70	(22,434)
2012	163,700	$ 80.00	$ 100.85	959
2013	282,600	$ 80.00	$ 100.85	1,472
All oil collars	2,371,300			$ (29,091)

Gas Contracts

Gas Swaps

Contract Period	Volumes (MMBtu)		Weighted-Average Contract Price (per MMBtu)		Fair Value at June 30, 2010 Asset (in thousands)
Third quarter 2010					
IF ANR OK	70,000	$	5.64	$	95
IF CIG	240,000	$	5.38		334
IF EL PASO	370,000	$	6.33		741
IF HSC	1,350,000	$	8.03		4,656
IF NGPL	500,000	$	5.43		563
IF NNG VENTURA	360,000	$	5.89		520
IF PEPL	230,000	$	5.56		310
IF RELIANT	1,190,000	$	5.37		1,169
IF TETCO STX	230,000	$	5.81		304
NYMEX Henry Hub	960,000	$	6.94		2,180
Fourth quarter 2010					
IF ANR OK	140,000	$	5.97		191
IF CIG	270,000	$	5.87		390
IF EL PASO	370,000	$	6.43		713
IF HSC	590,000	$	8.61		2,246
IF NGPL	430,000	$	5.61		429
IF NNG VENTURA	360,000	$	6.34		558
IF PEPL	520,000	$	5.92		702
IF RELIANT	1,350,000	$	5.71		1,481
IF TETCO STX	180,000	$	6.23		268
NYMEX Henry Hub	840,000	$	7.52		2,118

Gas swaps (continued)

Contract Period	Volumes (MMBtu)	Weighted-Average Contract Price (per MMBtu)	Fair Value at June 30, 2010 Asset (in thousands)
2011			
IF ANR OK	500,000	$ 6.10	528
IF CIG	1,030,000	$ 5.96	1,102
IF EL PASO	1,780,000	$ 6.35	2,403
IF HSC	360,000	$ 9.01	1,356
IF NGPL	1,040,000	$ 6.09	1,085
IF NNG VENTURA	1,200,000	$ 6.36	1,395
IF PEPL	1,830,000	$ 6.04	1,941
IF RELIANT	4,510,000	$ 6.13	5,013
IF TETCO STX	1,420,000	$ 6.51	1,958
NYMEX Henry Hub	2,130,000	$ 6.72	2,995
2012			
IF ANR OK	360,000	$ 6.18	314
IF CIG	1,020,000	$ 5.77	528
IF EL PASO	850,000	$ 6.04	539
IF NGPL	660,000	$ 6.34	644
IF NNG VENTURA	620,000	$ 6.51	548
IF PEPL	2,730,000	$ 6.25	2,574
IF RELIANT	2,440,000	$ 6.22	2,015
IF TETCO STX	660,000	$ 6.30	505
All gas swap contracts	35,690,000		$ 47,411

Gas Collars

Contract Period	Volumes (MMBtu)	Weighted-Average Floor Price (per MMBtu)	Weighted-Average Ceiling Price (per MMBtu)	Fair Value at June 30, 2010 Asset (in thousands)
Third quarter 2010				
IF CIG	510,000	$ 4.85	$ 7.08	$ 460
IF HSC	150,000	$ 5.57	$ 7.88	159
IF PEPL	1,240,000	$ 5.31	$ 7.61	1,301
NYMEX Henry Hub	60,000	$ 6.00	$ 8.38	79
Fourth quarter 2010				
IF CIG	510,000	$ 4.85	$ 7.08	385
IF HSC	150,000	$ 5.57	$ 7.88	153
IF PEPL	1,240,000	$ 5.31	$ 7.61	1,198
NYMEX Henry Hub	60,000	$ 6.00	$ 8.38	73
2011				
IF CIG	1,800,000	$ 5.00	$ 6.32	850
IF HSC	480,000	$ 5.57	$ 6.77	316
IF PEPL	4,225,000	$ 5.31	$ 6.51	2,576
NYMEX Henry Hub	120,000	$ 6.00	$ 7.25	108
All gas collars	10,545,000			$ 7,658

Natural Gas Liquid Contracts

Natural Gas Liquid Swaps

	Volumes (approx. Bbls)	Weighted-Average Contract Price (per Bbl)	Fair Value at June 30, 2010 Asset (in thousands)
Third quarter 2010	221,000	$ 45.34	$ 1,148
Fourth quarter 2010	205,000	$ 45.36	941
2011	714,000	$ 44.07	2,773
2012	492,000	$ 44.25	2,033
2013	84,000	$ 44.95	320
All natural gas liquid swaps*	1,716,000		$ 7,215

*Natural gas liquid swaps are comprised of OPIS Mont. Belvieu TET Propane (34%), OPIS Mont. Belvieu Purity Ethane (33%), OPIS Mont. Belvieu NON-TET Isobutane (6%), OPIS Mont. Belvieu NON-TET Natural Gasoline (14%), and OPIS Mont. Belvieu NON-TET Normal Butane (13%).

Hedge Contracts Entered into After June 30, 2010

The following table includes all hedges entered into subsequent to June 30, 2010 through July 28, 2010.

Oil Swaps

Contract Period	NYMEX WTI Volumes (Bbl)		Weighted-Average Contract Price (Per Bbl)
2012	462,800	$	83.60
2013	294,600	$	84.30
All oil swaps	757,400		

Natural Gas Swaps

Contract Period	Volumes (MMBtu)		Weighted-Average Contract Price (Per MMBtu)
2012			
IF RELIANT	1,100,000	$	5.40
2013			
IF PEPL	1,250,000	$	5.65
IF RELIANT	1,290,000	$	5.64
All natural gas swaps	3,640,000		

Natural Gas Liquid Swaps

Contract Period	Volumes (Bbls)		Weighted-Average Contract Price (per Bbl)
Fourth Quarter 2010	80,000	$	28.91
2011	193,000	$	23.19

All natural gas liquids swaps*	273,000

*Natural gas liquid swaps are comprised of OPIS Mont. Belvieu TET Propane (8%), OPIS Mont. Belvieu Purity Ethane (84%), OPIS Mont. Belvieu NON-TET Isobutane (1%), OPIS Mont. Belvieu NON-TET Natural Gasoline (5%), and OPIS Mont. Belvieu NON-TET Normal Butane (2%).

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

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. We had no floating-rate debt outstanding as of June 30, 2010. Our fixed-rate debt outstanding, net of debt discount, at this same date was $271.2 million.

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, 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, 2010, we have not been involved in any unconsolidated SPE transactions.

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

Critical Accounting Policies and Estimates

We refer you to the corresponding section in Part II, Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2009, and to the footnote disclosures included in Part I, Item 1 of this report.

New Accounting Pronouncements

Please see Note 12 Recent Accounting Pronouncements under Part I, Item 1 of this report for new accounting matters.

Environmental

SM Energy s compliance with applicable environmental 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 regulations and do not currently anticipate that material future expenditures will be required under the existing regulatory framework. However, 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.

The U.S. Congress is currently considering legislation that would amend the Safe Drinking Water Act to eliminate an existing exemption from federal regulation of hydraulic fracturing activities. Hydraulic fracturing is a common and reliable process in our industry of creating artificial cracks, or fractures, in deep underground rock formations through the pressurized injection of water, sand and other additives to enable oil or natural gas to move more easily through the rock pores to a production well. This process is often necessary to produce commercial quantities of oil and natural gas from many reservoirs, especially shale rock formations. We routinely utilize hydraulic fracturing in many of our reservoirs, and our Eagle Ford, Haynesville, Marcellus, Woodford, and other shale programs utilize or contemplate the utilization of hydraulic fracturing. Currently, regulation of hydraulic fracturing is primarily conducted at the state level through permitting and other compliance requirements. If adopted, the proposed amendment to the Safe Drinking Water Act could result in additional regulations and permitting requirements at the federal level. On March 18, 2010, the Environmental Protection Agency (EPA) announced that it has allocated $1.9 million in 2010 and has requested funding in fiscal year 2011 for conducting a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health. In addition, various state and local governments are considering increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions, and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas, such as watersheds. Additional regulations and permitting requirements could lead to significant operational delays and increased operating costs, could make it more difficult to perform hydraulic fracturing, and could impair our ability to produce commercial quantities of oil and natural gas from certain reservoirs.

In December 2009, the EPA published its findings that emissions of carbon dioxide, which is a byproduct of the burning of refined oil products and natural gas, methane, which is a primary component of natural gas, and other greenhouse gases present an endangerment to human 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. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Accordingly, the EPA had proposed regulations that would require a reduction in emissions of greenhouse gases from motor vehicles and that could also lead to the imposition of greenhouse gas emission limitations in Clean Air Act permits for certain stationary sources. In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. On March 23, 2010, the EPA announced a proposed rulemaking that would expand its final rule on reporting of greenhouse gas emissions to include owners and operators of onshore oil and natural gas production. If the proposed rule is finalized in its current form, monitoring of those newly covered sources would commence on January 1, 2011. On May 13, 2010, the EPA issued rules to regulate greenhouse gas emissions from large stationary sources such as power plants and oil refineries. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur increased costs to reduce emissions of greenhouse gases associated with our operations and could adversely affect demand for the oil and natural gas that we produce.

In addition, in June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009 (ACESA), which would establish an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. ACESA would require a 17% reduction in greenhouse gas emissions from 2005 levels by 2020, and just over an 80% reduction of such emissions by 2050. Under this legislation, the EPA would issue a capped and steadily declining number of tradable emissions allowances to certain major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases into the atmosphere. The cost of these allowances would be expected to escalate significantly over time. The net effect of ACESA would be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas. The U.S. Senate has begun work on its own legislation for restricting domestic greenhouse gas emissions, and the Obama administration has indicated its support of legislation to reduce greenhouse gas emissions through an emission allowance system. In addition, several states have considered initiatives to regulate emissions of greenhouse gases, primarily through the planned development of greenhouse gas emissions inventories and/or regional greenhouse gas cap and trade programs. Although it is not possible at this time to predict when the U.S. Senate may act on climate change legislation or how any bill passed by the Senate would be reconciled with ACESA, any future federal or state laws or regulations that may be adopted to address greenhouse gas emissions could require us to incur increased operating costs and could adversely affect the demand for the oil and natural gas that we produce. Additional information about the potential effect of climate change issues on our business is presented under the Climate Change caption in the Management s Discussion and Analysis of Financial Condition and Results of Operations section of our Annual Report on Form 10-K for the year ended December 31, 2009.

In response to the widely reported recent oil spill in the Gulf of Mexico resulting from a deepwater drilling rig explosion in April 2010, the U.S. Congress is considering a number of legislative proposals relating to the upstream oil and gas industry both onshore and offshore that could result in significant additional laws or regulations affecting our operations, including a proposal to raise or eliminate the cap on liability for oil spill cleanups under the Oil Pollution Act of 1990.

Although it is not possible at this time to predict whether proposed legislation or regulations will be adopted as initially written, if at all, or how legislation or new regulations that may be adopted would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions. Additional costs or operating restrictions associated with legislation or regulations could have a material adverse effect on our operating results and cash flows, in addition to the demand for the crude oil, natural gas, and other hydrocarbon products that we produce.

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*
- *Proved reserve estimates and the estimates of both future net revenues and the present value of future net revenues that are included in their calculation*
- *Future oil and natural gas production estimates*
- *Our outlook on future oil and natural gas prices 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*
- *Other similar matters such as those discussed in the Management s Discussion and Analysis of Financial Condition and Results of Operations section of this Form 10-Q.*

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 2009 Annual Report on Form 10-K and include such factors as:

- *The volatility and level of realized oil and natural gas prices*

- *A contraction in demand for oil and natural gas as a result of adverse general economic conditions or climate change initiatives*

- *The availability of economically attractive exploration, development, and property acquisition opportunities and any necessary financing, including constraints on the availability of opportunities and financing due to distressed capital and credit market conditions*

- *Our ability to replace reserves and sustain production*

- *Unexpected drilling conditions and results*

- *Unsuccessful exploration and development drilling*

- *The risks of hedging strategies, including the possibility of realizing lower prices on oil and natural gas sales as a result of commodity price risk management activities*

- *The pending nature of reported divestiture plans for certain non-core oil and gas properties as well as the ability to complete divestiture transactions*

- *The uncertain nature of the expected benefits from acquisitions and divestitures of oil and natural gas properties, including uncertainties in evaluating oil and natural gas reserves of acquired properties and associated potential liabilities, and uncertainties with respect to the amount of proceeds that may be received from divestitures*

- *The imprecise nature of oil and natural gas reserve estimates*

- *Uncertainties inherent in projecting future rates of production from drilling activities and acquisitions*

- *Declines in the values of our oil and natural gas properties resulting in impairment charges and write-downs*

- *The ability of purchasers of production to pay for amounts purchased*

- *Drilling and operating service availability*

- *Uncertainties in cash flow*

- *The financial strength of hedge contract counterparties and credit facility participants, and the risk that one or more of these parties may not satisfy their contractual commitments*

- *The negative impact that lower oil and natural gas prices could have on our ability to borrow and fund capital expenditures*

- *The potential effects of increased levels of debt financing*

- *Our ability to compete effectively against other independent and major oil and natural gas companies and*

- *Litigation, environmental matters, the potential impact of government regulations, and the use of management estimates.*

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.

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 and Gas Production Hedges 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 disclosure.

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 the 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 1A. RISK FACTORS

There have been no material changes from the risk factors as previously disclosed in our Form 10-K for the year ended December 31, 2009, in response to Item 1A of Part I of such Form 10-K.

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

(c) The following table provides information about purchases by the Company or any affiliated purchaser (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the fiscal quarter ended June 30, 2010, of shares of the Company s common stock, which is the sole class of equity securities registered by the Company pursuant to Section 12 of the Exchange Act.

PURCHASES OF EQUITY SECURITIES BY ISSUER

AND AFFILIATED PURCHASERS

Period	**(a) Total Number of Shares Purchased (1)**	**(b) Average Price Paid per Share**	**(c) Total Number of Shares Purchased as Part of Publicly Announced Program**	**(d) Maximum Number of Shares that May Yet Be Purchased Under the Program (2)**
04/01/10 04/30/10	339	$ 39.99		3,072,184
05/01/10 05/31/10	88	$ 43.24		3,072,184
06/01/10 06/30/10		$		3,072,184
Total:	427	$ 40.47		3,072,184

(1) Includes 427 shares withheld (under the terms of grants under the Equity Incentive Compensation Plan) to offset tax withholding obligations that occur upon the delivery of outstanding shares underlying restricted stock units.

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

The payment of dividends and stock repurchases are subject to covenants in our bank credit facility, including the requirement that we maintain certain levels of stockholders equity and the limitation that does not allow our annual dividend rate to exceed $0.25 per share.

ITEM 6. EXHIBITS

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

Exhibit	**Description**
3.1*	Restated Certificate of Incorporation of SM Energy Company, as amended through June 1, 2010,
3.2	Certificate of Amendment of Restated Certificate of Incorporation effective June 1, 2010 (filed as Exhibit 3.1 to the registrant s Current Report on Form 8-K filed on June 2, 2010, and incorporated herein by reference.)
3.3	Restated By-Laws of SM Energy Company amended effective as of June 1, 2010 (filed as Exhibit 3.2 to the registrant s Current Report on Form 8-K filed on June 2, 2010, and incorporated herein by reference)
10.1	Equity Incentive Compensation Plan As Amended and Restated as of April 1, 2010 (filed as Exhibit 10.1 to the registrant s Current Report on Form 8-K filed on June 2, 2010, and incorporated herein by reference)
10.2*	Carry and Earning Agreement between St. Mary Land & Exploration Company and Encana Oil & Gas (USA) Inc. executed as of April 29, 2010
10.3*	SM Energy Company Form of Performance Share and Restricted Stock Unit Award Agreement as of July 1, 2010
10.4*	SM Energy Company Form of Performance Share and Restricted Stock Unit Award Notice as of July 1, 2010
10.5*	SM Energy Company Form of Non-Employee Director Restricted Stock Award Agreement as of May 27, 2010
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
99.1*	Audit Committee Pre-Approval of Non-Audit Services
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

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* Filed with this report.

** Furnished with this report.

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

Exhibit constitutes a management contract or compensatory plan or agreement.

SIGNATURES

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

	SM ENERGY COMPANY	
August 3, 2010	By:	/s/ ANTHONY J. BEST Anthony J. Best President and Chief Executive Officer
August 3, 2010	By:	/s/ A. WADE PURSELL A. Wade Pursell Executive Vice President and Chief Financial Officer
August 3, 2010	By:	/s/ MARK T. SOLOMON Mark T. Solomon Controller