RANGE RESOURCES CORP
Form 10-Q
July 27, 2010

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

FORM 10-Q

(Mark one)

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

For the quarterly period ended June 30, 2010

OR

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

For the transition period from __________ to __________

Commission File Number: 001-12209

RANGE RESOURCES CORPORATION
(Exact Name of Registrant as Specified in Its Charter)

Delaware	**34-1312571**
(State or Other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification No.)
100 Throckmorton Street, Suite 1200 **Fort Worth, Texas**	**76102**
(Address of Principal Executive Offices)	(Zip Code)

Registrant s telephone number, including area code
(817) 870-2601

Former Name, Former Address and Former Fiscal Year, if changed since last report: Not applicable

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for shorter period that the registrant was required to submit and post such files).

Yes þ No o

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

Large Accelerated Filer þ	Accelerated Filer o	Non-Accelerated Filer o (Do not check if smaller reporting company)	Smaller Reporting Company o

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

160,029,859 Common Shares were outstanding on July 22, 2010.

RANGE RESOURCES CORPORATION
FORM 10-Q
Quarter Ended June 30, 2010

Unless the context otherwise indicates, all references in this report to Range, we, us, or our are to Range Resources Corporation and its wholly-owned subsidiaries and its ownership interests in equity method investees.

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PART I FINANCIAL INFORMATION
ITEM 1. Financial Statements

RANGE RESOURCES CORPORATION
CONSOLIDATED BALANCE SHEETS
(In thousands, except per share data)

	June 30, 2010 (Unaudited)	December 31, 2009
Assets		
Current assets:		
Cash and equivalents	$ 166,858	$ 767
Accounts receivable, less allowance for doubtful accounts of $1,409 and $2,176	101,299	123,622
Deferred tax asset		8,054
Unrealized derivative gain	83,864	21,545
Inventory and other	21,391	21,292
Total current assets	373,412	175,280
Unrealized derivative gain	26,032	4,107
Equity method investments	150,748	146,809
Oil and gas properties, successful efforts method	6,522,267	6,308,707
Accumulated depletion and depreciation	(1,466,754)	(1,409,888)
	5,055,513	4,898,819
Transportation and field assets	135,727	161,034
Accumulated depreciation and amortization	(54,920)	(69,199)
	80,807	91,835
Other assets	76,333	79,031
Total assets	$ 5,762,845	$ 5,395,881
Liabilities		
Current liabilities:		
Accounts payable	$ 254,405	$ 214,548
Asset retirement obligations	2,446	2,446
Accrued liabilities	60,274	58,585
Deferred tax liability	7,952	
Accrued interest	23,763	24,037
Unrealized derivative loss	2,781	14,488
Total current liabilities	351,621	314,104
Bank debt	475,000	324,000

Subordinated notes	1,384,562	1,383,833
Deferred tax liability	839,245	776,965
Unrealized derivative loss		271
Deferred compensation liability	113,247	135,541
Asset retirement obligations and other liabilities	72,331	82,578
Commitments and contingencies		
Stockholders Equity		
Preferred stock, $1 par, 10,000,000 shares authorized, none issued and outstanding		
Common stock, $0.01 par, 475,000,000 shares authorized, 160,007,428 issued at June 30, 2010 and 158,336,264 issued at December 31, 2009	1,600	1,583
Common stock held in treasury, 210,972 shares at June 30, 2010 and 217,327 shares at December 31, 2009	(7,741)	(7,964)
Additional paid-in capital	1,809,966	1,772,020
Retained earnings	680,392	606,529
Accumulated other comprehensive income	42,622	6,421
Total stockholders equity	2,526,839	2,378,589
Total liabilities and stockholders equity	$ 5,762,845	$ 5,395,881

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

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RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited, in thousands, except per share data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Revenues				
Oil and gas sales	$ 206,784	$ 192,523	$ 443,544	$ 395,712
Transportation and gathering	674	2,152	2,767	1,647
Derivative fair value income (loss)	6,546	(9,856)	48,879	65,691
Gain (loss) on the sale of assets	10,176	(29)	79,044	7
Other	637	(4,358)	(938)	(6,188)
Total revenues	224,817	180,432	573,296	456,869
Costs and expenses				
Direct operating	29,775	34,828	60,815	70,369
Production and ad valorem taxes	8,090	7,564	16,160	15,821
Exploration	14,473	11,368	29,108	24,707
Abandonment and impairment of unproved properties	13,497	40,954	25,904	60,526
General and administrative	35,836	29,103	64,006	54,013
Termination costs			7,938	
Deferred compensation plan	(14,135)	756	(19,847)	13,190
Interest expense	30,779	29,555	61,066	56,184
Depletion, depreciation and amortization	90,997	88,713	179,623	173,033
Impairment of proved properties			6,505	
Total costs and expenses	209,312	242,841	431,278	467,843
Income (loss) from operations	15,505	(62,409)	142,018	(10,974)
Income tax expense (benefit)				
Current		619		619
Deferred	6,453	(23,145)	55,387	(4,318)
Total income tax expense (benefit)	6,453	(22,526)	55,387	(3,699)
Net income (loss)	$ 9,052	$ (39,883)	$ 86,631	$ (7,275)
Income (loss) per common share:				
Basic	$ 0.06	$ (0.26)	$ 0.54	$ (0.05)
Diluted	$ 0.06	$ (0.26)	$ 0.54	$ (0.05)

Dividends per common share	$ 0.04	$ 0.04	$ 0.08	$ 0.08
Weighted average common shares outstanding:				
Basic	156,820	154,389	156,608	154,056
Diluted	158,472	154,389	158,601	154,056

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

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RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited, in thousands)

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Operating activities:		
Net income (loss)	$ 86,631	$ (7,275)
Adjustments to reconcile net cash provided from operating activities:		
Loss from equity method investments	985	5,526
Deferred income tax expense (benefit)	55,387	(4,318)
Depletion, depreciation, amortization and proved property impairment	186,129	173,033
Exploration dry hole costs		131
Mark-to-market (gain) loss on oil and gas derivatives not designated as hedges	(42,169)	30,070
Abandonment and impairment of unproved properties	25,904	60,526
Unrealized derivative (gain) loss	(11)	97
Deferred and stock-based compensation	5,866	32,794
Amortization of deferred financing costs and other	2,367	2,333
(Gain) loss on sale of assets and other	(79,044)	1,943
Changes in working capital:		
Accounts receivable	15,392	46,453
Inventory and other	338	(2,154)
Accounts payable	13,859	(72,008)
Accrued liabilities and other	(11,197)	1,283
Net cash provided from operating activities	260,437	268,434
Investing activities:		
Additions to oil and gas properties	(349,406)	(275,999)
Additions to field service assets	(10,270)	(14,849)
Acreage and proved property purchases	(187,192)	(107,321)
Additions to equity method investment		(6,400)
Other assets	(45)	9,079
Proceeds from disposal of assets	318,632	182,122
Purchase of marketable securities held by the deferred compensation plan	(14,553)	(3,605)
Proceeds from the sales of marketable securities held by the deferred compensation plan	13,296	1,981
Net cash used in investing activities	(229,538)	(214,992)
Financing activities:		
Borrowing on credit facilities	371,000	451,000
Repayment on credit facilities	(220,000)	(741,000)
Dividends paid	(12,768)	(12,541)
Issuance of common stock	5,785	6,002
Issuance of subordinated notes		285,201
Debt issuance costs		(6,161)

Change in cash overdrafts	(13,385)	(38,212)
Proceeds from the sales of common stock held by the deferred compensation plan	4,560	3,683
Purchases of common stock held by the deferred compensation plan		(15)
Net cash provided from (used in) financing activities	135,192	(52,043)
Increase in cash and equivalents	166,091	1,399
Cash and equivalents at beginning of period	767	753
Cash and equivalents at end of period	$ 166,858	$ 2,152

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

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RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Unaudited, in thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
Net income (loss)	$ 9,052	$ (39,883)	$ 86,631	$ (7,275)
Other comprehensive (loss) income:				
Realized (gain) loss on hedge derivative contract settlements reclassified into earnings from other comprehensive income, net of taxes	(11,371)	(33,488)	(12,124)	(65,822)
Change in unrealized deferred hedging gains (losses), net of taxes	(4,257)	(3,000)	48,325	43,183
Total comprehensive income (loss)	$ (6,576)	$ (76,371)	$ 122,832	$ (29,914)

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

RANGE RESOURCES CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

(1) ORGANIZATION AND NATURE OF BUSINESS

We are engaged in the exploration, development and acquisition of oil and gas properties primarily in the Southwestern and the Appalachian regions of the United States. We seek to increase our reserves and production primarily through drilling and complementary acquisitions. Range Resources Corporation is a Delaware corporation with our common stock listed and traded on the New York Stock Exchange under the symbol RRC.

(2) BASIS OF PRESENTATION

These interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Range Resources 2009 Annual Report on Form 10-K filed on February 24, 2010. These consolidated financial statements are unaudited but, in the opinion of management, reflect all adjustments necessary for fair presentation of the results for the periods presented. All adjustments are of a normal recurring nature unless disclosed otherwise. These consolidated financial statements, including selected notes, have been prepared in accordance with the applicable rules of the Securities and Exchange Commission (SEC) and do not include all of the information and disclosures required by accounting principles generally accepted in the United States of America for complete financial statements.

(3) NEW ACCOUNTING STANDARDS

Recently Adopted

Accounting standards for variable interest entities were amended by the Financial Accounting Standards Board (the FASB) in June 2009. The new accounting standards replace the existing quantitative-based risks and rewards calculation for determining which enterprise has a controlling financial interest in a variable interest entity with an approach focused on identifying which enterprise has the power to direct the activities of a variable interest entity. In addition, the concept of qualifying special-purpose entities has been eliminated. Ongoing assessments of whether an enterprise is the primary beneficiary of a variable interest entity are also required. The amended accounting standard for variable interest entities requires reconsideration for determining whether an entity is a variable interest entity when changes in facts and circumstances occur such that the holders of the equity investment at risk, as a group, lack the power from voting rights or similar rights to direct the activities of the entity. Enhanced disclosures are required for any enterprise that holds a variable interest in a variable interest entity. The adoption of this guidance did not have an impact on our consolidated results of operations, financial position or cash flows.

A standard to improve disclosures about fair value measurements was issued by the FASB in January 2010. The additional disclosures required include: (1) the different classes of assets and liabilities measured at fair value, (2) the significant inputs and techniques used to measure Level 2 and Level 3 assets and liabilities for both recurring and nonrecurring fair value measurements, (3) the gross presentation of purchases, sales, issuances and settlements for the rollforward of Level 3 activity, and (4) the transfers in and out of Levels 1 and 2. We adopted all aspects of this standard in the first quarter 2010. This adoption did not have a significant impact on our consolidated results of operations, financial position or cash flows. See Note 12 for our disclosures about fair value measurements.

In February 2010, the FASB amended guidance on subsequent events to alleviate potential conflicts between FASB guidance and SEC requirements. Under this amended guidance, SEC filers are no longer required to disclose the date through which subsequent events have been evaluated in originally issued and revised financial statements. This guidance was effective immediately and we adopted these new requirements in the first quarter 2010. The adoption of this guidance did not have an impact on our financial statements.

(4) DISPOSITIONS AND ACQUISITIONS

2010 Asset Sales

In February 2010, we entered into an agreement to sell our tight gas sand properties in Ohio. We closed approximately 90% of the sale in March 2010 and closed the remainder in June 2010. Total proceeds received were approximately $323.0 million and we recorded a gain of $77.4 million. The agreement has an effective date of January 1, 2010, and consequently operating net revenues after January 1, 2010 are downward adjustments to the selling price. The asset sale is subject to typical post-closing adjustments. The proceeds we received were placed in a like-kind exchange account and are reflected in Cash and equivalents on our June 30, 2010 consolidated balance sheet.

In June 2010, we used a portion of the proceeds to purchase proved and unproved gas properties in Virginia.

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2009 Asset Sales

In fourth quarter 2009, we sold natural gas properties in New York for proceeds of $36.3 million. The proceeds were credited to oil and gas properties, with no gain or loss recognized, as the sale did not materially impact the depletion rate of the remaining properties in the amortization base.

In second quarter 2009, we sold oil properties located in West Texas for proceeds of $182.0 million. The proceeds were credited to oil and gas properties, with no gain or loss recognized, as the sale did not materially impact the depletion rate of the remaining properties in the amortization base.

2010 Acquisitions

In June 2010, we purchased proved and unproved natural gas properties in Virginia for approximately $135.0 million. After recording asset retirement obligations, the purchase price allocated to proved property was $132.9 million and unproved property was $2.6 million. The purchase price allocation is preliminary and subject to revision pending finalization of closing adjustments. We used proceeds from our like-kind exchange account to fund this acquisition (see 2010 Asset Sales above).

(5) INCOME TAXES

Income tax expense (benefit) was as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Income tax expense (benefit)	$6,453	$(22,526)	$55,387	$(3,699)
Effective tax rate	41.6%	36.1%	39.0%	33.7%

We compute our quarterly taxes under the effective tax rate method based on applying an anticipated annual effective rate to our year-to-date income, except for discrete items. Income taxes for discrete items are computed and recorded in the period that the specific transaction occurs. For the three months ended June 30, 2010 and 2009, our overall effective tax rate on pre-tax income from operations was different than the statutory rate of 35% due primarily to state income taxes, valuation allowances and other permanent differences. For the six months ended June 30, 2010 and 2009, our overall effective tax rate on pre-tax income from operations was different than the statutory rate of 35% due primarily to state income taxes, valuation allowances and other permanent differences.

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(6) EARNINGS PER COMMON SHARE

Basic net income (loss) per share attributable to common shareholders is computed as (i) net income (loss) (ii) less income allocable to participating securities (iii) divided by weighted average basic shares outstanding. Diluted net income (loss) per share attributable to common shareholders is computed as (i) basic net income (loss) attributable to common shareholders (ii) plus diluted adjustments to income allocable to participating securities divided by weighted average diluted shares outstanding. The following table sets forth a reconciliation of net income (loss) to basic net income (loss) attributable to common shareholders and to diluted net income (loss) attributable to common shareholders and a reconciliation of basic weighted average common shares outstanding to diluted weighted average common shares outstanding (in thousands except per share amounts):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Numerator:				
Net income (loss)	$ 9,052	$ (39,883)	$ 86,631	$ (7,275)
Less: Basic income allocable to participating securities [(a)]	(159)		(1,491)	
Basic net income (loss) attributable to common shareholders	8,893	(39,883)	85,140	(7,275)
Diluted adjustments to income allocable to participating securities [(a)]			16	
Diluted net income (loss) attributable to common shareholders	$ 8,893	$ (39,883)	$ 85,156	$ (7,275)
Denominator:				
Weighted average common shares outstanding basic	156,820	154,389	156,608	154,056
Effect of dilutive securities:				
Employee stock options, SARs and stock held in the deferred compensation plan	1,652		1,993	
Weighted average common shares diluted	158,472	154,389	158,601	154,056
Income per common share:				
Basic net income	$ 0.06	$ (0.26)	$ 0.54	$ (0.05)
Diluted net income	$ 0.06	$ (0.26)	$ 0.54	$ (0.05)

(a) Restricted stock awards represent participating securities because they participate in nonforfeitable dividends or distributions with common equity owners. Income allocable to participating securities represents the distributed and undistributed earnings attributable to the participating securities. Restricted stock awards do not participate in undistributed net losses.

The weighted average common shares basic amount for the three months ended June 30, 2010 excludes 2.8 million shares of restricted stock at June 30, 2010 and 2.6 million shares of restricted stock at June 30, 2009 held in our deferred compensation plans (although all restricted stock is issued and outstanding upon grant). Weighted average common shares basic for the six months ended June 30, 2010 excludes 2.7 million of shares of restricted stock compared to 2.4 million for the six months ended June 30, 2009. Stock appreciation rights of 1.1 million shares for the three months ended June 30, 2010 were outstanding but not included in the computations of diluted net income per share because the grant prices of the SARs were greater than the average market price of the common shares and would be anti-dilutive to the computations. For the six months ended June 2010, the per share calculations above exclude 1.1 million stock appreciation rights that were anti-dilutive. Due to our net loss from operations for the three months and the six months ended June 30, 2009, we excluded all outstanding stock options, stock appreciation rights and restricted stock from the computations of diluted net income per share because the effect would have been anti-dilutive.

(7) SUSPENDED EXPLORATORY WELL COSTS

The following table reflects the changes in capitalized exploratory well costs for the six months ended June 30, 2010 and the year ended December 31, 2009 (in thousands):

	June 30, 2010	December 31, 2009
Beginning balance at January 1	$ 19,052	$ 47,623
Additions to capitalized exploratory well costs pending the determination of proved reserves	12,774	26,216
Reclassifications to wells, facilities and equipment based on determination of proved reserves	(3,593)	(52,849)
Capitalized exploratory well costs charged to expense		(1,938)
Balance at end of period	28,233	19,052
Less exploratory well costs that have been capitalized for a period of one year or less	(17,018)	(10,778)
Capitalized exploratory well costs that have been capitalized for a period greater than one year	$ 11,215	$ 8,274
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	5	6

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The $28.2 million of capitalized exploratory well costs at June 30, 2010 was incurred in 2010 ($12.1 million), in 2009 ($8.4 million) and in 2008 ($7.7 million). Of the five projects that have exploratory costs capitalized for more than one year, all are Marcellus Shale wells and are waiting on the completion of pipelines.

(8) INDEBTEDNESS

We had the following debt outstanding as of the dates shown below (in thousands) (bank debt interest rate at June 30, 2010 is shown parenthetically). No interest expense was capitalized during the three months or the six months ended June 30, 2010 and 2009.

	June 30, 2010	December 31, 2009
Bank debt (2.2%)	$ 475,000	$ 324,000
Subordinated debt:		
7.375% Senior Subordinated Notes due 2013, net of discount	198,570	198,362
6.375% Senior Subordinated Notes due 2015	150,000	150,000
7.5% Senior Subordinated Notes due 2016, net of discount	249,660	249,637
7.5% Senior Subordinated Notes due 2017	250,000	250,000
7.25% Senior Subordinated Notes due 2018	250,000	250,000
8.0% Senior Subordinated Notes due 2019, net of discount	286,332	285,834
Total debt	$ 1,859,562	$ 1,707,833

Bank Debt

In October 2006, we entered into an amended and restated revolving bank facility, which we refer to as our bank debt or our bank credit facility, which is secured by substantially all of our assets. The bank credit facility provides for an initial commitment equal to the lesser of the facility amount or the borrowing base. On June 30, 2010, the borrowing base was $1.5 billion and our facility amount was $1.25 billion. The bank credit facility provides for a borrowing base subject to redeterminations semi-annually and for event-driven unscheduled redeterminations. As part of our semi-annual bank review completed March 31, 2010, our borrowing base was reaffirmed at $1.5 billion and our facility amount was also reaffirmed at $1.25 billion. Our current bank group is comprised of twenty-six commercial banks each holding between 2.4% and 5.0% of the total facility. The facility amount may be increased up to the borrowing base amount with twenty days notice, subject to payment of a mutually acceptable commitment fee to those banks agreeing to participate in the facility amount increase. At June 30, 2010, the outstanding balance under the bank credit facility was $475.0 million and we had $100,000 of undrawn letters of credit leaving $774.9 million of borrowing capacity available under the facility amount. The loan matures October 2012. Borrowing under the bank credit facility can either be the Alternate Base Rate (as defined) plus a spread ranging from 0.875% to 1.625% or LIBOR borrowings at the adjusted LIBOR Rate (as defined) plus a spread ranging from 1.75% to 2.5%. The applicable spread is dependent upon borrowings relative to the borrowing base. We may elect, from time to time, to convert all or any part of our LIBOR loans to base rate loans or to convert all or any part of the base rate loans to LIBOR loans. The weighted average interest rate on the bank credit facility was 2.2% for the three months ended June 30, 2010 compared to 2.5% for the three months ended June 30, 2009. The weighted average interest rate on the bank credit facility was 2.2% for the six months ended June 30, 2010 compared to 2.6% for the six months ended June 30, 2009. A commitment fee is paid on the undrawn balance based on an annual rate of between 0.375% and 0.50%. At June 30, 2010, the commitment fee was 0.375% and the interest rate margin was 1.75% on our LIBOR loans and 0.875% on our base rate loans. At July 22, 2010, the interest rate (including applicable margin) was 2.3%.

Senior Subordinated Notes

In May 2009, we issued $300.0 million aggregate principal amount of 8.0% senior subordinated notes due 2019 (8.0% Notes). The 8.0% Notes were issued at a discount, which is being amortized over the life of the 8.0% Notes. Interest on the 8.0% Notes is payable semi-annually, in May and November, and is guaranteed by certain of our subsidiaries. We may redeem the 8.0% Notes, in whole or in part, at any time on or after May 15, 2014, at redemption prices of 104.0% of the principal amount as of May 15, 2014 declining to 100.0% on May 15, 2017 and thereafter. Before May 15, 2012, we may redeem up to 35% of the original aggregate principal amount of the 8.0% Notes at a redemption price equal to 108.0% of the principal amount thereof, plus accrued and unpaid interest, if any, with the proceeds of certain equity offerings, provided that at least 65% of the original aggregate principal amount of the 8.0% Notes remain outstanding immediately after the occurrence of such redemption and also provided such redemption shall occur within 60 days of the date of the closing of the equity offering.

Debt Covenants

Our bank credit facility contains negative covenants that limit our ability, among other things, to pay cash dividends, incur additional indebtedness, sell assets, enter into certain hedging contracts, change the nature of our business or operations, merge, consolidate, or make investments. In addition, we are required to maintain a ratio of debt to EBITDAX (as defined in the credit agreement) of no greater than 4.0 to 1.0 and a current ratio (as defined in the credit agreement) of no less than 1.0 to 1.0. We were in compliance with our covenants under the bank credit facility at June 30, 2010.

The indentures governing our senior subordinated notes contain various restrictive covenants that are substantially identical to each other and may limit our ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, enter into transactions with affiliates or change the nature of our business. At June 30, 2010, we were in compliance with these covenants.

(9) ASSET RETIREMENT OBLIGATIONS

Our asset retirement obligations primarily represent the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives. Significant inputs used in determining such obligations include estimates of plugging and abandonment costs, estimated future inflation rates and well life. A reconciliation of our liability for plugging, abandonment and remediation costs for the six months ended June 30, 2010 is as follows (in thousands):

	Six Months Ended June 30, 2010
Beginning of period	$ 78,812
Liabilities incurred	869
Acquisitions	556
Liabilities settled	(1,058)
Liabilities sold	(12,891)
Accretion expense	2,818
Change in estimate	
End of period	$ 69,106

Accretion expense is recognized as a component of Depreciation, depletion and amortization expense on our consolidated statement of operations.

(10) CAPITAL STOCK

We have authorized capital stock of 485 million shares, which includes 475 million shares of common stock and 10 million shares of preferred stock. The following is a summary of changes in the number of common shares outstanding since the beginning of 2009:

	Six Months Ended June 30, 2010	Year Ended December 31, 2009
Beginning balance	158,118,937	155,375,487
Shares issued in lieu of cash bonuses		184,926
Stock options/SARs exercised	892,166	1,384,861
Restricted stock grants	398,769	413,353
Treasury shares	6,355	16,573
Shares issued for acreage purchases	380,229	743,737

Ending balance	159,796,456	158,118,937

Treasury Stock

The Board of Directors has approved up to $10.0 million of repurchases of common stock based on market conditions and opportunities. During 2008, we repurchased 78,400 shares of common stock at an average price of $41.11 for a total of $3.2 million. We have $6.8 million remaining under this authorization.

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(11) DERIVATIVE ACTIVITIES

We use commodity-based derivative contracts to manage exposures to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. Historically, our derivative activities have consisted of collars and fixed price swaps. We do not utilize complex derivatives such as swaptions, knockouts or extendable swaps. We typically utilize commodity swap and collar contracts to (1) reduce the effect of price volatility of the commodities we produce and sell and (2) support our annual capital budget and expenditure plans. At June 30, 2010, we had collars covering 152.9 Bcf of gas at weighted average floor and cap prices of $5.66 to $6.98 per mcf and 2.1 million barrels of oil at weighted average floor and cap prices of $70.44 to $90.33 per barrel. The fair value of these collars, represented by the estimated amount that would be realized upon termination, based on a comparison of the contract prices and a reference price, generally New York Mercantile Exchange (NYMEX), on June 30, 2010, was a net unrealized pre-tax gain of $111.9 million. These contracts expire monthly through December 2011. We currently have not entered into any NGL derivative contracts.

The following table sets forth our derivative volumes and average hedge prices as of June 30, 2010:

Period	Contract Type	Volume Hedged	Average Hedge Price
Natural Gas			
2010	Collars	325,000 Mmbtu/day	$ 5.55-$7.20
2011	Collars	255,000 Mmbtu/day	$ 5.73-$6.83
Crude Oil			
2010	Collars	1,000 bbls/day	$75.00-$93.75
2011	Collars	5,244 bbls/day	$70.00-$90.00

Every derivative instrument is recorded on the balance sheet as either an asset or a liability measured at its fair value. Fair value is generally determined based on the difference between the fixed contract price and the underlying estimated market price at the determination date. Changes in the fair value of derivatives that qualify for hedge accounting are recorded as a component of accumulated other comprehensive income (AOCI) on our consolidated balance sheet, which is later transferred to oil and gas sales when the underlying physical transaction occurs and the hedging contract is settled. Amounts included in AOCI at June 30, 2010 and December 31, 2009 relate solely to our derivative activities. As of June 30, 2010, an unrealized pre-tax derivative gain of $68.6 million was recorded in AOCI. This gain is expected to be reclassified into earnings as a $26.4 million gain in 2010 and as a $42.2 million gain in 2011. The actual reclassification to earnings will be based on market prices at the contract settlement date.

For those derivative instruments that qualify for hedge accounting, settled transaction gains and losses are determined monthly, and are included as increases or decreases to oil and gas sales in the period the hedged production is sold. Oil and gas sales include $18.3 million of gains in the three months ended June 30, 2010 compared to gains of $53.2 million in the same period of 2009 related to settled hedging transactions. Oil and gas sales include $19.6 million of gains in the six months ended June 30, 2010 compared to gains of $104.5 million in the six months ended June 30, 2009 related to settled hedging transactions. Any ineffectiveness associated with these hedge derivatives is reflected in Derivative fair value income (loss) on our consolidated statement of operations. The ineffective portion is calculated as the difference between the change in fair value of the derivative and the estimated change in future cash flows from the item hedged. The six months ended June 30, 2010 includes ineffective losses (unrealized and realized) of $341,000 compared to gains of $1.5 million in the same period of 2009.

Through June 2010, we have elected to designate our commodity derivative instruments that qualify for hedge accounting as cash flow hedges. To designate a derivative as a cash flow hedge, we document at the hedge s inception our assessment that the derivative will be highly effective in offsetting expected changes in cash flows from the item hedged. This assessment, which is updated at least quarterly, is generally based on the most recent relevant historical correlation between the derivative and the item hedged. The ineffective portion of the hedge is calculated as the difference between the change in fair value of the derivative and the estimated change in cash flows from the item hedged. If, during the derivative s term, we determine the hedge is no longer highly effective, hedge accounting is prospectively discontinued and any remaining unrealized gains or losses, based on the effective portion of the derivative at that date, are reclassified to earnings as oil or gas sales when the underlying transaction occurs. If it is determined that the designated hedge transaction is not probable to occur, any unrealized gains or losses are recognized immediately as Derivative fair value income (loss) on our consolidated statement of operations. During the first six months of 2010, there were no gains or losses recorded due to the discontinuance of hedge accounting treatment for these derivatives. During the first six months of 2009, there were gains of

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$5.4 million reclassified into earnings as a result of the discontinuance of hedge accounting treatment for some of our derivatives due to asset sales.

Some of our derivatives do not qualify for hedge accounting or are not designated as a hedge but provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and gas production. These contracts are accounted for using the mark-to-market accounting method. We recognize all unrealized and realized gains and losses related to these contracts as Derivative fair value income (loss) on our consolidated statement of operations (for additional information see table below).

In addition to the collars discussed above, we have entered into basis swap agreements, which do not qualify for hedge accounting and are marked to market. The price we receive for our gas production can be more or less than the NYMEX price because of adjustments for delivery location (basis), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively fix a portion of our basis adjustments. The fair value of the basis swaps was a net unrealized pre-tax loss of $4.8 million at June 30, 2010 and expire through the first quarter of 2011.

Derivative Fair Value Income (Loss)

The following table presents information about the components of derivative fair value income (loss) in the three months and the six months ended June 30, 2010 and 2009 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Hedge ineffectiveness realized	$ 5	$ 1,081	$ (352)	$ 1,578
unrealized	260	356	11	(97)
Change in fair value of derivatives that do not qualify for hedge accounting[(a)]	(4,409)	(61,595)	42,169	(30,070)
Realized gain on settlements gas[(a) (b)]	10,690	48,370	7,051	86,742
Realized gain on settlements oil[(a) (b)]		1,932		7,538
Derivative fair value income (loss)	$ 6,546	$ (9,856)	$ 48,879	$ 65,691

(a) Derivatives that do not qualify for hedge accounting.

(b) These amounts represent the realized gains and losses on settled derivatives that do not qualify for hedge accounting, which before settlement are included in the category above called change in fair value of derivatives that do not qualify for hedge accounting.

The combined fair value of derivatives included in our consolidated balance sheets as of June 30, 2010 and December 31, 2009 is summarized below (in thousands). We conduct commodity derivative activities with fourteen financial institutions, thirteen of which are secured lenders in our bank credit facility. We believe all of these institutions are acceptable credit risks. At times, such risks may be concentrated with certain counterparties. The credit worthiness of our counterparties is subject to periodic review. On our balance sheet, derivative assets and liabilities are netted where derivatives with both gain and loss positions are held by a single counterparty.

	June 30, 2010	December 31, 2009
Derivative assets:		
Natural gas collars	$ 113,433	$ 26,649
basis swaps	(1,977)	(1,063)
Crude oil collars	(1,560)	66
	$ 109,896	$ 25,652
Derivative liabilities:		
Natural gas collars	$	$ 2,020
basis swaps	(2,781)	(16,779)
Crude oil collars		
	$ (2,781)	$ (14,759)

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The table below provides data about the fair value of our derivative contracts. Derivative assets and liabilities shown below are presented as gross assets and liabilities, without regard to master netting arrangements, which are considered in the presentation of derivative assets and liabilities in our consolidated balance sheets (in thousands):

	June 30, 2010			December 31, 2009		
	Assets	(Liabilities)		Assets	(Liabilities)	
	Carrying Value	Carrying Value	Net Carrying Value	Carrying Value	Carrying Value	Net Carrying Value
Derivatives that qualify for cash flow hedge accounting:						
Collars[(1)]	$ 93,448	$	$ 93,448	$ 22,062	$	$ 22,062
	$ 93,448	$	$ 93,448	$ 22,062	$	$ 22,062
Derivatives that do not qualify for hedge accounting:						
Collars[(1)]	$ 20,574	$ (2,149)	$ 18,425	$ 6,673	$	$ 6,673
Basis swaps[(1)]		(4,758)	(4,758)	65	(17,907)	(17,842)
	$ 20,574	$ (6,907)	$ 13,667	$ 6,738	$ (17,907)	$ (11,169)

(1) Included in unrealized derivative gain (loss) on our consolidated balance sheets.

The effects of our cash flow hedges on accumulated other comprehensive income (loss) on the consolidated balance sheets are summarized below:

	Three Months Ended June 30,				Six Months Ended June 30,			
	Change in Hedge Derivative Fair Value		Realized Gain (Loss) Reclassified from OCI into Revenue [(a)]		Change in Hedge Derivative Fair Value		Realized Gain (Loss) Reclassified from OCI into Revenue [(a)]	
	2010	2009	2010	2009	2010	2009	2010	2009
Collars	$ (6,868)	$ (4,760)	$ 18,340	$ 53,156	$ 77,943	$ 69,320	$ 19,555	$ 104,479
Income taxes	2,611	1,760	(6,969)	(19,668)	(29,618)	(26,137)	(7,431)	(38,657)
	$ (4,257)	$ (3,000)	$ 11,371	$ 33,488	$ 48,325	$ 43,183	$ 12,124	$ 65,822

(a)

For realized gains upon contract settlement, the reduction in other comprehensive income is offset by an increase in oil and gas revenue. For realized losses upon contract settlement, the increase in other comprehensive income is offset by a decrease in oil and gas revenue.

The effects of our non-hedge derivatives and the ineffective portion of our hedge derivatives on our consolidated statements of operations is summarized below:

	Three Months Ended June 30,					
	Gain (Loss) Recognized in Income (Non-hedge Derivatives)		Gain (Loss) Recognized in Income (Ineffective Portion)		Derivative Fair Value Income (Loss)	
	2010	2009	2010	2009	2010	2009
Swaps	$	$ 5,558	$	$	$	$ 5,558
Collars	1,483	(6,713)	265	1,437	1,748	(5,276)
Basis Swaps	4,798	(10,138)			4,798	(10,138)
Total	$ 6,281	$ (11,293)	$ 265	$ 1,437	$ 6,546	$ (9,856)

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	Six Months Ended June 30,					
	Gain (Loss) Recognized in Income (Non-hedge Derivatives)		Gain (Loss) Recognized in Income (Ineffective Portion)		Derivative Fair Value Income (Loss)	
	2010	2009	2010	2009	2010	2009
Swaps	$	$ 53,558	$	$	$	$ 53,558
Collars	48,438	24,870	(341)	1,481	48,097	26,351
Basis Swaps	782	(14,218)			782	(14,218)
Total	$ 49,220	$ 64,210	$ (341)	$ 1,481	$ 48,879	$ 65,691

(12) FAIR VALUE MEASUREMENTS

Fair Values-Recurring

We use a market approach for our fair value measurements and endeavor to use the best information available. Accordingly, valuation techniques that maximize the use of observable impacts are favored. The following presents the fair value hierarchy table for assets and liabilities measured at fair value, on a recurring basis (in thousands):

	Fair Value Measurements at June 30, 2010 Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of June 30, 2010
Trading securities held in the deferred compensation plans	$ 42,947	$	$	$ 42,947
Derivatives collars		111,873		111,873
basis swaps		(4,758)		(4,758)

These items are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. Our trading securities in Level 1 are exchange-traded and measured at fair value with a market approach using June 30, 2010 market values. Derivatives in Level 2 are measured at fair value with a market approach using third-party pricing services, which have been corroborated with data from active markets or broker quotes.

Our trading securities held in the deferred compensation plan are accounted for using the mark-to-market accounting method and are included as Other assets on our consolidated balance sheet. We elected to adopt the fair value option to simplify our accounting for the investments in our deferred compensation plan. Interest, dividends and mark-to-market gains/losses are included as Deferred compensation plan expense on our consolidated statement of operations. For the three months ended June 30, 2010, interest and dividends were $39,000 and mark-to-market was a gain of $3.2 million. For the three months ended June 30, 2009, interest and dividends were $50,000 and mark-to-market was a gain of $4.9 million. For the six months ended June 30, 2010, interest and dividends were $71,000 and mark-to-market was a gain of $3.8 million. For the six months ended June 30, 2009, interest and dividends were $93,000 and mark-to-market was a gain of $3.4 million. For additional information on the accounting for our deferred compensation plan, see Note 13.

Fair Values-Nonrecurring

The following table shows the values of assets measured at fair value on a nonrecurring basis in periods subsequent to their initial recognition.

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	Three Months Ended June 30,				Six Months Ended June 30,			
	2010		2009		2010		2009	
	Fair Value	Impairment	Fair Value	Impairment	Fair Value	Impairment	Fair Value	Impairment
Long-lived asset held for use	$	$	$	$	$16,075	$6,505	$	$

In the first quarter 2010, we recorded oil and gas property impairment of $6.5 million. Due to declining gas prices, the fair value of our Gulf Coast property depletion pool, at the time of impairment, was measured at $16.1 million using an estimate of future cash flows with Level 3 inputs. This resulted in an impairment of $6.5 million. The fair value of the assets impaired was measured using an income approach based upon internal estimates of future production levels, prices and discount rate, which are Level 3 inputs.

Fair Values-Reported

The following table presents the carrying amounts and the fair values of our financial instruments as of June 30, 2010 and December 31, 2009 (in thousands):

	June 30, 2010		December 31, 2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Assets:				
Commodity collars and basis swaps	$ 109,896	$ 109,896	$ 25,652	$ 25,652
Marketable securities[a]	42,947	42,947	43,554	43,554
Liabilities:				
Commodity collars and basis swaps	(2,781)	(2,781)	(14,759)	(14,759)
Long-term debt[b]	(1,859,562)	(1,876,562)	(1,707,833)	(1,826,458)

[a] Marketable securities are held in our deferred compensation plans.

[b] The book value of our bank debt approximates fair value because of its floating rate structure. The fair value of our senior subordinated notes is based on end of period market quotes.

Concentration of Credit Risk

Most of our receivables are from a diverse group of companies, including major energy companies, pipeline companies, local distribution companies, financial institutions and end-users in various industries. Letters of credit or other appropriate security are obtained as necessary to limit risk of loss. Our allowance for uncollectible receivables was $1.4 million at June 30, 2010 and $2.2 million at December 31, 2009. Commodity-based contracts expose us to the credit risk of nonperformance by the counterparty to the contracts. As of June 30, 2010, these contracts consist of collars and basis swaps. This exposure is diversified among major investment grade financial institutions and we have master netting agreements with the counterparties that provide for offsetting payables against receivables from separate derivative contracts. Our derivative counterparties include fourteen financial institutions, thirteen of which are secured lenders in our bank credit facility. Our oil and gas assets provide collateral under our credit facility and our derivative exposure. J. Aron & Company is the only counterparty not in our bank group. At June 30, 2010, our net derivative payable includes a payable to J. Aron & Company of $463,000. None of our derivative contracts have margin requirements or collateral provisions that would require funding prior to the scheduled cash settlement date.

(13) EMPLOYEE BENEFIT AND EQUITY PLANS

We have two active equity-based stock plans. Under these plans, incentive and nonqualified options, SARs and annual cash incentive awards may be issued to employees and directors pursuant to decisions of the Compensation Committee, which is made up of non-employee, independent directors from the Board of Directors. All awards granted have been issued at prevailing market prices at the time of the grant. Since the middle of 2005, only SARs have been granted under the plans to limit the dilutive impact of our equity plans. Information with respect to stock option and SARs activities is summarized below:

	Shares	Weighted Average Exercise Price
Outstanding on December 31, 2009	7,154,712	$ 31.38
Granted	1,376,581	46.17
Exercised	(1,510,525)	19.09
Expired/forfeited	(47,269)	47.37
Outstanding on June 30, 2010	6,973,499	$ 36.85

The weighted average fair value of an option/SAR to purchase one share of common stock granted during 2010 was $17.05. The fair value of each stock option/SAR granted during 2010 was estimated as of the date of grant using the Black-Scholes-Merton option-pricing model based on the following average assumptions: risk-free interest rate of 1.6%; dividend yield of 0.3%; expected volatility of 49% and an expected life of 3.6 years. Of the 7.0 million stock option/SARs outstanding at June 30, 2010, 820,000 are stock options and 6.2 million are SARs.

Restricted Stock Grants

During the first six months of 2010, 385,000 shares of restricted stock (or non-vested shares) were issued to employees at an average price of $45.97 with a three-year vesting period and 21,000 shares were granted to directors at an average price of $45.51 with immediate vesting. In the first six months of 2009, we issued 532,900 shares of restricted stock as compensation to employees at an average price of $37.70 with a three-year vesting period and 22,700 shares were granted to our directors at an average price of $41.60 with immediate vesting. We recorded compensation expense related to restricted stock grants which is based upon the market value of the shares on the date of grant of $11.5 million in the first six months of 2010 compared to $8.8 million in the six month period ended June 30, 2009. As of June 30, 2010, unrecognized compensation cost related to restricted stock awards was $32.1 million, which is expected to be recognized over the weighted average period of 2 years. Substantially all of our restricted stock grants are held in our deferred compensation plans. All restricted stock awards held in our deferred compensation plan is classified as a liability award and remeasured at fair value each reporting period. This mark-to-market is reported as Deferred compensation plan expense in our consolidated statement of operations (see additional discussion below). All awards granted have been issued at prevailing market prices at the time of the grant and the vesting of these shares is based upon an employee s continued employment with us.

A summary of the status of our non-vested restricted stock outstanding at June 30, 2010 is presented below:

	Shares	Weighted Average Grant Date Fair Value
Non-vested shares outstanding at December 31, 2009	627,189	$ 45.64
Granted	405,802	45.95
Vested	(246,542)	46.15
Forfeited	(7,033)	43.17
Non-vested shares outstanding at June 30, 2010	779,416	$ 45.66

Deferred Compensation Plan

Our deferred compensation plan gives directors, officers and key employees the ability to defer all or a portion of their salaries and bonuses and invest such amounts in Range common stock or make other investments at the individual s discretion. The assets of the plan are held in a grantor trust, which we refer to as the Rabbi Trust, and are therefore available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. Our stock granted and held in the Rabbi Trust is treated as a liability award as employees are allowed to take withdrawals either in cash or in Range stock. The liability associated with the vested portion of the stock is adjusted to fair value each reporting period by a charge or credit to deferred compensation plan expense on our consolidated statement of operations. The assets of the Rabbi Trust, other than Range common stock, are invested in marketable securities and reported at market value as Other assets on our consolidated balance sheet. Changes in the market value of the securities are charged or credited to Deferred compensation plan expense each quarter. The Deferred compensation liability on our consolidated balance sheet reflects the vested market value of the marketable securities and Range common stock held in the Rabbi Trust. We recorded non-cash, mark-to-market income

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related to our deferred compensation plan of $14.1 million in the three months ended June 30, 2010 compared to expense of $756,000 in the same period of 2009. We recorded non-cash, mark-to-market income related to our deferred compensation plan of $19.8 million in first six months 2010 compared to mark-to-market expense of $13.2 million in first six months 2009.

(14) SUPPLEMENTAL CASH FLOW INFORMATION

	Six Months Ended June 30,	
	2010	2009
	(in thousands)	
Non-cash investing and financing activities included:		
Asset retirement costs capitalized, net	$ 864	$ (3,866)
Unproved property purchased with stock[a]	$ 20,000	$ 15,920
Market value of restricted stock issued	$ 18,328	$ 18,255
Shares of restricted stock issued	398,769	475,306
Net cash provided from operating activities included:		
Interest paid	$ 58,457	$ 51,185
Income taxes paid (refunded)	$ (684)	$ 507

(a) Shares were issued in January 2010 while the value was accrued and included in Costs Incurred for the year ended December 31, 2009 (see Note 17).

(15) COMMITMENTS AND CONTINGENCIES

Litigation

We are involved in various legal actions and claims arising in the ordinary course of our business. While the outcome of these lawsuits cannot be predicted with certainty, we do not expect these matters to have a material adverse effect on our financial position, cash flows or results of operations.

(16) CAPITALIZED COSTS AND ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION[a]

	June 30, 2010	December 31, 2009
	(in thousands)	
Oil and gas properties:		
Properties subject to depletion	$ 5,732,690	$ 5,534,204
Unproved properties	789,577	774,503

Total	6,522,267	6,308,707
Accumulated depreciation, depletion and amortization	(1,466,754)	(1,409,888)
Net capitalized costs	$ 5,055,513	$ 4,898,819

(a) Includes capitalized asset retirement costs and associated accumulated amortization.

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(17) COSTS INCURRED FOR PROPERTY ACQUISITIONS, EXPLORATION AND DEVELOPMENT[a]

	Six Months Ended June 30, 2010	Year Ended December 31, 2009
	(in thousands)	
Acquisitions:		
Unproved leasehold	$ 2,646	$
Proved oil and gas properties	132,338	
Asset retirement obligations	556	
Acreage purchases[b]	52,199	176,867
Development	375,555	497,702
Exploration:		
Drilling	24,199	57,121
Expense	26,904	42,082
Stock-based compensation expense	2,205	4,817
Gas gathering facilities	12,406	29,524
Subtotal	629,008	808,113
Asset retirement obligations	864	6,131
Total costs incurred	$ 629,872	$ 814,244

(a) Includes costs incurred whether capitalized or expensed.

(b) The year ended December 31, 2009 includes $20.0 million accrued for acreage purchases of which 380,229 shares were issued in January 2010.

(18) OFFICE CLOSING AND EXIT ACTIVITIES

In February 2010, we entered into an agreement to sell our tight gas sand properties in Ohio. We closed approximately 90% of the sale in March 2010 and closed the remainder of the sale in June 2010. The first quarter 2010 includes $5.1 million accrued severance costs, which is reflected in Termination costs on our consolidated statement of operations. As part of their severance agreement, our Ohio employees vesting of SARs and restricted stock grants was accelerated, increasing our Termination costs for stock compensation expense in first quarter 2010 by approximately $2.8 million.

In third quarter 2009, we announced the closing of our Gulf Coast area office in Houston, Texas. In the year ended December 31, 2009, we accrued $1.3 million of severance costs. The properties are now operated out of our Southwest Area office in Fort Worth.

In December 2009, we sold our natural gas properties in New York. In fourth quarter 2009, we accrued $635,000 of severance costs related to this divestiture.

The following table details our exit activities, which are included in accrued liabilities in our consolidated balance sheet as of June 30, 2010 (in thousands):

Balance at December 31, 2009	$ 1,568
Accrued one-time termination costs	5,138
Payments	(3,254)
Balance at June 30, 2010	$ 3,452

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

Certain sections of Management s Discussion and Analysis of Financial Condition and Results of Operations include forward-looking statements concerning trends or events potentially affecting our business. These statements typically contain words such as anticipates, believes, estimates, expects, targets, plans, could, may, sh similar words indicating that future outcomes are uncertain. In accordance with safe harbor provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, which could cause future outcomes to differ materially from those set forth in forward-looking statements. For additional risk factors affecting our business, see Item 1A. Risk Factors.

Critical Accounting Estimates and Policies

The preparation of financial statements in accordance with generally accepted accounting principles requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Actual results could differ from the estimates and assumptions used. These policies and estimates are described in our 2009 Annual Report on Form 10-K. We have identified the following critical accounting policies and estimates used in the preparation of our financial statements: accounting for oil and gas revenue, oil and gas properties, stock-based compensation, derivative financial instruments, asset retirement obligations and deferred income taxes.

Market Conditions

Prices for various quantities of oil and gas that we produce significantly impact our revenues and cash flows. Prices have been volatile in recent years. The following table lists average NYMEX prices for oil and natural gas for the three and six months ended June 30, 2010 and 2009.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Average NYMEX prices[(a)]				
Oil (per bbl)	$77.72	$59.77	$78.28	$51.54
Natural gas (per mcf)	$ 4.08	$ 3.59	$ 4.72	$ 4.21

(a) Based on average of bid week prompt month prices.

Results of Operations

Overview

Total revenues increased $44.4 million, or 25% for second quarter 2010 over the same period of 2009. The increase includes a $14.3 million increase in oil and gas sales, a gain recorded from the sale of the final portion of our tight gas sand properties in Ohio of $10.4 million and an increase in derivative fair value income (loss) of $16.4 million. Oil and gas sales vary due to changes in volumes of production sold and realized commodity prices. Due to volatility in oil and gas prices, realized prices decreased from the same period of the prior year, which was more than offset by an increase in production, including a 67% increase in natural gas liquid (NGL) production from the same period of the prior year due to increased liquids-rich production in our Appalachian area. For second quarter 2010, production increased 9% from the same period of the prior year while realized prices (including all derivative settlements) declined 18%. We believe oil and gas prices will remain volatile and will be affected by, among other things, weather, the U.S. and worldwide economy, new regulations, new technology, and the level of oil and gas production in North America and worldwide. Although we have entered into derivative contracts covering a portion of our production volumes for 2010 and 2011, a sustained lower price environment would result in lower realized prices for unprotected volumes and reduce the prices we can enter into derivative contracts on additional volumes in the future.

With the lower commodity price environment, we continue to focus our efforts on improving our operating efficiency. These efforts resulted in 22% lower direct operating expense per mcfe for second quarter 2010 when compared to the same period of the prior year. We continue to experience increases in general and administrative expenses per mcfe as we continue to hire employees to staff our Marcellus Shale operations.

Oil and Gas Sales, Production and Realized Price Calculation

Our oil and gas sales vary from quarter to quarter as a result of changes in realized commodity prices and volumes of production sold. Hedges included in oil and gas sales reflect settlement on those derivatives that qualify for hedge accounting. Cash settlement of derivative contracts that are not accounted for as hedges are included in our consolidated statement of operations category called derivative fair value income (loss). The following table summarizes the primary components of oil and gas sales for the three months and the six months ended June 30, 2010 and 2009 (in thousands):

	Three Months Ended June 30,				Six Months Ended June 30,			
	2010	2009	Change	%	2010	2009	Change	%
Oil wellhead	$ 32,913	$ 39,943	$ (7,030)	(18%)	$ 68,797	$ 68,023	$ 774	1%
Oil hedges realized	23	2,642	(2,619)	(99%)	23	12,007	(11,984)	(100%)
Total oil sales	32,936	42,585	(9,649)	(23%)	68,820	80,030	(11,210)	(14%)
Gas wellhead	122,923	86,722	36,201	42%	286,693	203,642	83,051	41%
Gas hedges realized	18,317	50,514	(32,197)	(64%)	19,532	92,472	(72,940)	(79%)
Total gas sales	141,240	137,236	4,004	3%	306,225	296,114	10,111	3%
NGL	32,608	12,702	19,906	157%	68,499	19,568	48,931	250%
Combined wellhead	188,444	139,367	49,077	35%	423,989	291,233	132,756	46%
Combined hedges realized	18,340	53,156	(34,816)	(65%)	19,555	104,479	(84,924)	(81%)
Total oil and gas sales	$206,784	$192,523	$ 14,261	7%	$443,544	$395,712	$ 47,832	12%

Our production continues to grow through continued drilling success as we place new wells into production, partially offset by the natural decline of our oil and gas wells and asset sales. For second quarter 2010, total production volumes as compared to the same period of the prior year, increased 43% in our Appalachian area and decreased 13% in our Southwestern area. For the six months ended June 30, 2010, our production volumes as compared to the same period of the prior year, increased 45% in our Appalachia area and decreased 11% in our Southwestern area. NGL production increased 67% from the same period of the prior year due to increased liquids-rich gas production in our Appalachia area along with an increase in processing capacity in the region. Crude oil production declined primarily due to the sale of oil properties in West Texas effective June 30, 2009. Our production for the three months and the six months ended June 30, 2010 and 2009 is shown below:

	Three Months Ended	Six Months Ended

	June 30,				June 30,			
	2010	2009	Change	%	2010	2009	Change	%
Production[a]:								
Crude oil (bbls)	484,742	731,244	(246,502)	(34%)	999,420	1,453,204	(453,784)	(31%)
NGLs (bbls)	878,219	525,993	352,226	67%	1,709,355	949,254	760,101	80%
Natural gas (mcf)	34,751,687	31,905,593	2,846,094	9%	68,502,246	62,457,926	6,044,320	10%
Total (mcfe)[b]	42,929,453	39,449,015	3,480,438	9%	84,754,896	76,872,674	7,882,222	10%
Average daily production[a]:								
Crude oil (bbls)	5,327	8,036	(2,709)	(34%)	5,522	8,029	(2,507)	(31%)
NGLs (bbls)	9,651	5,780	3,871	67%	9,444	5,244	4,200	80%
Natural gas (mcf)	381,887	350,611	31,276	9%	378,465	345,071	33,394	10%
Total (mcfe)[b]	471,752	433,506	38,246	9%	468,259	424,711	43,548	10%

(a) Represents volumes sold regardless of when produced.

(b) Oil and NGLs are converted at the rate of one barrel equals six mcf.

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Our average realized price (including all derivative settlements) received for oil and gas was $5.07 per mcfe in second quarter 2010 compared to $6.18 per mcfe in the same period of the prior year. Our average realized price calculation (including all derivative settlements) includes all cash settlement for derivatives, whether or not they qualify for hedge accounting. Our oil and gas revenues and realized prices for the three months and the six months ended June 30, 2010, when compared to the same periods of 2009, were negatively impacted by settled losses on our basis swaps and by premiums paid for natural gas collars that were settled during the period. This reduced our average realized price by $0.25 per mcfe in the second quarter 2010 and $0.23 per mcfe in the six months ended June 30, 2010 compared to increases of $0.01 per mcfe in the second quarter 2009 and $0.04 per mcfe in the six months ended June 30, 2009. Average price calculations for the three months and the six months ended June 30, 2010 and 2009 are shown below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Average sales prices (wellhead):				
Crude oil (per bbl)	$67.90	$54.62	$68.83	$46.80
NGLs (per bbl)	$37.13	$24.15	$40.07	$20.61
Natural gas (per mcf)	$ 3.54	$ 2.72	$ 4.19	$ 3.26
Total (per mcfe)[(a)]	$ 4.39	$ 3.53	$ 5.00	$ 3.79
Average realized price (including derivatives that qualify for hedge accounting):				
Crude oil (per bbl)	$67.95	$58.23	$68.86	$55.07
NGLs (per bbl)	$37.13	$24.15	$40.07	$20.61
Natural gas (per mcf)	$ 4.06	$ 4.30	$ 4.47	$ 4.74
Total (per mcfe)[(a)]	$ 4.82	$ 4.88	$ 5.23	$ 5.15
Average realized price (including all derivative settlements):				
Crude oil (per bbl)	$67.96	$60.88	$68.86	$60.26
NGLs (per bbl)	$37.13	$24.15	$40.07	$20.61
Natural gas (per mcf)	$ 4.37	$ 5.85	$ 4.57	$ 6.15
Total (per mcfe)[(a)]	$ 5.07	$ 6.18	$ 5.31	$ 6.39

(a) Oil and NGLs are converted at the rate of one barrel equals six mcf.

Derivative fair value income (loss) was a gain of $6.5 million in second quarter 2010 compared to a loss of $9.9 million in the same period of 2009. Derivative fair value income (loss) was a gain of $48.9 million in the six months ended June 30, 2010 compared to $65.7 million in the same period of 2009. Some of our derivatives do not qualify for hedge accounting and are accounted for using the mark-to-market accounting method whereby all realized and unrealized gains and losses related to these contracts are included in derivative fair value income (loss). We have also entered into basis swap agreements, which do not qualify for hedge accounting and are also marked to market. Mark-to-market accounting treatment creates volatility in our revenues as unrealized gains and losses from non-hedge derivatives are included in total revenues and are not included in accumulated other comprehensive income in our consolidated balance sheet. Hedge ineffectiveness, also included in this statement of operations category, is associated with our hedging contracts that qualify for hedge accounting.

The following table presents information about the components of derivative fair value income for the three months and the six months June 30, 2010 and 2009 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Hedge ineffectiveness realized[c]	$ 5	$ 1,081	$ (352)	$ 1,578
unrealized[a]	260	356	11	(97)
Change in fair value of derivatives that do not qualify for hedge accounting[a]	(4,409)	(61,595)	42,169	(30,070)
Realized gain on settlements gas[b](c)	10,690	48,370	7,051	86,742
Realized gain on settlements oil[b](c)		1,932		7,538
Derivative fair value income	$ 6,546	$ (9,856)	$ 48,879	$ 65,691

(a) These amounts are unrealized and are not included in average sales price calculations.

(b) These amounts represent realized gains and losses on settled derivatives that do not qualify for hedge accounting.

(c) These settlements are included in average realized price calculations (average realized price including all derivative settlements).

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Gain (loss) on the sale of assets for second quarter 2010 increased $10.2 million from the same period of the prior year. In the second quarter, we closed the remainder of the sale of our tight gas sand properties in Ohio and recorded a gain of $10.4 million. For the six months ended June 30, 2010, we recorded a gain of $77.4 million from the sale of our tight gas sand properties in Ohio and received proceeds of $323.0 million.

Other income (loss) for second quarter 2010 was a gain of $637,000 compared to a loss of $4.4 million in the same period of 2009. Second quarter 2010 includes income from equity method investments of $636,000. The second quarter of 2009 includes a loss from equity method investments of $4.6 million. Other income (loss) for the six months ended June 30, 2010 increased from a loss of $6.2 million in 2009 to a loss of $938,000 in 2010. Loss from equity method investments for the six months ended June 30, 2010 was a loss of $985,000 compared to a loss of $5.5 million in the same period of 2009.

We believe some of our expense fluctuations are best analyzed on a unit-of-production, or per mcfe, basis. The following presents information about these expenses on a per mcfe basis for the three months and the six months ended June 30, 2010 and 2009:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2010	2009	Change	%	2010	2009	Change	%
Direct operating expense	$0.69	$0.88	$(0.19)	(22%)	$0.72	$0.92	$(0.20)	(22%)
Production and ad valorem tax expense	0.19	0.19		%	0.19	0.21	(0.02)	(10%)
General and administrative expense	0.83	0.74	0.09	12%	0.76	0.70	0.06	9%
Interest expense	0.72	0.75	(0.03)	(4%)	0.72	0.73	(0.01)	(1%)
Depletion, depreciation and amortization expense	2.12	2.25	(0.13)	(6%)	2.12	2.25	(0.13)	(6%)

Direct operating expense declined $5.1 million in second quarter 2010 to $29.8 million. We experience increases in operating expenses as we add new wells and maintain production from existing properties. In second quarter 2010, this effect was more than offset by cost containment measures, lower overall industry costs and asset sales. On an absolute dollar basis, our spending for direct operating expense (excluding workovers and expenses on our sold properties) was the same for the three months ended June 30, 2010, when compared to the same period of 2009, despite higher production levels, due to cost containment measures and lower overall industry costs. We incurred $1.3 million ($0.03 per mcfe) of workover costs in second quarter 2010 versus $931,000 ($0.02 per mcfe) in 2009. On a per mcfe basis, direct operating expenses for second quarter 2010 decreased $0.19, or 22%, from the same period of 2009 with the decrease consisting primarily of lower utility costs ($0.01 per mcfe), lower water disposal costs ($0.01 per mcfe), lower overall well service costs and asset sales. We expect to continue to experience lower costs per mcfe as we increase production from our Marcellus Shale wells due to their lower operating costs. Direct operating expense was $60.8 million for the first six months of 2010 compared to $70.4 million in the same period of the prior year. We incurred $2.7 million ($0.03 per mcfe) of workover costs in the first six months of 2010 compared to $2.7 million ($0.03 per mcfe) in 2009. On a per mcfe basis, direct operating expenses for the six months 2010 decreased $0.20, or 22% from the same period of the prior year with the decrease consisting primarily of lower water disposal costs ($0.03 per mcfe), lower utilities ($0.01 per mcfe), lower overall well service costs and asset sales. Stock-based compensation included in this category represents amortization of restricted stock grants and expense related to SAR grants. The following table summarizes direct operating expenses per mcfe for the three months and the six months ended June 30, 2010 and 2009:

The second quarter 2009 included $6.6 million of operating costs related to properties sold during 2009 and in the first quarter 2010. On a per mcfe basis, excluding expenses on these properties that have been sold, our 2009 direct operating expense would have been $0.80. The first six months of 2009 included $10.4 million of operating costs related to properties sold during 2009 and in the first quarter 2010. On a per mcfe basis, excluding expenses on these properties that have been sold, our 2009 direct operating expense would have been $0.84.

	Three Months Ended June 30,				Six Months Ended June 30,			
	2010	2009	Change	%	2010	2009	Change	%
Lease operating expense	$0.65	$0.84	$(0.19)	(23%)	$0.68	$0.87	$(0.19)	(22%)
Workovers	0.03	0.02	0.01	50%	0.03	0.03		%
Stock-based compensation (non-cash)	0.01	0.02	(0.01)	(50%)	0.01	0.02	(0.01)	(50%)
Total direct operating expenses	$0.69	$0.88	$(0.19)	(22%)	$0.72	$0.92	$(0.20)	(22%)

Production and ad valorem taxes are paid based on market prices and not hedged prices. For the second quarter, these taxes increased $526,000 or 7% from the same period of the prior year due to higher market prices which were somewhat offset by lower property taxes and an increase in production volumes not subject to production taxes. On a per mcfe basis, production and ad valorem taxes was $0.19 in both the second quarter 2010 and the second quarter 2009. For the first six months of 2010, these taxes increased 2% from the same period of the prior year due to higher market prices which was significantly offset by lower property taxes and an increase in production volumes not subject to production taxes. On a per mcfe basis, production and ad valorem taxes decreased to $0.19 in the first six months of 2010 compared to $0.21 in the same period of 2009.

General and administrative expense for second quarter 2010 increased $6.7 million or 23% from the same period of the prior year due primarily to higher stock-based compensation ($1.8 million), slightly higher salaries and benefits ($292,000) an increase in legal fees and lawsuit settlements ($2.8 million) higher accounting and auditing fees ($350,000) and higher office expenses, including information technology and industry association dues. General and administrative expense for the first six months of 2010 increased $10.0 million or 19% from the same period of the prior year due to higher stock-based compensation ($2.9 million), an increase in legal fees and lawsuit settlements ($3.0 million), higher salaries and benefits ($1.4 million) and higher office expenses, including information technology and industry association dues. Stock-based compensation included in this category represents amortization of restricted stock grants and expense related to SAR grants. The following table summarizes general and administrative expenses per mcfe for the three months and the six months ended June 30, 2010 and 2009:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2010	2009	Change	%	2010	2009	Change	%
General and administrative	$0.58	$0.51	$0.07	14%	$0.54	$0.50	$0.04	8%
Stock-based compensation (non-cash)	0.25	0.23	0.02	9%	0.22	0.20	0.02	10%
Total general and administrative expenses	$0.83	$0.74	$0.09	12%	$0.76	$0.70	$0.06	9%

Interest expense for second quarter 2010 increased $1.2 million from the same period of the prior year due to the refinancing of certain debt from floating to higher fixed rates which was somewhat offset by lower overall debt balances. In May 2009, we issued $300.0 million of 8.0% senior subordinated notes due 2019, which added $2.9 million of interest costs in second quarter 2010. The proceeds from the issuance were used to retire lower floating interest rate bank debt, to better match the maturities of our debt with the life of our properties and to give us greater liquidity for the near term. Average debt outstanding on the bank credit facility for second quarter 2010 was $421.1 million compared to $715.6 million for the same period of the prior year and the weighted average interest rate was 2.2% in second quarter 2010 compared to 2.5% in the same period of the prior year. Interest expense for the six months ended June 30, 2010 increased $4.9 million or 9% from the same period of the prior year due to the refinancing of certain debt from floating to higher fixed rates which was somewhat offset by lower overall debt balances. Average debt outstanding on the bank credit facility for the six months ended June 30, 2010, was $390.4 million compared to $751.4 million for the same period of the prior year and the weighted average interest rates was 2.2% in the first six months of 2010 compared to 2.6% in the same period of the prior year.

Depletion, depreciation and amortization (DD&A) increased $2.3 million, or 3%, to $91.0 million in second quarter 2010. The increase was due to a 9% increase in production and was partially offset by a 4% decrease in depletion rates. On a per mcfe basis, DD&A decreased from $2.25 in second quarter 2009 to $2.12 in second quarter 2010. In the first six months of 2010, DD&A increased $6.6 million due to a 10% increase in production and was partially offset by a 5% decrease in depletion rates. The following table summarizes DD&A expenses per mcfe for the three months and the six months ended June 30, 2010 and 2009:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2010	2009	Change	%	2010	2009	Change	%
Depletion and amortization	$2.01	$2.10	$(0.09)	(4%)	$1.99	$2.10	$(0.11)	(5%)
Depreciation	0.08	0.12	(0.04)	(3%)	0.10	0.12	(0.02)	(17%)
Accretion and other	0.03	0.03		%	0.03	0.03		%
Total DD&A expense	$2.12	$2.25	$(0.13)	(6%)	$2.12	$2.25	$(0.13)	(6%)

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Our total operating expenses also include other expenses that generally do not trend with production. These expenses include stock-based compensation, exploration expense, abandonment and impairment of unproved properties, termination costs, deferred compensation plan expenses and impairment of proved properties. In the three months and the six months ended June 30, 2010 and 2009, stock-based compensation represents the amortization of restricted stock grants and expenses related to SAR grants. In second quarter 2010, stock-based compensation is a component of direct operating expense ($625,000), exploration expense ($1.1 million) and general and administrative expense ($10.7 million) for a total of $12.7 million. In second quarter 2009, stock-based compensation was a component of direct operating expense ($830,000), exploration expense ($893,000) and general and administrative expense ($8.9 million) for a total of $10.8 million. In the six months ended June 30, 2010, stock based compensation is a component of direct operating expense ($1.1 million), exploration expense ($2.2 million), general and administrative expense ($18.6 million) and termination costs ($2.8 million) for a total of $25.3 million. In the six months ended June 30, 2009, stock based compensation is a component of direct operating expense (1.6 million), exploration expense ($2.0 million), general and administrative expense ($15.2 million) for a total of $19.1 million.

Exploration expense increased $3.1 million in second quarter 2010 and increased $4.4 million in the first six months of 2010 primarily due to higher delay rental costs partially offset by lower seismic costs. The following table details our exploration-related expenses for the three months and the six months ended June 30, 2010 and 2009 (in thousands):

	Three Months Ended June 30,				Six Months Ended June 30,			
	2010	2009	Change	%	2010	2009	Change	%
Dry hole expense	$	$ 8	$ (8)	(100%)	$	$ 131	$ (131)	(100%)
Seismic	878	5,717	(4,839)	(85%)	8,559	13,915	(5,356)	(63%)
Personnel expense	2,910	2,836	74	3%	5,640	5,705	(65)	(1)%
Stock-based compensation expense	1,069	893	176	20%	2,205	1,954	251	13%
Delay rentals and other	9,616	1,914	7,702	402%	12,704	3,002	9,702	323%
Total exploration expense	$14,473	$11,368	$ 3,105	27%	$29,108	$24,707	$ 4,401	18%

Abandonment and impairment of unproved properties expense was $13.5 million during the three months ended June 30, 2010 compared to $41.0 million during the same period of 2009. Abandonment and impairment of unproved properties was $25.9 million in the six months ended June 30, 2010 compared to $60.5 million during the same period for 2009. Abandonment and impairment of unproved properties in 2009 was primarily related to individually significant Barnett Shale lease expirations. We assess individually significant unproved properties for impairment on a quarterly basis and recognize a loss at the time of impairment. In determining whether a significant unproved property is impaired we consider numerous factors including, but not limited to, current exploration plans, favorable or unfavorable activity on the property being evaluated and/or adjacent properties, our geologists evaluation of the property and the remaining months in the lease term for the property. Impairment of individually insignificant unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success.

Termination costs in the first six months of 2010 includes severance costs of $5.1 million related to the sale of our tight gas sand properties in Ohio and $2.8 million of non-cash stock-based compensation expense related to the accelerated vesting of SARs and restricted stock as part of the severance agreement for our Ohio personnel.

Deferred compensation plan expense was income of $14.1 million in second quarter 2010 compared to expense of $756,000 in the same period of the prior year. This non-cash expense relates to the increase or decrease in value of the liability associated with our common stock that is vested and held in the deferred compensation plan. Our stock price decreased from $46.87 at March 30, 2010 to $40.15 at June 30, 2010. During the same period in the prior year, our stock price increased from $41.16 at March 31, 2009 to $41.41 at June 30, 2009. Deferred compensation plan expense was income of $19.8 million in the six months ended June 30, 2010 compared to expense of $13.2 million in the same period of the prior year. Our stock price decreased from $49.85 at December 31, 2009 to $40.15 at June 30, 2010. During the same six month period of 2009, our stock price increased from $34.39 at December 31, 2008 to $41.41 at June 30, 2009. Our deferred compensation liability is adjusted to fair value by a charge or a credit to deferred compensation plan expense.

Impairment of proved properties in the first six months of 2010 of $6.5 million was recognized due to declining gas prices and is related to our Gulf Coast properties. Our estimated fair value of producing properties is generally calculated as the discounted present value of future net cash flows. Our estimates of cash flow are based on the latest available proved reserve and production information and management s estimates of future product prices and costs, based on available information such as forward strip prices.

Income tax expense for second quarter 2010 increased to $6.5 million from a benefit of $22.5 million in second quarter 2009, reflecting a 125% increase in income from operations before taxes compared to the same period of 2009. Second quarter 2010 provided for tax expense at an effective rate of 41.6% compared to tax benefit at an effective rate of 36.0% in the same period of 2009. Income tax expense for the six months ended June 30, 2010 increased to $55.4 million from a benefit of $3.7 million in the same period of 2009, reflecting a significant increase in income from operations before taxes compared to the same period of 2009. The six months ended June 30, 2010 provided for a tax expense at an effective tax rate of 39.0% compared to a tax benefit at an effective tax rate of 33.7% in the same period of the prior year. The increase in effective tax rates is primarily due to an increase in non-deductible expenses and an increase in the proportion of our business being derived from higher tax rate jurisdictions. We expect our effective tax rate to be approximately 39% for the remainder of 2010.

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Liquidity, Capital Resources and Capital Commitments

Our main sources of liquidity and capital resources are internally generated cash flow from operations, a bank credit facility with both uncommitted and committed availability, asset sales and access to both the debt and equity capital markets. We continue to take steps to ensure adequate capital resources and liquidity to fund our capital expenditure program. During the first six months of 2010, we sold our shallow tight sand Ohio properties for proceeds of approximately $323.0 million. We have used these proceeds to purchase proved and unproved properties in Virginia. The remainder of these proceeds are expected to be used to develop or purchase additional oil and gas proved or unproved properties. In the first six months 2010, we also entered into additional oil and gas commodity derivative contracts for 2010 and 2011 to protect future cash flows. As part of our semi-annual bank review completed March 31, 2010, our borrowing base and facility amounts were reaffirmed at $1.5 billion and $1.25 billion.

During the six months ended June 30, 2010, our cash provided from operating activities was $260.4 million and we spent $359.7 million on capital expenditures and $187.2 million on proved and unproved property purchases. At June 30, 2010, we had $166.9 million in cash, total assets of $5.8 billion and a debt-to-capitalization ratio of 42.4%. Long-term debt at June 30, 2010 totaled $1.9 billion, which included $475.0 million of bank credit facility debt and $1.4 billion of senior subordinated notes. Available committed borrowing capacity under the bank credit facility at June 30, 2010 was $774.9 million.

In June 2009, we filed a universal shelf registration statement with the Securities and Exchange Commission, under which we, as a well-known seasoned issuer, have the ability, subject to market conditions, to issue and sell an indeterminate amount of various types of registered debt and equity securities.

We establish a capital budget at the beginning of each calendar year. Our 2010 capital budget (excluding acquisitions) now stands at $1.2 billion and focuses on projects we believe will generate and lay the foundation for production growth. In the past, we often have increased our capital budget during the year as a result of acquisitions or successful drilling. We continue to screen for attractive acquisition opportunities; however, the timing and size of acquisitions are unpredictable.

Cash is required to fund capital expenditures necessary to offset inherent declines in production and proven reserves, which is typical in the capital-intensive oil and gas industry. Future success in growing reserves and production will be highly dependent on capital resources available and the success of finding or acquiring additional reserves. We believe that net cash generated from operating activities, unused committed borrowing capacity under the bank credit facility and proceeds from asset sales will be adequate to satisfy near-term financial obligations and liquidity needs. However, our long-term cash flows are subject to a number of variables, including the level of production and prices as well as various economic conditions that have historically affected the oil and gas business. Sustained lower oil and gas prices or a reduction in production and reserves would reduce our ability to fund capital expenditures, reduce debt, meet financial obligations and remain profitable. On June 30, 2010, we have approximately 65% of our remaining 2010 production and 47% of our 2011 production subject to hedging agreements. We operate in an environment with numerous financial and operating risks, including, but not limited to, the inherent risks of the search for, development and production of oil and gas, the ability to buy properties and sell production at prices, which provide an attractive return and the highly competitive nature of the industry. Our ability to expand our reserve base is, in part, dependent on obtaining sufficient capital through internal cash flow, bank borrowings, asset sales or the issuance of debt or equity securities. There can be no assurance that internal cash flow and other capital sources will provide sufficient funds to maintain capital expenditures that we believe are necessary to offset inherent declines in production and proven reserves.

Our opinions concerning liquidity and our ability to avail ourselves in the future of the financing options mentioned in the above forward-looking statements are based on currently available information. If this information proves to be inaccurate, future availability of financing may be adversely affected. Estimates may differ from actual results. Factors that affect the availability of financing include our performance, the state of the worldwide debt and equity markets, investor perceptions and expectations of past and future performance, the global financial climate and, in particular, with respect to borrowings, the level of our outstanding debt and credit ratings by rating agencies.

Credit Arrangements

On June 30, 2010, the bank credit facility had a $1.5 billion borrowing base and a $1.25 billion facility amount. The borrowing base represents an amount approved by the bank group that can be borrowed based on our assets, while our $1.25 billion facility amount is the amount we have requested that the banks commit to fund pursuant to the credit agreement. The bank credit facility provides for a borrowing base subject to redeterminations semi-annually each April and October and for event-driven unscheduled redeterminations. Remaining credit availability was $706.9 million on July 22, 2010. Our bank group is comprised of twenty-six commercial banks, with no one bank holding more than 5.0% of the bank credit facility. We believe our large number of banks and relatively low hold levels allow for significant lending capacity should we elect to increase our $1.25 billion commitment up to the $1.5 billion borrowing base and also allow for flexibility should there be additional consolidation within the banking sector.

Our bank credit facility and our indentures governing our senior subordinated notes all contain covenants that, among other things, limit our ability to pay dividends, incur additional indebtedness, sell assets, enter into hedging contracts change the nature of our business or operations, merge or consolidate or make certain investments. In addition, we are required to maintain a ratio of debt to EBITDAX (as defined in the credit agreement) of no greater than 4.0 to 1.0 and a current ratio (as defined in the credit agreement) of no less than 1.0 to 1.0. We were in compliance with these covenants at June 30, 2010. Please see Note 8 to our consolidated financial statements for additional information.

Cash Flow

Cash flows from operating activities primarily are affected by production and commodity prices, net of the effects of settlements of our derivatives. Our cash flows from operating activities also are impacted by changes in working capital. We sell substantially all of our oil and gas production at the wellhead under floating market contracts. However, we generally hedge a substantial, but varying, portion of our anticipated future oil and gas production for the next 12 to 24 months. Any payments due to counterparties under our derivative contracts should ultimately be funded by higher prices received from the sale of our production. Production receipts, however, often lag payments to the counterparties. Any interim cash needs are funded by borrowing under the credit facility. As of June 30, 2010, we have entered into hedging agreements covering 60.9 Bcfe for 2010 and 104.6 Bcfe for 2011.

Net cash provided from operating activities for the six months ended June 30, 2010 was $260.4 million compared to $268.4 million in the six months ended June 30, 2009. Cash flow from operating activities for the first six months of 2010 was lower than the same period of the prior year, as higher production from development activity was offset by lower realized prices. Net cash provided from operating activities is also affected by working capital changes or the timing of cash receipts and disbursements. Changes in working capital (as reflected in the consolidated statement of cash flows) in the six months ended June 30, 2010 was $18.4 million compared to a negative $26.4 million in the same period of the prior year.

Net cash used in investing activities for the six months ended June 30, 2010 was $229.5 million compared to $215.0 million in the same period of 2009. During the six months ended June 30, 2010, we:

- spent $349.4 million on oil and gas property additions;
- spent $52.2 million on average primarily in the Marcellus Shale;
- spent $135.0 million on the purchase of proved and unproved properties in Virginia; and
- received proceeds of $318.6 million primarily from the sale of Ohio oil and gas properties.

During the six months ended June 30, 2009, we:

- spent $276.0 million on oil and gas property additions;
- spent $107.3 million on acreage primarily in the Marcellus Shale; and
- received proceeds of $182.1 million primarily from the sale of West Texas oil and gas properties.

Net cash provided from financing activities for the six months ended June 30, 2010 was $135.2 million compared to net cash used in financing activities of $52.0 million in the same period of 2009. During the six months ended June 30, 2010, we:

- borrowed $371.0 million and repaid $220.0 million under our bank credit facility, ending the period with $151.0 million higher bank debt and $166.9 million in cash.

During the six months ended June 30, 2009, we:

- borrowed $451.0 million and repaid $741.0 million under our bank credit facility, ending the period with $290.0 million lower bank debt; and
- issued $300.0 million aggregate principal amount of our 8% senior subordinated notes due 2019, at a discount.

Dividends

On June 30, 2010, the Board of Directors declared a dividend of four cents per share ($6.4 million) on our common stock, which was paid on June 30, 2010 to stockholders of record at the close of business on June 15, 2010.

Capital Requirements and Contractual Cash Obligations

We currently estimate our 2010 capital spending will approximate $1.2 billion (excluding acquisitions) and based on current projections is expected to be funded with internal cash flow, property sales, our bank credit facility and the capital markets.

Acreage purchases during the first six months include $44.2 million of purchases in the Marcellus Shale and $3.6 million in the Barnett Shale, which were funded with borrowings under our credit facility. For the six months ended June 30, 2010, $428.9 million of our development and exploration spending was funded with internal cash flow and borrowings under our bank credit facility. We monitor our capital expenditures on a regular basis, adjusting the amount up or down and between our operating regions, depending on commodity prices, cash flow and projected returns. Also, our obligations may change due to acquisitions, divestitures and continued growth. We may sell assets, issue subordinated notes or other debt securities, or issue additional shares of stock to fund capital expenditures or acquisitions, extend maturities or repay debt.

Our contractual obligations include long-term debt, operating leases, drilling commitments, derivative obligations, transportation commitments and other liabilities. Since December 31, 2009, there have been no material changes to our contractual obligations except for an increase in our bank credit facility balance.

Other Contingencies

We are involved in various legal actions and claims arising in the ordinary course of business. We believe the resolution of these proceedings will not have a material adverse effect on our liquidity or consolidated financial position.

Hedging Oil and Gas Prices

We use commodity-based derivative contracts to manage exposure to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. These contracts consist of collars and fixed price swaps. We do not utilize complex derivatives such as swaptions, knockouts or extendable swaps. Reducing our exposure to price volatility helps ensure that we have adequate funds available for our capital program. Our decision on the quantity and price at which we choose to hedge our future production is based in part on our view of current and future market conditions. In light of current worldwide economic uncertainties, we recently have employed a strategy to hedge a portion of our production looking out 12 to 24 months from each quarter. At June 30, 2010, we had collars covering 152.9 Bcf of gas at weighted average floor and cap prices of $5.66 and $6.98 per mcf and 2.1 million barrels of oil at weighted average floor and cap prices of $70.44 and $90.33 per barrel. Their fair value, represented by the estimated amount that would be realized upon termination, based on a comparison of contract prices and a reference price, generally NYMEX, on June 30, 2010 was a net unrealized pre-tax gain of $111.9 million. The contracts expire monthly through December 2011. Settled transaction gains and losses for derivatives that qualify for hedge accounting are determined monthly and are included as increases or decreases in oil and gas sales in the period the hedged production is sold. In the first six months of 2010, oil and gas sales included realized hedging gains of $19.6 million compared to gains of $104.5 million in the same period of 2009.

At June 30, 2010, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Average Hedge Price
Natural Gas			
2010	Collars	325,000 Mmbtu/day	$5.55-$7.20
2011	Collars	255,000 Mmbtu/day	$5.73-$6.83
Crude Oil			
2010	Collars	1,000 bbls/day	$75.00-$93.75
2011	Collars	5,244 bbls/day	$70.00-$90.00

Some of our derivatives do not qualify for hedge accounting or are not designated as a hedge but provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and gas production. These contracts are accounted for using the mark-to-market accounting method. Under this method, the contracts are carried at their fair value as Unrealized derivative gains and losses on our consolidated balance sheet. We recognize all unrealized and realized gains and losses related to these contracts as Derivative fair value income in our consolidated statement of operations. As of June 30, 2010, derivatives on 37.2 Bcfe no longer qualify or are not designated for hedge accounting.

In addition to the swaps and collars above, we have entered into basis swap agreements that do not qualify for hedge accounting and are marked to market. The price we receive for our production can be less than NYMEX price because of adjustments for delivery location (basis), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively fix the basis adjustments. The fair value of the basis swaps was a net unrealized pre-tax loss of $4.8 million at June 30, 2010.

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Interest Rates

At June 30, 2010, we had $1.9 billion of debt outstanding. Of this amount, $1.4 billion bore interest at fixed rates averaging 7.4%. Bank debt totaling $475.0 million bears interest at floating rates, which approximated 2.2% at June 30, 2010. The 30-day LIBOR rate on June 30, 2010 was 0.3%.

Inflation and Changes in Prices

Our revenues, the value of our assets, our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in oil and gas prices and the costs to produce our reserves. Oil and gas prices are subject to fluctuations that are beyond our ability to control or predict. During second quarter 2010, we received an average of $67.90 per barrel of oil and $3.54 per mcf of gas before derivative contracts compared to $54.62 per barrel of oil and $2.72 per mcf of gas in the same period of the prior year. Although certain of our costs are affected by general inflation, inflation does not normally have a significant effect on our business. In a trend that began in 2004 and accelerated through the middle of 2008, commodity prices for oil and gas increased significantly. The higher prices led to increased activity in the industry and, consequently, rising costs. These cost trends put pressure not only on our operating costs but also on capital costs. Due to the decline in commodity prices since then, costs have moderated. We expect costs in 2010 to continue to be a function of supply and demand.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in oil and gas prices and interest rates. The disclosures are not meant to be indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market-risk exposures. All of our market-risk sensitive instruments were entered into for purposes other than trading. All accounts are U.S. dollar denominated.

Financial Market Risk

The debt and equity markets have exhibited adverse conditions since late 2007. The unprecedented volatility and upheaval in the capital markets may increase costs associated with issuing debt instruments due to increased spreads over relevant interest rate benchmarks and affect our ability to access those markets. At this point, we do not believe our liquidity has been materially affected by the recent events in the global markets and we do not expect our liquidity to be materially impacted in the near future. We will continue to monitor our liquidity and the capital markets. Additionally, we will continue to monitor events and circumstances surrounding each of our twenty-six lenders in the bank credit facility. Beginning in late 2009 and continuing into 2010, we have observed improving market conditions. Bank lending availability and access to the long-term debt markets have steadily improved since 2008 and 2009.

Market Risk

Our major market risk is exposure to oil and gas prices. Realized prices are primarily driven by worldwide prices for oil and spot market prices for North American gas production. Oil and gas prices have been volatile and unpredictable for many years.

Commodity Price Risk

We periodically enter into derivative arrangements with respect to our oil and gas production. These arrangements are intended to reduce the impact of oil and gas price fluctuations. At times, certain of our derivatives have been swaps where we receive a fixed price for our production and pay market prices to the counterparty. Our derivatives program also includes collars, which establish a minimum floor price and a predetermined ceiling price. Historically, we applied hedge accounting to derivatives utilized to manage price risk associated with our oil and gas production. Accordingly, we recorded change in the fair value of our swap and collar contracts under the balance sheet caption accumulated other comprehensive income and into oil and gas sales when the forecasted sale of production occurred. Any hedge ineffectiveness associated with contracts qualifying for and designated as a cash flow hedge is reported currently each period under our consolidated statement of operations caption derivative fair value income. Some of our derivatives do not qualify for hedge accounting but provide an economic hedge of our exposure to commodity price risk associated with anticipated future oil and gas production. These contracts are accounted for using the mark-to-market accounting method. Under this method, the contracts are carried at their fair value on our consolidated balance sheet under the captions unrealized derivative gains and losses. We recognize all unrealized and realized gains and losses related to these contracts in our consolidated statement of operations under the caption derivative fair value income. Generally, derivative losses occur when market prices increase, which are offset by gains on the underlying physical commodity transaction. Conversely, derivative gains occur when market prices decrease, which are offset by losses on the underlying commodity transaction. Our derivative counterparties include fourteen financial institutions, thirteen of which are in our bank group. J. Aron & Company is the counterparty not in our bank group. At June 30, 2010, our net derivative payable includes a payable to J. Aron & Company of $463,000. None of our derivative contracts have margin requirements or collateral provisions that would require funding prior to the scheduled cash settlement date.

As of June 30, 2010, we had collars covering 152.7 Bcf of gas and 2.1 million barrels of oil. These contracts expire monthly through December 2011. The fair value, represented by the estimated amount that would be realized upon immediate liquidation as of June 30, 2010, approximated a net unrealized pre-tax gain of $111.9 million.

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At June 30, 2010, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Average Hedge Price	Fair Market Value as of June 30, 2010 Asset (Liability) (in thousands)
Natural Gas				
2010	Collars	325,000 Mmbtu/day	$5.55-$7.20	$ 51,534
2011	Collars	255,000 Mmbtu/day	$5.73-$6.83	$ 61,899
Crude Oil				
2010	Collars	1,000 bbls/day	$75.00-$93.75	$ 589
2011	Collars	5,244 bbls/day	$70.00-$90.00	$ (2,149)

Other Commodity Risk

We are impacted by basis risk, caused by factors that affect the relationship between commodity futures prices reflected in derivative commodity instruments and the cash market price of the underlying commodity. Natural gas transaction prices are frequently based on industry reference prices that may vary from prices experienced in local markets. If commodity price changes in one region are not reflected in other regions, derivative commodity instruments may no longer provide the expected hedge, resulting in increased basis risk. In addition to the collars detailed above, we have entered into basis swap agreements, which do not qualify for hedge accounting and are marked to market. The price we receive for our gas production can be less than the NYMEX price because of adjustments for delivery location (basis), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively fix the basis adjustments. The fair value of the basis swaps was a net realized pre-tax loss of $4.8 million at June 30, 2010.

The following table shows the fair value of our collars and the hypothetical change in the fair value that would result from a 10% and a 25% change in commodity prices at June 30, 2010 (in thousands):

		Hypothetical Change in Fair Value Increase of		Hypothetical Change in Fair Value Decrease of	
	Fair Value	10%	25%	10%	25%
Collars	$111,873	($72,069)	($172,207)	$75,081	$194,806

Interest rate risk. At June 30, 2010, we had $1.9 billion of debt outstanding. Of this amount, $1.4 billion bore interest at fixed rates averaging 7.4%. Senior bank debt totaling $475.0 million bore interest at floating rates averaging 2.2%. A 1% increase or decrease in short-term interest rates would affect interest expense by approximately $4.8 million per year.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Form 10-Q. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of June 30, 2010 at the reasonable assurance level.

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Changes in Internal Control over Financial Reporting

There was no change in our system of internal control over financial reporting (as defined in Rules 13a-15(f) and 15-d-15(f) under the Exchange Act) during the quarter ended June 30, 2010 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II OTHER INFORMATION
ITEM 1A. RISK FACTORS

We are subject to various risks and uncertainties in the course of our business. The following summarizes some, but not all, of the risks and uncertainties, which may adversely affect our business, financial condition or results of operations. Our business could also be impacted by additional risks and uncertainties not currently known to us or that we currently deem to be immaterial.

Risks Related to Our Business

Volatility of oil and gas prices significantly affects our cash flow and capital resources and could hamper our ability to produce oil and gas economically

Oil and gas prices are volatile, and a decline in prices adversely affects our profitability and financial condition. The oil and gas industry is typically cyclical, and prices for oil and gas have been volatile. Historically, the industry has experienced downturns characterized by oversupply and/or weak demand. Long-term supply and demand for oil and gas is uncertain and subject to a myriad of factors such as:

- the domestic and foreign supply of oil and gas;
- the price and availability of alternative fuels;
- weather conditions;
- the level of consumer demand;
- the price of foreign imports;
- worldwide economic conditions;
- the availability, proximity and capacity of transportation facilities and processing facilities;
- the effect of worldwide energy conservation efforts;
- political conditions in oil and gas producing regions; and
- domestic and foreign governmental regulations and taxes.

In July 2008, the average New York Mercantile Exchange (NYMEX) price of oil was $133.49 per barrel and the average NYMEX price of gas was $12.96 per mcf. In December 2008, the average NYMEX price of oil had fallen to $42.04 per barrel and gas was $6.56 per mcf. In 2009, oil prices rebounded to $74.60 per barrel as of December 31, 2009, while gas prices remained depressed at $4.46 per mcf. In June 2010, the average NYMEX price for oil was $75.40 per barrel and gas was $4.78 per mcf. Decreases in oil and gas prices have adversely affected our revenues, net income, cash flow and proved reserves. Significant price decreases could have a material adverse effect on our operations and limit our ability to fund capital expenditures. Without the ability to fund capital expenditures, we would be unable to replace reserves and production. Sustained decreases in oil and gas prices will further adversely affect our revenues, net income, cash flows, proved reserves and our ability to fund capital expenditures.

Information concerning our reserves and future net cash flow estimates is uncertain

There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and their values, including many factors beyond our control. Estimates of proved reserves are by their nature uncertain. Although we believe these estimates are reasonable, actual production, revenues and costs to develop will likely vary from estimates and these variances could be material.

Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of oil and gas that cannot be directly measured. As a result, different petroleum engineers, each using industry-accepted geologic and engineering practices and scientific methods, may calculate different estimates of reserves and future net cash flows based on the same available data. Because of the subjective nature of oil and gas reserve estimates, each of the following items may differ materially from the amounts or other factors estimated:

- the amount and timing of oil and gas production;
- the revenues and costs associated with that production; and
- the amount and timing of future development expenditures.

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The discounted future net cash flows from our proved reserves included in our 2009 Annual Report on Form 10-K should not be considered as the market value of the reserves attributable to our properties. As required by generally accepted accounting principles, the estimated discounted future net revenues from our proved reserves are based on a twelve month average price (beginning of month) while cost estimates are as of the end of the year. Actual future prices and costs may be materially higher or lower. In addition, the 10 percent discount factor that is required to be used to calculate discounted future net revenues for reporting purposes under generally accepted accounting principles is not necessarily the most appropriate discount factor based on the cost of capital in effect from time to time and risks associated with our business and the oil and gas industry in general.

If oil and gas prices decrease or drilling efforts are unsuccessful, we may be required to record write downs of our oil and gas properties

In the past we have been required to write down the carrying value of certain of our oil and gas properties, and there is a risk that we will be required to take additional writedowns in the future. Writedowns may occur when oil and gas prices are low, or if we have downward adjustments to our estimated proved reserves, increases in our estimates of operating or development costs, deterioration in our drilling results or mechanical problems with wells where the cost to redrill or repair is not supported by the expected economics.

Accounting rules require that the carrying value of oil and gas properties be periodically reviewed for possible impairment. Impairment is recognized for the excess of book value over fair value when the book value of a proven property is greater than the expected undiscounted future net cash flows from that property and on acreage when conditions indicate the carrying value is not recoverable. We may be required to write down the carrying value of a property based on oil and gas prices at the time of the impairment review, or as a result of continuing evaluation of drilling results, production data, economics and other factors. While an impairment charge reflects our long-term ability to recover an investment, it does not impact cash or cash flow from operating activities, but it does reduce our reported earnings and increases our leverage ratios.

Significant capital expenditures are required to replace our reserves

Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flow from operations, our bank credit facility and debt and equity issuances. From time to time, we have also engaged in asset monetization transactions. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of oil and gas and our success in developing and producing new reserves. If our access to capital were limited due to numerous factors, which could include a decrease in revenues due to lower gas and oil prices or decreased production or deterioration of the credit and capital markets, we would have a reduced ability to replace our reserves. We may not be able to incur additional bank debt, issue debt or equity, engage in asset monetization or access other methods of financing on an economic basis to meet our reserve replacement requirements.

The amount available for borrowing under our bank credit facility is subject to a borrowing base, which is determined by our lenders taking into account our estimated proved reserves and is subject to periodic redeterminations based on pricing models determined by the lenders at such time. The decline in oil and gas prices in 2008 has adversely impacted the value of our estimated proved reserves and, in turn, the market values used by our lenders to determine our borrowing base. If commodity prices (particularly gas prices) decline through the second half of 2010, it will have similar adverse effects on our reserves and borrowing base.

Our future success depends on our ability to replace reserves that we produce

Because the rate of production from oil and gas properties generally declines as reserves are depleted, our future success depends upon our ability to economically find or acquire and produce additional oil and gas reserves. Except to the extent that we acquire additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline as reserves are produced. Future oil and gas production, therefore, is highly dependent upon our level of success in acquiring or finding additional reserves that are economically recoverable. We cannot assure you that we will be able to find or acquire and develop additional reserves at an acceptable cost.

We acquire significant amounts of unproved property to further our development efforts. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire both producing and unproved properties as well as lease undeveloped acreage that we believe will enhance growth potential and increase our earnings over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our initial investments. Additionally, there can be no assurance that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

Our indebtedness could limit our ability to successfully operate our business

We are leveraged and our exploration and development program will require substantial capital resources depending on the level of drilling and the expected cost of services. Our existing operations will also require ongoing capital expenditures. In addition, if we decide to pursue additional acquisitions, our capital expenditures will increase, both to complete such acquisitions and to explore and develop any newly acquired properties.

The degree to which we are leveraged could have other important consequences, including the following:

- we may be required to dedicate a substantial portion of our cash flows from operations to the payment of our indebtedness, reducing the funds available for our operations;
- a portion of our borrowings are at variable rates of interest, making us vulnerable to increases in interest rates;
- we may be more highly leveraged than some of our competitors, which could place us at a competitive disadvantage;
- our degree of leverage may make us more vulnerable to a downturn in our business or the general economy;
- we are subject to numerous financial and other restrictive covenants contained in our existing credit agreements the breach of which could materially and adversely impact our financial performance;
- our debt level could limit our flexibility to grow the business and in planning for, or reacting to, changes in our business and the industry in which we operate; and
- we may have difficulties borrowing money in the future.

Despite our current levels of indebtedness, we still may be able to incur substantially more debt. This could further increase the risks described above. In addition to those risks above, we may not be able to obtain funding on acceptable terms.

Our business is subject to operating hazards that could result in substantial losses or liabilities that may not be fully covered under our insurance policies

Oil and gas operations are subject to many risks, including well blowouts, craterings, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, formations with abnormal pressures, pipeline ruptures or spills, pollution, releases of toxic natural gas and other environmental hazards and risks. If any of these hazards occur, we could sustain substantial losses as a result of:

- injury or loss of life;
- severe damage to or destruction of property, natural resources and equipment;
- pollution or other environmental damage;

- clean-up responsibilities;
- regulatory investigations and penalties; or
- suspension of operations.

We maintain insurance against some, but not all, of these potential risks and losses. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. We have experienced substantial increases in premiums, especially in areas affected by hurricanes and tropical storms. Insurers have imposed revised limits affecting how much the insurers will pay on actual storm claims plus the cost to re-drill wells where substantial damage has been incurred. Insurers are also requiring us to retain larger deductibles and reducing the scope of what insurable losses will include. Even with the increase in future insurance premiums, coverage will be reduced, requiring us to bear a greater potential risk if our oil and gas properties are damaged. We do not maintain any business interruption insurance. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs that is not fully covered by insurance, it could have a material adverse affect on our financial condition and results of operations.

We are subject to financing and interest rate exposure risks

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in our credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. For example, at June 30, 2010, approximately 74% of our debt is at fixed interest rates with the remaining 26% subject to variable interest rates.

Recent and continuing disruptions and volatility in the global finance markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital; a significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results. We are exposed to some credit risk related to our senior credit facility to the extent that one or more of our lenders may be unable to provide necessary funding to us under our existing revolving line of credit if it experiences liquidity problems.

Difficult conditions in the global capital markets, the credit markets and the economy generally may materially adversely affect our business and results of operations

Global financial markets have been, and continue to be, disrupted and volatile and economic conditions remain weak. As a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of accessing the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards and limited the amount of funding available to borrowers. As a result, we may be unable to obtain adequate funding under our current credit facility because (i) our lending counterparties may be unwilling or unable to meet their funding obligations or (ii) the amount we may borrow under our current credit facility could be reduced as a result of lower oil, natural gas liquids or gas prices, declines in reserves, stricter lending requirements or regulations, or for other reasons.

Due to these factors, we cannot be certain that funding will be available on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to implement our business plans or otherwise take advantage of business opportunities or respond to competitive pressures any of which could have a material adverse effect on our production, revenues and results of operations.

Hedging transactions may limit our potential gains and involve other risks

To manage our exposure to price risk, we, from time to time, enter into hedging arrangements, utilizing commodity derivatives with respect to a significant portion of our future production. The goal of these hedges is to lock in prices so as to limit volatility and increase the predictability of cash flow. These transactions limit our potential gains if oil and gas prices rise above the price established by the hedge.

In addition, hedging transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;

- the counterparties to our futures contracts fail to perform under the contracts; or

- an event materially impacts oil or gas prices or the relationship between the hedged price index and the oil and gas sales price.

We cannot assure you that any hedging transactions we may enter into will adequately protect us from declines in the prices of oil and gas. On the other hand, where we choose not to engage in hedging transactions in the future, we may be more adversely affected by changes in oil and gas prices than our competitors who engage in hedging transactions.

Many of our current and potential competitors have greater resources than we have and we may not be able to successfully compete in acquiring, exploring and developing new properties

We face competition in every aspect of our business, including, but not limited to, acquiring reserves and leases, obtaining goods, services and employees needed to operate and manage our business and marketing oil and gas. Competitors include multinational oil companies, independent production companies and individual producers and operators. Many of our competitors have greater financial and other resources than we do. As a result, these

competitors may be able to address these competitive factors more effectively than we can or weather industry downturns more easily than we can.

The demand for field services and their ability to meet that demand may limit our ability to drill and produce our oil and natural gas properties

In a rising price environment, such as those experienced in 2007 and early 2008, well service providers and related equipment and personnel are in short supply. This caused escalating prices, the possibility of poor services coupled with potential damage to downhole reservoirs and personnel injuries. Such pressures increase the actual cost of services, extend the time to secure such services and add costs for damages due to accidents sustained from the over use of equipment and inexperienced personnel. In some cases, we are operating in areas where services and infrastructure are limited, or do not exist or in urban areas which are more restrictive.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase

Section 1(b) of the Natural Gas Act of 1938 (NGA) exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission (FERC) as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline s status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts, or Congress.

While our natural gas gathering operations are generally exempt from FERC regulation under the NGA, our gas gathering operations may be subject to certain FERC reporting and posting requirements in a given year. FERC has recently issued a final rule requiring certain participants in the natural gas market, including certain gathering facilities and natural gas marketers that engage in a minimum level of natural gas sales or purchases, to submit annual reports to FERC on the aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to, the formation of price indices. In addition, FERC has issued a final rule requiring major non-interstate pipelines, defined as certain non-interstate pipelines delivering more than an average of 50 million MMBtu of gas over the previous three calendar years, to post daily certain information regarding the pipeline s capacity and scheduled flows for each receipt and delivery point that has design capacity equal to or greater than 15,000 MMBtu per day.

Other FERC regulations may indirectly impact our businesses and the markets for products derived from these businesses. FERC s policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on open access transportation, gas quality, ratemaking, capacity release and market center promotion, may indirectly affect the intrastate natural gas market. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that FERC will continue this approach as it considers matters such as pipelines rates and rules and policies that may affect rights of access to transportation capacity. For more information regarding the regulation of our operations, please see Government Regulation in Item 1 of our 2009 Annual Report on Form 10-K.

Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines

Under the Energy Policy Act of 2005 FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation. While our operations have not been regulated as a natural gas company by FERC under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdiction facilities to FERC annual reporting and daily scheduled flow and capacity posting requirements. We also must comply with the anti-market manipulation rules enforced by FERC. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject Range to civil penalty liability. For more information regarding regulation of our operations, please see Government Regulation in Item 1 of our 2009 Annual Report on Form 10-K.

The oil and gas industry is subject to extensive regulation

The oil and gas industry is subject to various types of regulations in the United States by local, state and federal agencies. Legislation affecting the industry is under constant review for amendment or expansion, frequently increasing our regulatory burden. Numerous departments and agencies, both state and federal, are authorized by statute to issue rules and regulations binding on participants in the oil and gas industry. Compliance with such rules and regulations often increases our cost of doing business, delays our operations and, in turn, decreases our profitability.

Our operations are subject to numerous and increasingly strict federal, state and local laws, regulations and enforcement policies relating to the environment. We may incur significant costs and liabilities in complying with existing or future environmental laws, regulations and enforcement policies and may incur costs arising out of property damage or injuries to employees and other persons. These costs may result from our current and former operations and even may be caused by previous owners of property we own or lease or relate to third party sites. Any past, present or future failure by us to completely comply with environmental laws, regulations and enforcement policies could cause us to incur substantial fines, sanctions or liabilities from cleanup costs or other damages. Incurrence of those costs or damages could reduce or eliminate funds available for exploration, development or acquisitions or cause us to incur losses.

Climate change is receiving increasing attention from scientists, legislators and governmental agencies. There is an ongoing debate as to the extent to which our climate is changing, the potential causes of this change and its potential impacts. Some attribute global warming to increased levels of greenhouse gases, including carbon dioxide and methane, which has led to significant legislative and regulatory efforts to limit greenhouse gas emissions.

There are a number of legislative and regulatory proposals to address greenhouse gas emissions, which are in various phases of discussion or implementation. The outcome of federal and state actions to address global climate change could result in a variety of regulatory programs including potential new regulations to control or restrict emissions, taxes or other charges to deter emissions of greenhouse gases, energy efficiency requirements to reduce demand, or other regulatory actions. These actions could:

- result in increased costs associated with our operations;
- increase other costs to our business;
- affect the demand for natural gas, and
- impact the prices we charge our customers.

An adoption of federal or state requirements mandating a reduction in greenhouse gas emissions could have far-reaching and significant impacts on the energy industry and the U.S. economy. We cannot predict the potential impact of such laws or regulations on our future consolidated financial condition, results of operations or cash flows.

For more information regarding the environmental regulation of our business, see Environment and Occupational Matters in Item 1 of our Annual Report on Form 10-K.

Certain federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated, and additional state taxes on natural gas extraction may be imposed, as a result of future legislation.

Among the changes contained in President Obama s budget proposal for fiscal year 2011, released by the White House on February 1, 2010, is the elimination of certain U.S. federal income tax benefits currently available to oil and gas exploration and production companies. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective. As of December 31, 2009, we had a tax basis of $526 million related to prior year capitalized intangible drilling costs, which will be amortized over the next five years.

The passage of any legislation as a result of the budget proposal or any other similar change in U.S. federal income tax law could eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition and results of operation.

In addition, Pennsylvania Governor Ed Rendell s budget proposal for fiscal year 2011, released on February 9, 2009, proposed a new natural gas wellhead tax on both volumes and sales of natural gas extracted in Pennsylvania, where the majority of our acreage in the Marcellus Shale is located. The passage of any legislation as a result of the Pennsylvania state budget proposal could increase the tax burden on our operations in the Marcellus Shale.

Acquisitions are subject to the risks and uncertainties of evaluating reserves and potential liabilities and may be disruptive and difficult to integrate into our business

We could be subject to significant liabilities related to our acquisitions. It generally is not feasible to review in detail every individual property included in an acquisition. Ordinarily, a review is focused on higher valued properties. However, even a detailed review of all properties and records may not reveal existing or potential problems in all of the properties, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. We do not always inspect every well we acquire, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is performed.

In addition, there is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our acquisition strategy is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Our ability to pursue our acquisition strategy may be hindered if we are unable to obtain financing on terms acceptable to us or regulatory approvals.

Acquisitions often pose integration risks and difficulties. In connection with recent and future acquisitions, the process of integrating acquired operations into our existing operations may result in unforeseen operating difficulties and may require significant management attention and financial resources that would otherwise be available for the ongoing development or expansion of existing operations. Future acquisitions could result in our incurring additional debt, contingent liabilities, expenses and diversion of resources, all of which could have a material adverse effect on our financial condition and operating results.

Our success depends on key members of our management and our ability to attract and retain experienced technical and other professional personnel

Our success is highly dependent on our management personnel and none of them is currently subject to an employment contract. The loss of one or more of these individuals could have a material adverse effect on our business. Furthermore, competition for experienced technical and other professional personnel is intense. If we cannot retain our current personnel or attract additional experienced personnel, our ability to compete could be adversely affected. Also, the loss of experienced personnel could lead to a loss of technical expertise.

Drilling is a high-risk activity

The cost of drilling, completing, and operating a well is often uncertain, and many factors can adversely affect the economics of a well. Our efforts will be uneconomical if we drill dry holes or wells that are productive but do not produce enough oil and gas to be commercially viable after drilling, operating and other costs. Furthermore, our drilling and producing operations may be curtailed, delayed, or canceled as a result of other factors, including:

- high costs, shortages or delivery delays of drilling rigs, equipment, labor, or other services;
- unexpected operational events and drilling conditions;
- reductions in oil and gas prices;
- limitations in the market for oil and gas;
- adverse weather conditions;
- facility or equipment malfunctions;
- equipment failures or accidents;
- title problems;

pipe or cement failures;

casing collapses;

compliance with environmental and other governmental requirements;

environmental hazards, such as natural gas leaks, oil spills, pipelines ruptures, and discharges of toxic gases;

lost or damaged oilfield drilling and service tools;

unusual or unexpected geological formations;

loss of drilling fluid circulation;

pressure or irregularities in formations;

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- fires;
- natural disasters;
- surface craterings and explosions; and
- uncontrollable flows of oil, natural gas or well fluids.

If any of these factors were to occur with respect to a particular field, we could lose all or a part of our investment in the field, or we could fail to realize the expected benefits from the field, either of which could materially and adversely affect our revenue and profitability.

New technologies may cause our current exploration and drilling methods to become obsolete

The oil and gas industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. One or more of the technologies that we currently use or that we may implement in the future may become obsolete. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are unable to maintain technological advancements consistent with industry standards, our operations and financial condition may be adversely affected.

New legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate hydrocarbon (natural gas and oil) production. We find that the use of hydraulic fracturing is necessary to produce commercial quantities of natural gas and oil from many reservoirs, especially shale formations such as the Barnett Shale and the Marcellus Shale. The U.S. Environmental Protection Agency, or the EPA, has commenced a study of the potential environmental impacts of hydraulic fracturing, including the impact on drinking water sources and public health, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. Legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states have and others are considering adopting regulations that could restrict hydraulic fracturing in certain circumstances. Any new laws, regulation or permitting requirements regarding hydraulic fracturing could lead to operational delay, or increased operating costs or third party or governmental claims, and could result in additional burdens that could increase our costs of compliance and doing business as well as delay the development of unconventional gas resources from shale formations which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Our business depends on oil and gas transportation and processing facilities, most of which are owned by others

The marketability of our oil and gas production depends in part on the availability, proximity and capacity of pipeline systems and processing facilities owned by third parties. The lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Although we have some contractual control over the transportation of our product, material changes in these business relationships could materially affect our operations. We generally do not purchase firm transportation on third party facilities and therefore, our production transportation can be interrupted by those having firm arrangements. We have recently entered into some firm arrangements in certain of our production areas. We have also entered into long-term agreements with third parties to provide natural gas gathering and processing services in the Marcellus Shale. Federal and state regulation of oil and gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and gas. If any of these third party pipelines and other facilities become partially or fully unavailable to transport or process our product, or if the natural gas quality specifications for a natural gas pipeline or facility changes so as to restrict our ability to transport natural gas on those pipelines or facilities, our revenues could be adversely affected.

The disruption of third-party facilities due to maintenance and/or weather could negatively impact our ability to market and deliver our products. In particular, the disruption of certain third-party natural gas processing facilities in the Marcellus Shale could materially affect our ability to market and deliver natural gas production in that area. We have no control over when or if such facilities are restored and generally have no control over what prices will be charged. A total shut-in of production could materially affect us due to a lack of cash flow, and if a substantial portion of the production is hedged at lower than market prices, those financial hedges would have to be paid from borrowings absent sufficient cash flow.

Any failure to meet our debt obligations could harm our business, financial condition and results of operations

If our cash flow and capital resources are insufficient to fund our debt obligations, we may be forced to sell assets, seek additional equity or restructure our debt. In addition, any failure to make scheduled payments of interest and principal on our outstanding indebtedness would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness on acceptable terms. Our cash flow and capital resources may be insufficient for payment of interest on and principal of our debt in the future and any such alternative measures may be unsuccessful or may not permit us to meet scheduled debt service obligations, which could cause us to default on our obligations and impair our liquidity.

We exist in a litigious environment

Any constituent could bring suit regarding our existing or planned operations or allege a violation of an existing contract. Any such action could delay when planned operations can actually commence or could cause a halt to existing production until such alleged violations are resolved by the courts. Not only could we incur significant legal and support expenses in defending our rights, but halting existing production or delaying planned operations could impact our future operations and financial condition. Such legal disputes could also distract management and other personnel from their primary responsibilities.

Our financial statements are complex

Due to United States generally accepted accounting rules and the nature of our business, our financial statements continue to be complex, particularly with reference to hedging, asset retirement obligations, equity awards, deferred taxes and the accounting for our deferred compensation plans. We expect such complexity to continue and possibly increase.

Risks Related to Our Common Stock

Common stockholders will be diluted if additional shares are issued

In 2004, 2005 and 2006, we sold 40.2 million shares of common stock to finance acquisitions. In 2007, we sold 8.1 million shares of common stock to finance acquisitions. In 2008, we sold 4.4 million shares of common stock with the proceeds used to pay down a portion of the outstanding balance of our bank credit facility. In 2009, we issued 744,000 shares of common stock to purchase acreage in the Marcellus Shale. Our ability to repurchase securities for cash is limited by our bank credit facility and our senior subordinated note agreements. We also issue restricted stock and stock appreciation rights to our employees and directors as part of their compensation. In addition, we may issue additional shares of common stock, additional subordinated notes or other securities or debt convertible into common stock, to extend maturities or fund capital expenditures, including acquisitions. If we issue additional shares of our common stock in the future, it may have a dilutive effect on our current outstanding stockholders.

Dividend limitations

Limits on the payment of dividends and other restricted payments, as defined, are imposed under our bank credit facility and under our senior subordinated note agreements. These limitations may, in certain circumstances, limit or prevent the payment of dividends independent of our dividend policy.

Our stock price may be volatile and you may not be able to resell shares of our common stock at or above the price you paid

The price of our common stock fluctuates significantly, which may result in losses for investors. The market price of our common stock has been volatile. From January 1, 2007 to June 30, 2010, the price of our common stock reported by the New York Stock Exchange ranged from a low of $23.77 per share to a high of $76.81 per share. We expect our stock to continue to be subject to fluctuations as a result of a variety of factors, including factors beyond our control. These factors include:

- changes in oil and gas prices;
- variations in quarterly drilling, recompletions, acquisitions and operating results;
- changes in governmental regulation;
- changes in financial estimates by securities analysts;

- changes in market valuations of comparable companies;
- additions or departures of key personnel; or
- future sales of our stock.

We may fail to meet expectations of our stockholders or of securities analysts at some time in the future and our stock price could decline as a result.

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ITEM 6. Exhibits
(a) EXHIBITS

Exhibit Number	Exhibit Description
3.1	Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on May 5, 2004, as amended by the Certificate of Second Amendment to Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on July 28, 2005) and the Certificate of Second Amendment to the Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on July 24, 2008)
3.2	Amended and Restated By-laws of Range (incorporated by reference to Exhibit 3.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 20, 2010)
31.1*	Certification by the Chairman and Chief Executive Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification by the Chief Financial Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Certification by the Chairman and Chief Executive Officer of Range Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification by the Chief Financial Officer of Range Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101. INS**	XBRL Instance Document
101. SCH**	XBRL Taxonomy Extension Schema
101. CAL**	XBRL Taxonomy Extension Calculation Linkbase Document
101. LAB**	XBRL Taxonomy Extension Label Linkbase Document
101. PRE**	XBRL Taxonomy Extension Presentation Linkbase Document

* filed herewith

** furnished herewith

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SIGNATURES

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

Date: July 26, 2010

RANGE RESOURCES CORPORATION

By: /s/ ROGER S. MANNY

Roger S. Manny

Executive Vice President and Chief Financial Officer

Date: July 26, 2010

RANGE RESOURCES CORPORATION

By: /s/ DORI A. GINN

Dori A. Ginn

Principal Accounting Officer and Vice President Controller

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