RANGE RESOURCES CORP
Form 10-Q
October 28, 2010

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 September 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. (Check one):

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

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

Yes o No þ

160,071,797 Common Shares were outstanding on October 25, 2010.

RANGE RESOURCES CORPORATION
FORM 10-Q
Quarter Ended September 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)

	September 30, 2010 (Unaudited)	December 31, 2009
Assets		
Current assets:		
Cash and equivalents	$ 2,078	$ 767
Accounts receivable, less allowance for doubtful accounts of $1,386 and $2,176	97,601	123,622
Deferred tax asset		8,054
Unrealized derivative gain	153,585	21,545
Inventory and other	23,699	21,292
Total current assets	276,963	175,280
Unrealized derivative gain	46,412	4,107
Equity method investments	152,269	146,809
Natural gas and oil properties, successful efforts method	6,748,261	6,308,707
Accumulated depletion and depreciation	(1,553,257)	(1,409,888)
	5,195,004	4,898,819
Transportation and field assets	137,586	161,034
Accumulated depreciation and amortization	(58,837)	(69,199)
	78,749	91,835
Other assets	87,768	79,031
Total assets	$ 5,837,165	$ 5,395,881
Liabilities		
Current liabilities:		
Accounts payable	$ 232,332	$ 214,548
Asset retirement obligations	2,446	2,446
Accrued liabilities	66,011	58,585
Deferred tax liability	36,038	
Accrued interest	39,863	24,037
Unrealized derivative loss	1,957	14,488
Total current liabilities	378,647	314,104
Bank debt	165,000	324,000

Subordinated notes		1,686,260		1,383,833
Deferred tax liability		842,228		776,965
Unrealized derivative loss				271
Deferred compensation liability		116,601		135,541
Asset retirement obligations and other liabilities		73,159		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, 160,062,048 issued at September 30, 2010 and 158,336,264 issued at December 31, 2009		1,600		1,583
Common stock held in treasury, 210,269 shares at September 30, 2010 and 217,327 shares at December 31, 2009		(7,716)		(7,964)
Additional paid-in capital		1,815,576		1,772,020
Retained earnings		665,822		606,529
Accumulated other comprehensive income		99,988		6,421
Total stockholders equity		2,575,270		2,378,589
Total liabilities and stockholders equity	$	5,837,165	$	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 September 30,		Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
Revenues and other income				
Natural gas, NGL and oil sales	$ 219,560	$ 202,122	$ 663,104	$ 597,834
Transportation and gathering	(1,634)	2,444	1,133	4,091
Derivative fair value income (loss)	9,981	(482)	58,860	65,209
Gain on the sale of assets	67	32	79,111	39
Other	(1,013)	(475)	(1,951)	(6,663)
Total revenues and other income	226,961	203,641	800,257	660,510
Costs and expenses				
Direct operating	34,287	31,111	95,102	101,480
Production and ad valorem taxes	8,873	7,600	25,033	23,421
Exploration	15,236	10,902	44,344	35,609
Abandonment and impairment of unproved properties	20,534	24,053	46,438	84,579
General and administrative	36,523	29,928	100,529	83,941
Termination costs		840	7,938	840
Deferred compensation plan	(5,347)	16,445	(25,194)	29,635
Interest expense	33,806	30,633	94,872	86,817
Loss on early extinguishment of debt	5,351		5,351	
Depletion, depreciation and amortization	91,768	97,208	271,391	270,241
Impairment of proved properties			6,505	
Total costs and expenses	241,031	248,720	672,309	716,563
(Loss) income from operations	(14,070)	(45,079)	127,948	(56,053)
Income tax (benefit) expense				
Current	(10)	(695)	(10)	(76)
Deferred	(5,892)	(14,566)	49,495	(18,884)
Total income tax (benefit) expense	(5,902)	(15,261)	49,485	(18,960)
Net (loss) income	$ (8,168)	$ (29,818)	$ 78,463	$ (37,093)
(Loss) income per common share:				
Basic	$ (0.05)	$ (0.19)	$ 0.49	$ (0.24)

Diluted	$ (0.05)	$ (0.19)	$ 0.49	$ (0.24)
Dividends per common share	$ 0.04	$ 0.04	$ 0.12	$ 0.12
Weighted average common shares outstanding:				
Basic	157,109	154,653	156,777	154,257
Diluted	157,109	154,653	158,493	154,257

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)

	Nine Months Ended September 30,	
	2010	**2009**
Operating activities:		
Net income (loss)	$ 78,463	$ (37,093)
Adjustments to reconcile net cash provided from operating activities:		
Loss from equity method investments	1,830	6,548
Deferred income tax expense (benefit)	49,495	(18,884)
Depletion, depreciation, amortization and proved property impairment	277,896	270,241
Exploration dry hole costs	1,661	342
Mark-to-market (gain) loss on gas and oil derivatives not designated as hedges	(23,885)	83,393
Abandonment and impairment of unproved properties	46,438	84,579
Unrealized derivative (gain) loss	(2,400)	483
Deferred and stock-based compensation	10,313	58,844
Amortization of deferred financing costs and other	8,891	6,441
Gain on sale of assets	(79,111)	(39)
Changes in working capital:		
Accounts receivable	10,279	38,373
Inventory and other	(2,407)	(807)
Accounts payable	12,365	(67,076)
Accrued liabilities and other	9,040	18,423
Net cash provided from operating activities	398,868	443,768
Investing activities:		
Additions to oil and gas properties	(589,753)	(425,376)
Additions to field service assets	(12,284)	(21,959)
Acreage and proved property purchases	(249,731)	(118,724)
Additions to equity method investment		(6,099)
Other assets	(45)	8,604
Proceeds from disposal of assets	327,454	182,230
Purchase of marketable securities held by the deferred compensation plan	(16,399)	(6,932)
Proceeds from the sales of marketable securities held by the deferred compensation plan	14,943	3,155
Net cash used in investing activities	(525,815)	(385,101)
Financing activities:		
Borrowing on credit facilities	784,000	582,000
Repayment on credit facilities	(943,000)	(877,000)
Dividends paid	(19,170)	(18,843)
Issuance of common stock	5,904	8,368

Issuance of subordinated notes	500,000	285,201
Repayment of subordinated notes	(202,458)	
Debt issuance costs	(9,435)	(6,399)
Change in cash overdrafts	7,609	(37,690)
Proceeds from the sales of common stock held by the deferred compensation plan	4,808	6,049
Purchases of common stock held by the deferred compensation plan		(247)
Net cash provided from (used in) financing activities	128,258	(58,561)
Increase in cash and equivalents	1,311	106
Cash and equivalents at beginning of period	767	753
Cash and equivalents at end of period	$ 2,078	$ 859

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 September 30,		Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
Net (loss) income	$ (8,168)	$ (29,818)	$ 78,463	$ (37,093)
Other comprehensive (loss) income:				
Realized gain on hedge derivative contract settlements reclassified into earnings from other comprehensive income, net of taxes	(9,602)	(34,248)	(21,726)	(100,070)
Change in unrealized deferred hedging gains (losses), net of taxes	66,968	(1,218)	115,293	41,965
Total comprehensive income (loss)	$ 49,198	$ (65,284)	$ 172,030	$ (95,198)

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

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RANGE RESOURCES CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

(1) ORGANIZATION AND NATURE OF BUSINESS

We are a Fort Worth, Texas-based independent natural gas company engaged in the exploration, development and acquisition of primarily natural gas properties in the Southwestern and the Appalachian regions of the United States. Our objective is to build stockholder value through consistent growth in reserves and production on a cost-efficient basis. 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.

Certain reclassifications have been made to the presentation of prior periods to conform to the current year presentation, which includes the reclassification of severance costs associated with the closing of our Houston office from exploration expense ($200,000) and general and administrative expense ($640,000) to termination costs included in the accompanying consolidated statement of operations.

(3) NEW ACCOUNTING STANDARDS

Recently Adopted

Accounting standards for variable interest entities were amended by the Financial Accounting Standards Board (the FASB) in September 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 roll forward of Level 3 activity, and (4) the transfers in and out of Levels 1 and 2. We adopted all aspects of this standard in 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 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 had an effective date of January 1, 2010, and consequently

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operating net revenues after January 1, 2010 were a downward adjustments to the selling price. The proceeds we received were placed in a like-kind exchange account and in June 2010 we used a portion of the proceeds to purchase proved and unproved natural gas properties in Virginia. In September 2010, the like-kind exchange account was closed and the balance of these proceeds ($135.0 million) was used to repay amounts outstanding under our bank credit facility.

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 natural gas and oil properties included in our consolidated balance sheets, 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 natural gas and oil properties included in our consolidated balance sheets, 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 and additional leasehold evaluations. We used proceeds from our like-kind exchange account to fund this acquisition (see 2010 Asset Sales above).

(5) INCOME TAXES

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Income tax (benefit) expense	$(5,902)	$(15,261)	$49,485	$(18,960)
Effective tax rate	(41.9%)	(33.9%)	38.7%	(33.8%)

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 and the nine months ended September 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. The three months and the nine months ended September 30, 2010 include a tax benefit for the release of valuation allowances reserved for capital losses. The three months and the nine months ended September 30, 2009 includes additional tax expense to increase valuation allowances.

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(6) (LOSS) INCOME PER COMMON SHARE

Basic net (loss) income per share attributable to common shareholders is computed as (i) net (loss) income (ii) less income allocable to participating securities (iii) divided by weighted average basic shares outstanding. Diluted net (loss) income per share attributable to common shareholders is computed as (i) basic net (loss) income 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 (loss) income to basic net (loss) income attributable to common shareholders and to diluted net (loss) income 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 September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Numerator:				
Net (loss) income	$ (8,168)	$ (29,818)	$ 78,463	$ (37,093)
Less: Basic income allocable to participating securities [(a)]			(1,379)	
Basic net (loss) income attributable to common shareholders	(8,168)	(29,818)	77,084	(37,093)
Diluted adjustments to income allocable to participating securities [(a)]			11	
Diluted net (loss) income attributable to common shareholders	$ (8,168)	$ (29,818)	$ 77,095	$ (37,093)
Denominator:				
Weighted average common shares outstanding basic	157,109	154,653	156,777	154,257
Effect of dilutive securities:				
Employee stock options, SARs and stock held in the deferred compensation plan			1,716	
Weighted average common shares diluted	157,109	154,653	158,493	157,257
(Loss) income per common share:				
Basic net (loss) income	$ (0.05)	$ (0.19)	$ 0.49	$ (0.24)
Diluted net (loss) income	$ (0.05)	$ (0.19)	$ 0.49	$ (0.24)

(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 September 30, 2010 excludes 2.9 million shares of restricted stock compared to 2.8 million shares of restricted stock excluded at September 30, 2009 which are held in our deferred compensation plans (although all restricted stock is issued and outstanding upon grant). Weighted average common shares basic for the nine months ended September 30, 2010 excludes 2.8 million of shares of restricted stock compared to 2.5 million shares of restricted stock excluded for the nine months ended September 30, 2009. Stock appreciation rights (SARs) of 2.0 million for the nine months ended September 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. Due to our net loss from operations for the three months ended September 30, 2010 and the three months and the nine months ended September 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.

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(7) SUSPENDED EXPLORATORY WELL COSTS

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

	September 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	16,948	26,216
Reclassifications based on determination of proved reserves	(24,041)	(52,849)
Capitalized exploratory well costs charged to expense		(1,938)
Balance at end of period	11,959	19,052
Less exploratory well costs that have been capitalized for a period of one year or less	(5,834)	(10,778)
Capitalized exploratory well costs that have been capitalized for a period greater than one year	$ 6,125	$ 8,274
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	4	6

The $12.0 million of capitalized exploratory well costs at September 30, 2010 was incurred in 2010 ($5.8 million), in 2009 ($4.0 million) and in 2008 ($2.2 million). Of the four 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 September 30, 2010 is shown parenthetically). No interest expense was capitalized during the three months or the nine months ended September 30, 2010 and 2009.

	September 30, 2010	December 31, 2009
Bank debt (2.3%)	$ 165,000	$ 324,000
Subordinated debt:		
7.375% Senior Subordinated Notes due 2013, net of discount		198,362
6.375% Senior Subordinated Notes due 2015	150,000	150,000
7.5% Senior Subordinated Notes due 2016, net of discount	249,671	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	286,589	285,834
6.75% Senior Subordinated Notes due 2020	500,000	
Total debt	$ 1,851,260	$ 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 September 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 October 8, 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 with no one bank holding more than 5% 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 September 30, 2010, the outstanding balance under the bank credit facility was $165.0 million and we had $5.4 million of undrawn letters of credit leaving $1.1 billion 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 2.3% for the three months ended September 30, 2010 compared to 2.2% for the three months ended September 30, 2009. The weighted average interest rate on the bank credit facility was 2.2% for the nine months ended September 30, 2010 compared to 2.5% for the nine months ended September 30, 2009. A commitment fee is paid on the undrawn balance based on an annual rate of between 0.375% and 0.50%. At September 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 October 25, 2010, the interest rate (including applicable margin) was 2.2%.

Senior Subordinated Notes

In August 2010, we issued $500.0 million aggregate principal amount of 6.75% senior subordinated notes due 2020 (6.75% Notes) for net proceeds after underwriting discounts and commissions of $491.3 million. The 6.75% Notes were issued at par. Interest on the 6.75% Notes is payable semi-annually in February and August and is guaranteed by substantially all of our subsidiaries. We may redeem the 6.75% Notes, in whole or in part, at any time on or after August 1, 2015, at redemption prices of 103.375% of the principal amount as of August 1, 2015 declining to 100.0% on August 1, 2018 and thereafter. Before August 1, 2013, we may redeem up to 35% of the original aggregate principal amount of the 6.75% Notes at a redemption price equal to 106.75% 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 6.75% 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. We used $287.1 million of the proceeds to repay outstanding borrowings under our credit facility and $204.2 million to redeem our 7.375% senior subordinated notes due 2013.

In August 2010, we redeemed our 7.375% senior subordinated notes due 2013 at a redemption price equal to 101.229%. We recorded a loss on extinguishment of debt of $5.4 million including the transaction call premium costs as well as the expensing of related deferred financing cost on the repurchased debt.

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 September 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 September 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 nine months ended September 30, 2010 is as follows (in thousands):

	Nine Months Ended September 30, 2010
Beginning of period	$ 78,812

Liabilities incurred		1,233
Acquisitions		556
Liabilities settled		(1,646)
Liabilities sold		(12,891)
Accretion expense		4,139
Change in estimate		
End of period	$	70,203

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Accretion expense is recognized as a component of depreciation, depletion and amortization expense on our consolidated statements 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:

	Nine Months Ended September 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	940,428	1,384,861
Restricted stock grants	405,127	413,353
Treasury shares issued	7,058	16,573
Shares issued for acreage purchases	380,229	743,737
Ending balance	159,851,779	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.

(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. We typically utilize commodity derivative 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. Historically, our derivative activities have consisted of collars and fixed price swaps. In September 2010, we entered into call option derivative contracts under which we sold call options on crude oil in exchange for a cash premium received from the counterparty. At the time of settlement of these monthly call options, if the market price exceeds the fixed price of the call option, we will pay the counterparty such excess and if the market prices settles below the fixed price of the call option, no payment is due from either party. We do not utilize complex derivatives such as swaptions, knockouts or extendable swaps. At September 30, 2010, we had collars covering 209.5 Bcf of gas at weighted average floor and cap prices of $5.55 to $6.56 per mcf and 0.8 million barrels of oil at weighted average floor and cap prices of $70.56 to $81.54 per barrel. At September 30, 2010, we had sold call options for 3.1 million barrels of oil at a weighted average price of $81.77. The fair value of these commodity derivatives, 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 September 30, 2010, was a net unrealized pre-tax gain of $201.0 million. These contracts expire monthly through December 2012. We currently have not entered into any natural gas liquids (NGLs) derivative contracts.

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

Period	Contract Type	Volume Hedged	Average Hedge Price
Natural Gas			
2010	Collars	335,000 Mmbtu/day	$5.56-$7.20
2011	Collars	408,200 Mmbtu/day	$5.56-$6.48
2012	Collars	80,993 Mmbtu/day	$5.50-$6.25

Crude Oil			
2010	Collars	1,000 bbls/day	$75.00-$93.75
2012	Collars	2,000 bbls/day	$70.00-$80.00
2011	Call options	5,500 bbls/day	$80.00
2012	Call options	3,000 bbls/day	$85.00

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Every derivative instrument is recorded on our consolidated balance sheets 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) in the stockholders equity section of the accompanying consolidated balance sheets, which is later transferred to natural gas, NGL and oil sales when the underlying physical transaction occurs and the hedging contract is settled. Amounts included in AOCI at September 30, 2010 and December 31, 2009 relate solely to our commodity derivative activities. As of September 30, 2010, an unrealized pre-tax derivative gain of $162.6 million was recorded in AOCI. This gain is expected to be reclassified into earnings as a $27.5 million gain in 2010, a $127.8 million gain in 2011 and a $7.3 million gain in 2012. 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 natural gas, NGL and oil sales in the period the hedged production is sold. Natural gas, NGL and oil sales include $15.6 million of gains in the three months ended September 30, 2010 compared to gains of $54.4 million in the same period of 2009 related to settled hedging transactions. Natural gas, NGL and oil sales include $35.2 million of gains in the nine months ended September 30, 2010 compared to gains of $158.8 million in the nine months ended September 30, 2009 related to settled hedging transactions. Any ineffectiveness associated with these hedge derivatives is included in derivative fair value income (loss) in the accompanying consolidated statements 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 three months ended September 30, 2010 includes ineffective gains (unrealized and realized) of $2.4 million compared to gains of $1.2 million in the same period of 2009. The nine months ended September 30, 2010 includes ineffective gains (unrealized and realized) of $2.0 million compared to gains of $2.7 million in the same period of 2009.

Through September 30, 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 natural gas, NGL and oil 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 in derivative fair value income (loss) in the accompanying consolidated statements of operations. During the first nine months of 2010, there were no gains or losses recorded due to the discontinuance of hedge accounting treatment for these derivatives. During the first nine months of 2009, there were gains of $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 natural gas and oil 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 in derivative fair value income (loss) in the accompanying consolidated statements of operations (for additional information see table below).

In addition to the collars and call options 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 $2.9 million at September 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 nine months ended September 30, 2010 and 2009 (in thousands):

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Hedge ineffectiveness realized	$	$ 1,581	$ (352)	$ 3,159
unrealized	2,389	(386)	2,400	(483)
Change in fair value of derivatives that do not qualify for hedge accounting[a]	(18,284)	(53,323)	23,885	(83,393)
Realized gain on settlements gas[a] [b]	10,179	51,619	17,230	138,361
Realized gain on settlements oil[a] [b]		27		7,565
Realized gain on early settlement of oil derivatives[c]	15,697		15,697	
Derivative fair value income (loss)	$ 9,981	$ (482)	$ 58,860	$ 65,209

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

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

(c) Not included in realized prices.

The combined fair value of derivatives included in the accompanying consolidated balance sheets as of September 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. In our accompanying consolidated balance sheets, derivative assets and liabilities are netted where derivatives with both gain and loss positions are held by a single counterparty.

	September 30, 2010	December 31, 2009
Derivative assets:		
Natural gas collars	$ 248,474	$ 26,649
basis swaps	(977)	(1,063)
Crude oil collars	(8,198)	66
call options	(39,302)	
	$ 199,997	$ 25,652
Derivative liabilities:		
Natural gas collars	$	$ 2,020
basis swaps	(1,957)	(16,779)
	$ (1,957)	$ (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 accompanying consolidated balance sheets (in thousands):

	September 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]	$ 228,299	$	$ 228,299	$ 22,062	$	$ 22,062
	$ 228,299	$	$ 228,299	$ 22,062	$	$ 22,062
Derivatives that do not qualify for hedge accounting:						
Collars[1]	$ 20,228	$ (8,251)	$ 11,977	$ 6,673	$	$ 6,673
Basis swaps[1]		(2,934)	(2,934)	65	(17,907)	(17,842)
Call options[1]		(39,302)	(39,302)			
	$ 20,228	$ (50,487)	$ (30,259)	$ 6,738	$ (17,907)	$ (11,169)

(1) Included in unrealized derivative gain or loss in the accompanying consolidated balance sheets.

The effects of our cash flow hedges (or those derivatives that qualify for hedge accounting) on accumulated other comprehensive income (loss) included in our consolidated balance sheets is summarized below (in thousands):

	Three Months Ended September 30,				Nine Months Ended September 30,			
	Change in Hedge Derivative Fair Value		Realized Gain Reclassified from AOCI into Revenue [a]		Change in Hedge Derivative Fair Value		Realized Gain Reclassified from AOCI into Revenue [a]	
	2010	2009	2010	2009	2010	2009	2010	2009
Collars	$ 109,651	$ (1,934)	$ 15,616	$ 54,362	$ 187,594	$ 67,386	$ 35,171	$ 158,842
Income taxes	(42,683)	716	(6,014)	(20,114)	(72,301)	(25,421)	(13,445)	(58,772)
	$ 66,968	$ (1,218)	$ 9,602	$ 34,248	$ 115,293	$ 41,965	$ 21,726	$ 100,070

(a) For realized gains upon contract settlement, the reduction in AOCI is offset by an increase in natural gas, NGL and oil sales. For realized losses upon contract settlement, the increase in AOCI is offset by a decrease in natural gas, NGL and oil sales.

The effects of our non-hedge derivatives (or those derivatives that do not qualify for hedge accounting) and the ineffective portion of our hedge derivatives included in our consolidated statements of operations is summarized below (in thousands):

	Three Months Ended September 30,					
	Gain (Loss) Recognized in Income (Non-hedge Derivatives)		Gain Recognized in Income (Ineffective Portion)		Derivative Fair Value Income (Loss)	
	2010	2009	2010	2009	2010	2009
Swaps	$	$ 6,540	$	$	$	$ 6,540
Collars	12,559	4,976	2,389	1,195	14,948	6,171
Call options	(3,823)				(3,823)	
Basis swaps	(1,144)	(13,193)			(1,144)	(13,193)
Total	$ 7,592	$ (1,677)	$ 2,389	$ 1,195	$ 9,981	$ (482)

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	Nine Months Ended September 30,					
	Gain (Loss) Recognized in Income (Non-hedge Derivatives)		Gain Recognized in Income (Ineffective Portion)		Derivative Fair Value Income (Loss)	
	2010	2009	2010	2009	2010	2009
Swaps	$	$ 60,098	$	$	$	$ 60,098
Collars	60,998	29,846	2,048	2,676	63,046	32,522
Call options	(3,823)				(3,823)	
Basis swaps	(363)	(27,411)			(363)	(27,411)
Total	$ 56,812	$ 62,533	$ 2,048	$ 2,676	$ 58,860	$ 65,209

(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 September 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 September 30, 2010
Trading securities held in our deferred compensation plans	$ 47,509	$	$	$ 47,509
Derivatives collars		240,276		240,276
call options		(39,302)		(39,302)
basis swaps		(2,934)		(2,934)

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 September 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 in other assets in our accompanying consolidated balance sheets. 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 in deferred compensation plan expense in our consolidated statements of operations. For the three months ended September 30, 2010, interest and dividends were $44,000 and mark-to-market was a gain of $3.5 million. For the three months ended September 30, 2009, interest and dividends were $45,000 and mark-to-market was a gain of $5.7 million. For the nine months ended September 30, 2010, interest and dividends were $118,000 and mark-to-market was a gain of $8.2 million. For the nine months ended September 30, 2009, interest and dividends were $138,000 and mark-to-market was a gain of $9.1 million. For additional information on the accounting for our deferred compensation plan, see Note 13.

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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 (in thousands).

	Three Months Ended September 30,				Nine Months Ended September 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	$	$
Equity investments	$	$	$	$	$	$	$10,665	$2,950

In first quarter 2010, we recorded natural gas and oil 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. 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. In the prior year, the fair value of our equity investments was measured using an income approach based upon internal estimates of business activity levels, prices and discount rate, which are level 3 inputs. Based on the analyses, we determined our equity investment was not recoverable and recorded an impairment.

Fair Values-Reported

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

	September 30, 2010		December 31, 2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Assets:				
Commodity collars, call options and basis swaps	$ 199,997	$ 199,997	$ 25,652	$ 25,652
Marketable securities[(a)]	47,509	47,509	43,554	43,554
Liabilities:				
Commodity collars, call options and basis swaps	(1,957)	(1,957)	(14,759)	(14,759)
Long-term debt[(b)]	(1,851,260)	(2,269,390)	(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 deemed necessary to limit risk of loss. Our allowance for uncollectible receivables was $1.4 million at September 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 September 30, 2010, these contracts consist of collars, call options 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 September 30, 2010, our net derivative payable includes a payable to J. Aron & Company of $316,000. None of our derivative contracts have margin requirements or collateral provisions that would require funding prior to the scheduled cash settlement date.

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(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	1,389,636	46.10
Exercised	(1,623,939)	19.20
Expired/forfeited	(94,212)	46.73
Outstanding on September 30, 2010	6,826,197	$ 37.06

The weighted average fair value of a SAR to purchase one share of common stock granted during 2010 was $17.02. The fair value of each 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 6.8 million stock option/SARs outstanding at September 30, 2010, 785,000 are stock options and 6.0 million are SARs.

Restricted Stock Grants

During the first nine months of 2010, 392,000 shares of restricted stock (or non-vested shares) were issued to employees at an average price of $45.85 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 nine months of 2009, we issued 539,000 shares of restricted stock as compensation to employees at an average price of $37.83 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 $16.0 million in the first nine months of 2010 compared to $13.1 million in the nine month period ended September 30, 2009. As of September 30, 2010, unrecognized compensation cost related to restricted stock awards was $27.8 million, which is expected to be recognized over the weighted average period of two years. Substantially all of our restricted stock grants are held in our deferred compensation plans. All restricted stock awards held in our deferred compensation plans are classified as a liability award and remeasured at fair value each reporting period. This mark-to-market is included in deferred compensation plan expense in our accompanying consolidated statements 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 September 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	412,859	45.83
Vested	(335,088)	46.84
Forfeited	(18,499)	46.04

Non-vested shares outstanding at September 30, 2010	686,461	$	45.16

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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. 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 statements of operations. The assets of the Rabbi Trust, other than Range common stock, are invested in marketable securities and reported at market value in other assets in the accompanying consolidated balance sheets. Changes in the market value of the marketable securities are charged or credited to deferred compensation plan expense each quarter. The deferred compensation liability included in our consolidated balance sheets 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 related to our deferred compensation plan of $5.3 million in the three months ended September 30, 2010 compared to expense of $16.4 million in the same period of 2009. We recorded non-cash, mark-to-market income related to our deferred compensation plan of $25.2 million in the first nine months of 2010 compared to mark-to-market expense of $29.6 million in the first nine months of 2009.

(14) SUPPLEMENTAL CASH FLOW INFORMATION

	Nine Months Ended September 30,	
	2010	2009
	(in thousands)	
Non-cash investing and financing activities included:		
Asset retirement costs capitalized (removed), net	$ 1,229	$ (3,373)
Unproved property purchased with stock[a]	$20,000	$20,548
Net cash provided from operating activities included:		
Interest paid	$74,732	$66,556
Income taxes refunded	$ (807)	$ (493)

[a] Nine months ended September 30, 2010 included shares that 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)]

	September 30, 2010	December 31, 2009
	(in thousands)	
Natural gas and oil properties:		
Properties subject to depletion	$ 5,921,282	$ 5,534,204
Unproved properties	826,979	774,503
Total	6,748,261	6,308,707
Accumulated depreciation, depletion and amortization	(1,553,257)	(1,409,888)
Net capitalized costs	$ 5,195,004	$ 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]

	Nine Months Ended September 30, 2010	Year Ended December 31, 2009
	(in thousands)	
Acquisitions:		
Unproved leasehold	$ 2,646	$
Proved properties	132,338	
Asset retirement obligations	556	
Acreage purchases[b]	114,734	176,867
Development	552,895	497,702
Exploration:		
Drilling	28,932	57,121
Expense	41,113	42,082
Stock-based compensation expense	3,231	4,817
Gas gathering facilities	17,055	29,524
Subtotal	893,500	808,113
Asset retirement obligations	1,229	6,131
Total costs incurred	$ 894,729	$ 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 in our accompanying consolidated statement of operations. As part of their severance agreement, our Ohio employees vesting of SARs and restricted stock grants was accelerated, increasing 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 which is reflected in termination costs in our accompanying consolidated statements of operations of which $840,000 was recorded in third quarter 2009. 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 the accompanying consolidated balance sheets as of September 30, 2010 (in thousands):

Balance at December 31, 2009	$ 1,568
Accrued one-time termination costs	5,138
Payments	(5,388)
Balance at September 30, 2010	$ 1,318

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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 as filed with our Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 filed with the SEC on July 27, 2010.

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 natural gas, NGL and oil revenue, natural gas and oil properties, stock-based compensation, derivative financial instruments, asset retirement obligations and deferred income taxes.

Market Conditions

Prices for various quantities of natural gas, natural gas liquids (NGLs) and oil 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 natural gas and oil for the three and nine months ended September 30, 2010 and 2009. There is no similar published benchmark for NGL prices.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Average NYMEX prices[a]				
Natural gas (per mcf)	$ 4.42	$ 3.41	$ 4.61	$ 3.93
Oil (per bbl)	$76.18	$68.18	$77.62	$56.01

[a] Based on average of bid week prompt month prices.

Consolidated Results of Operations

Overview

We are a Fort Worth, Texas-based independent natural gas company, engaged in the exploration, development and acquisition of primarily natural gas properties, mostly in the Southwestern and Appalachian regions of the United States. Our objective is to build stockholder value through consistent growth in reserves and production on a cost-efficient basis.

During the first nine months of 2010, we completed several important initiatives and achieved several milestones as follows:

- recorded our 31st consecutive quarter of sequential production growth;
- achieved 12% year-over-year production growth;

daily production now exceeds 500,000 mcfe per day;

direct operating expense per mcfe declined 16% when compared to the prior year;

sold our tight gas sand properties in Ohio for proceeds of $323.0 million;

issued $500.0 million senior subordinated notes for proceeds of $491.3 million;

used a portion of the proceeds received from the issuance of our 6.75% senior subordinated notes due 2020 to redeem all $200.0 million aggregate principal amount of our 7.375% senior subordinated notes due 2013; and

entered into additional commodity derivative contracts for 2010, 2011 and 2012.

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Third Quarter Highlights

Total revenues increased $23.3 million, or 11% for third quarter 2010 over the same period of 2009. The increase includes a $17.4 million increase in natural gas, NGL and oil sales and an increase in derivative fair value income (loss) of $10.4 million. Natural gas, NGL and oil sales vary due to changes in volumes of production sold and realized commodity prices. Due to lower derivative settlements and volatility in commodity prices, realized prices decreased from the same period of the prior year, which was more than offset by an increase in production, including a 136% increase in natural gas liquid production primarily due to increased liquids-rich production in our Appalachia area. For third quarter 2010, production increased 15% from the same period of the prior year while realized prices (including all derivative settlements) declined 22%. We believe natural gas, NGL and oil 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, 2011 and 2012, a sustained lower price environment would result in lower realized prices for unprotected volumes and reduce the prices we can enter into derivative contracts for additional volumes in the future.

We continue to focus our efforts on improving our operating efficiency. These efforts resulted in 4% lower direct operating expense per mcfe for third 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, along with increasing public relations costs in the Marcellus Shale associated with our efforts to educate the public about the benefits of natural gas.

Natural Gas, NGL and Oil Sales Production and Realized Price Calculation

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

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2010	2009	Change	%	2010	2009	Change	%
Gas wellhead	$ 129,557	$ 97,004	$ 32,553	34%	$ 416,250	$ 300,646	$ 115,604	38%
Gas hedges realized	15,616	54,122	(38,506)	(71%)	35,148	146,594	(111,446)	(76%)
Total gas sales	145,173	151,126	(5,953)	(4%)	451,398	447,240	4,158	1%
NGL	43,562	16,887	26,675	158%	112,061	36,455	75,606	207%
Oil wellhead	30,825	33,869	(3,044)	(9%)	99,622	101,892	(2,270)	(2%)
Oil hedges realized		240	(240)	(100%)	23	12,247	(12,224)	(100%)
Total oil sales	30,825	34,109	(3,284)	(10%)	99,645	114,139	(14,494)	13%
	203,944	147,760	56,184	38%	627,933	438,993	188,940	43%

Combined wellhead								
Combined hedges realized	15,616	54,362	(38,746)	(71%)	35,171	158,841	(123,670)	(78%)
Total natural gas, NGL and oil sales	$ 219,560	$ 202,122	$ 17,438	9%	$ 663,104	$ 597,834	$ 65,270	11%

Our production continues to grow through continued drilling success as we place new wells into production, partially offset by the natural decline of our wells and asset sales. For third quarter 2010, total production volumes, when compared to the same period of the prior year, increased 44% in our Appalachian area and decreased 6% in our Southwestern area. For the nine months ended September 30, 2010, our production volumes as compared to the same period of the prior year, increased 44% in our Appalachia area and decreased 9% in our Southwestern area. For third quarter 2010, NGL production increased 136% from the same period of the prior year primarily due to increased liquids-rich gas production in our Appalachia area along with an increase in processing capacity in the region. In addition, in third quarter 2010 we began reporting certain NGL production that had historically been combined with our natural gas production. This change affects our Southwestern area volumes only, where we previously only reported NGL volumes from significant fields and increased our third quarter production volumes approximately 2%. Crude oil production declined primarily due to the sale of oil properties in West Texas effective September 30, 2009. Our production for the three months and the nine months ended September 30, 2010 and 2009 is shown below:

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	Three Months Ended September 30,				Nine Months Ended September 30,			
	2010	2009	Change	%	2010	2009	Change	%
Production[a]:								
Natural gas (mcf)	35,818,171	33,747,972	2,070,199	6%	104,320,417	96,205,898	8,114,519	8%
NGLs (bbls)	1,279,751	543,005	736,746	136%	2,989,106	1,492,259	1,496,847	100%
Crude oil (bbls)	461,145	534,399	(73,254)	(14%)	1,460,565	1,987,603	(527,038)	(27%)
Total (mcfe)[b]	46,263,547	40,212,396	6,051,151	15%	131,018,443	117,085,070	13,933,373	12%
Average daily production[a]:								
Natural gas (mcf)	389,328	366,826	22,502	6%	382,126	352,403	29,723	8%
NGLs (bbls)	13,911	5,902	8,009	136%	10,949	5,466	5,483	100%
Crude oil (bbls)	5,012	5,809	(797)	(14%)	5,350	7,281	(1,931)	(27%)
Total (mcfe)[b]	502,865	437,091	65,774	15%	479,921	428,883	51,038	12%

(a) Represents volumes sold regardless of when produced.

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

Our average realized price (including all derivative settlements) received was $4.97 per mcfe in third quarter 2010 compared to $6.35 per mcfe in the same period of the prior year. Our average realized price calculation (including all derivative settlements) includes all cash settlements for derivatives, whether or not they qualify for hedge accounting, except that in the third quarter and the nine months ended September 30, 2010, we have excluded from average realized price calculations a $15.7 million gain related to an early settlement of oil collars. Our realized prices for the three months and the nine months ended September 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 periods. This reduced our average realized price by $0.12 per mcfe in the third quarter 2010 and $0.20 per mcfe in the nine months ended September 30, 2010 compared to a decrease of $0.02 per mcfe in the third quarter 2009 and an increase of $0.02 per mcfe in the nine months ended September 30, 2009. Average price calculations for the three months and the nine months ended September 30, 2010 and 2009 are shown below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Average sales prices (wellhead):				
Natural gas (per mcf)	$ 3.62	$ 2.87	$ 3.99	$ 3.13
NGLs (per bbl)	34.04	31.10	37.49	24.43
Crude oil (per bbl)	66.84	63.38	68.21	51.26
Total (per mcfe)[a]	4.41	3.67	4.79	3.75
Average realized price (including derivatives that qualify for hedge accounting):				

Natural gas (per mcf)	4.05	4.48	4.33	4.65
NGLs (per bbl)	34.04	31.10	37.49	24.43
Crude oil (per bbl)	66.84	63.83	68.22	57.43
Total (per mcfe)[a]	4.75	5.03	5.06	5.11
Average realized price (including all derivative settlements[b]):				
Natural gas (per mcf)	4.34	6.05	4.49	6.12
NGLs (per bbl)	34.04	31.10	37.49	24.43
Crude oil (per bbl)	66.84	63.88	68.23	61.24
Total (per mcfe)[a]	4.97	6.35	5.19	6.38

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

(b) Excludes oil collar derivatives that were settled early for a gain of $15.7 million.

Derivative fair value income (loss) was a gain of $10.0 million in third quarter 2010 compared to a loss of $482,000 in the same period of 2009. Derivative fair value income (loss) was a gain of $58.9 million in the nine months ended September 30, 2010 compared to a gain of $65.2 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) in our accompanying consolidated statements of operation. 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 sheets. 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 (loss) for the three months and the nine months September 30, 2010 and 2009 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Hedge ineffectiveness realized[c]	$	$ 1,581	$ (352)	$ 3,159
unrealized[a]	2,389	(386)	2,400	(483)
Change in fair value of derivatives that do not qualify for hedge accounting[a]	(18,284)	(53,323)	23,885	(83,393)
Realized gain on settlements gas[b][c]	10,179	51,619	17,230	138,361
Realized gain on settlements oil[b][c]		27		7,565
Realized gain on early settlement of oil derivatives [d]	15,697		15,697	
Derivative fair value income (loss)	$ 9,981	$ (482)	$ 58,860	$ 65,209

(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).

(d) This early settlement is not included in average realized price calculations.

Gain on the sale of assets for third quarter 2010 increased $35,000 from the same period of the prior year. For the nine months ended September 30, 2010, we recorded a total 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 third quarter 2010 was a loss of $1.0 million compared to a loss of $475,000 in the same period of 2009. Third quarter 2010 includes a loss from equity method investments of $845,000. The third quarter of 2009 includes a loss from equity method investments of $1.0 million. Other income (loss) for the nine months ended September 30, 2010 improved from a loss of $6.7 million in 2009 to a loss of $2.0 million in 2010. Loss from equity method investments for the nine months ended September 30, 2010 was a loss of $1.8 million compared to a loss of $6.5 million in the same period of 2009. The nine months ended September 30, 2009 also includes an impairment of one of our equity method investments of $3.0 million.

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 nine months ended September 30, 2010 and 2009:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2010	2009	Change	%	2010	2009	Change	%
Direct operating expense	$0.74	$0.77	$(0.03)	(4%)	$0.73	$0.87	$(0.14)	(16%)
Production and ad valorem tax expense	0.19	0.19		%	0.19	0.20	(0.01)	(5%)
General and administrative expense	0.79	0.74	0.05	7%	0.77	0.72	0.05	7%
Interest expense	0.73	0.76	(0.03)	(4%)	0.72	0.74	(0.02)	(3%)
Depletion, depreciation and amortization expense	1.98	2.42	(0.44)	(18%)	2.07	2.31	(0.24)	(10%)

Direct operating expense increased $3.2 million in third quarter 2010 to $34.3 million. We experience increases in operating expenses as we add new wells and maintain production from existing properties. We incurred $1.1 million ($0.02 per mcfe) of workover costs in third quarter 2010 versus $2.7 million ($0.07 per mcfe) in 2009. On a per mcfe basis, direct operating expenses for third quarter 2010 decreased $0.03, or 4%, from the same period of 2009 with the decrease primarily due to lower workover costs. 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 relative to our other operating areas. Direct operating expense was $95.1 million for the first nine months of 2010 compared to $101.5 million in the same period of the prior year. We incurred $3.8 million ($0.03 per mcfe) of workover costs in the first nine months of 2010 compared to $5.3 million ($0.05 per mcfe) in 2009. On a per mcfe basis, direct operating expenses for the nine months 2010 decreased $0.14, or 16% from the same period of the prior year with the decrease consisting primarily of lower workover costs ($0.02 per mcfe), lower water disposal costs ($0.02 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 nine months ended September 30, 2010 and 2009:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2010	2009	Change	%	2010	2009	Change	%
Lease operating expense	$ 0.71	$ 0.68	$ 0.03	4%	$ 0.69	$ 0.80	$ (0.11)	(14%)
Workovers	0.02	0.07	(0.05)	(71%)	0.03	0.05	(0.02)	(40%)
Stock-based compensation (non-cash)	0.01	0.02	(0.01)	(50%)	0.01	0.02	(0.01)	(50%)
Total direct operating expenses	$ 0.74	$ 0.77	$ (0.03)	(4%)	$ 0.73	$ 0.87	$ (0.14)	(16%)

Third quarter 2009 included $3.8 million of operating costs related to properties sold during 2009 and in 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 $0.73. The first nine months of 2009 included $15.8 million of operating costs related to properties sold during 2009 and in 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 $0.79.

Production and ad valorem taxes are paid based on market prices and not hedged prices. For the third quarter, these taxes increased $1.3 million or 17% from the same period of the prior year due to higher market prices and higher property taxes which were somewhat offset by an increase in production volumes not subject to production taxes. On a per mcfe basis, production and ad valorem taxes were $0.19 in both the third quarter 2010 and the third quarter 2009. For the first nine months of 2010, these taxes increased 7% from the same period of the prior year due to higher market prices which was 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 nine months of 2010 compared to $0.20 in the same period of 2009.

General and administrative expense for third quarter 2010 increased $6.6 million or 22% from the same period of the prior year due primarily to higher community relations costs ($3.8 million), higher salaries and benefits ($1.6 million), and higher office expenses, including information technology. General and administrative expense for the first nine months of 2010 increased $16.6 million or 20% from the same period of the prior year due to higher stock-based compensation ($3.7 million), an increase in legal fees and lawsuit settlements ($3.2 million), higher salaries and benefits ($2.3 million), higher community relations costs ($3.9 million) and higher office expenses, including information technology and industry trade 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 nine months ended September 30, 2010 and 2009:

	Three Months Ended	Nine Months Ended

	September 30,				September 30,			
	2010	2009	Change	%	2010	2009	Change	%
General and administrative	$ 0.62	$ 0.55	$ 0.07	13%	$ 0.57	$ 0.53	$ 0.04	8%
Stock-based compensation (non-cash)	0.17	0.19	(0.02)	(11%)	0.20	0.19	0.01	5%
Total general and administrative expenses	$ 0.79	$ 0.74	$ 0.05	7%	$ 0.77	$ 0.72	$ 0.05	7%

Interest expense for third quarter 2010 increased $3.2 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 August 2010, we issued $500.0 million of 6.75% senior subordinated notes due 2020, which added $4.6 million of interest costs in third quarter 2010. The proceeds from the issuance were used to retire our 7.375% senior subordinated notes due 2013 and to lower our floating interest rate bank debt due 2012, 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 third quarter 2010 was $361.2 million compared to $430.7 million for the same period of the prior year and the weighted average interest rate was 2.3% in third quarter 2010 compared to 2.2% in the same period of the prior year. Interest expense for the nine months ended September 30, 2010 increased $8.1 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 nine months ended September 30, 2010, was $380.6 million compared to $644.5 million for the same period of the prior year and the weighted average interest rate was 2.2% in the first nine months of 2010 compared to 2.5% in the same period of the prior year.

Depletion, depreciation and amortization (DD&A) decreased $5.4 million, or 6%, to $91.8 million in third quarter 2010. The decrease was due to a 17% decrease in depletion rates partially offset by a 15% increase in production. On a per mcfe basis, DD&A decreased from $2.42 in third quarter 2009 to $1.98 in third quarter 2010. In the first nine months of 2010, DD&A increased $1.1 million due to a 12% increase in production which was significantly offset by a 9% decrease in depletion rates. Depletion rates are declining due to our lower finding and development costs and the mix of our production. The following table summarizes DD&A expense per mcfe for the three months and the nine months ended September 30, 2010 and 2009:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2010	2009	Change	%	2010	2009	Change	%
Depletion and amortization	$ 1.87	$ 2.26	$ (0.39)	(17%)	$ 1.95	$ 2.15	$ (0.20)	(9%)
Depreciation	0.08	0.12	(0.04)	(33%)	0.09	0.12	(0.03)	(25%)
Accretion and other	0.03	0.04	(0.01)	(25%)	0.03	0.04	(0.01)	(25%)
Total DD&A expense	$ 1.98	$ 2.42	$ (0.44)	(18%)	$ 2.07	$ 2.31	$ (0.24)	(10%)

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, loss on early extinguishment of debt and impairment of proved properties. In the three months and the nine months ended September 30, 2010 and 2009, stock-based compensation represents the amortization of restricted stock grants and expenses related to SAR grants. In third quarter 2010, stock-based compensation is a component of direct operating expense ($606,000), exploration expense ($1.0 million) and general and administrative expense ($7.8 million) for a total of $9.7 million. In third quarter 2009, stock-based compensation was a component of direct operating expense ($798,000), exploration expense ($979,000) and general and administrative expense ($7.5 million) for a total of $9.5 million. In the nine months ended September 30, 2010, stock based compensation is a component of direct operating expense ($1.7 million), exploration expense ($3.2 million), general and administrative expense ($26.4 million) and termination costs ($2.8 million) for a total of $35.1 million. In the nine months ended September 30, 2009, stock based compensation is a component of direct operating expense ($2.4 million), exploration expense ($2.9 million), general and administrative expense ($22.7 million) for a total of $28.7 million.

Exploration expense increased $4.3 million in third quarter 2010 with higher dry hole costs and higher delay rentals. Exploration expense increased $8.7 million in the first nine months of 2010 primarily due to higher delay rental costs and higher dry hole costs partially offset by lower seismic costs. The higher delay rental payments, or costs to defer the commencement of drilling, is primarily attributable to our Marcellus Shale operations. The following table details our exploration-related expenses for the three months and the nine months ended September 30, 2010 and 2009 (in thousands):

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2010	2009	Change	%	2010	2009	Change	%
Dry hole expense	$ 1,662	$ 212	$ 1,450	684%	$ 1,662	$ 343	$ 1,319	385%
Seismic	6,433	6,267	166	3%	14,992	20,182	(5,190)	(26%)
Personnel expense	2,892	2,527	365	14%	8,658	8,232	426	5%
Stock-based compensation expense	1,018	979	39	4%	3,097	2,933	164	5%
Delay rentals and other	3,231	917	2,314	252%	15,935	3,919	12,016	307%
Total exploration expense	$ 15,236	$ 10,902	$ 4,334	40%	$ 44,344	$ 35,609	$ 8,735	25%

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Abandonment and impairment of unproved properties expense was $20.5 million during the three months ended September 30, 2010 compared to $24.1 million during the same period of 2009. Abandonment and impairment of unproved properties was $46.4 million in the nine months ended September 30, 2010 compared to $84.6 million during the same period for 2009. Abandonment and impairment of unproved properties in 2009 was primarily related to higher Barnett Shale lease expirations. We assess individually significant unproved properties for impairment on a quarterly basis and recognize a loss where circumstances indicate an impairment of value. 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 nine 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. Termination costs in the three months and the nine months ended September 30, 2009 represent severance costs related to the closing of our Houston office.

Deferred compensation plan expense was income of $5.3 million in third quarter 2010 compared to expense of $16.4 million 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 deferred compensation liability is adjusted to fair value by a charge or a credit to deferred compensation plan expense in the accompanying statement of operations. Our stock price decreased from $40.15 at June 30, 2010 to $38.13 at September 30, 2010. During the same period in the prior year, our stock price increased from $41.41 at June 30, 2009 to $49.36 at September 30, 2009. Deferred compensation plan expense was income of $25.2 million in the nine months ended September 30, 2010 compared to expense of $29.6 million in the same period of the prior year. Our stock price decreased from $49.85 at December 31, 2009 to $38.13 at September 30, 2010. During the same nine month period of 2009, our stock price increased from $34.39 at December 31, 2008 to $49.36 at September 30, 2009.

Loss on early extinguishment of debt for the third quarter and the nine months ended September 30, 2010 was $5.4 million. In August 2010 we redeemed our 7.375% senior subordinated notes due 2013 at a redemption price equal to 101.229%. We recorded a loss on extinguishment of debt of $5.4 million which includes call premium costs of $2.5 million and expensing of related deferred financing costs on the repurchased debt.

Impairment of proved properties in the first nine months of 2010 of $6.5 million was recognized due to declining gas prices and is related to a portion of 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 were 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 at the time of the impairment.

Income tax (benefit) expense for third quarter 2010 decreased to a benefit of $5.9 million from a benefit of $15.3 million in third quarter 2009, reflecting a 69% improvement in net loss from operations before taxes compared to the same period of 2009. Third quarter 2010 provided for tax benefit at an effective rate of 41.9% compared to tax benefit at an effective rate of 33.9% in the same period of 2009. Income tax expense for the nine months ended September 30, 2010 increased to an expense of $49.5 million from a benefit of $19.0 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 nine months ended September 30, 2010 provided for tax expense at an effective tax rate of 38.7% compared to a tax benefit at an effective tax rate of 33.8% in the same period of the prior year. Third quarter 2010 includes $617,000 additional benefit related to the release of a valuation allowance for capital losses compared to additional expense of $387,000 related to valuation allowances in the same period of 2009. The nine months ended September 30, 2009 included additional expense of $1.1 million for valuation allowances. The increase in effective tax rates is also 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.

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 a portion of these proceeds to purchase proved and unproved properties primarily in Virginia. The remainder of these proceeds was used to repay amounts under our bank credit facility. In the first nine months of 2010, we also entered into additional commodity derivative contracts for 2010, 2011 and 2012 to protect future cash flows. As part of our semi-annual bank review completed October 8, 2010, our borrowing base and facility amounts were reaffirmed at $1.5 billion and $1.25 billion.

During the nine months ended September 30, 2010, our cash provided from operating activities was $398.9 million and we spent $602.0 million on capital expenditures and $249.7 million on proved and unproved property purchases. At September 30, 2010, we had $2.1 million in cash, total assets of $5.8 billion and a debt-to-capitalization ratio of 41.8%. Long-term debt at September 30, 2010 totaled $1.9 billion, which included $165.0 million of bank credit facility debt and $1.7 billion of senior subordinated notes. Available committed borrowing capacity under the bank credit facility at September 30, 2010 was $1.1 billion.

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 economic, long-term 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 prices or a reduction in production and reserves would reduce our ability to fund capital expenditures, reduce debt, meet financial obligations and remain profitable. 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 natural gas, NGLs and oil, 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 September 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 $1.0 billion on October 25, 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 September 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 natural gas, NGL and oil production at the wellhead under floating market contracts. However, we generally hedge a substantial, but varying, portion of our anticipated future natural gas and oil 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 September 30, 2010, we have entered into derivative agreements covering 31.4 Bcfe for 2010, 161.0 Bcfe for 2011 and 40.6 Bcfe for 2012.

Net cash provided from operating activities for the nine months ended September 30, 2010 was $398.9 million compared to $443.8 million in the nine months ended September 30, 2009. Cash flow from operating activities for the first nine 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 and higher operating costs. 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 our consolidated statements of cash flows) in the nine months ended September 30, 2010 was an increase of $29.3 million compared to a decrease of $11.1 million in the same period of the prior year.

Net cash used in investing activities for the nine months ended September 30, 2010 was $528.8 million compared to $385.1 million in the same period of 2009. During the nine months ended September 30, 2010, we:

- spent $589.8 million on oil and gas property additions;
- spent $114.7 million on acreage primarily in the Marcellus Shale;
- spent $135.0 million on the purchase of proved and unproved property in Virginia; and
- received proceeds of $327.5 million primarily from the sale of Ohio oil and gas properties.

During the nine months ended September 30, 2009, we:

- spent $425.4 million on oil and gas property additions;
- spent $118.7 million on acreage primarily in the Marcellus Shale; and
- received proceeds of $182.2 million primarily from the sale of West Texas oil and gas properties.

Net cash provided from financing activities for the nine months ended September 30, 2010 was $128.3 million compared to net cash used in financing activities of $58.6 million in the same period of 2009. During the nine months ended September 30, 2010, we:

- borrowed $784.0 million and repaid $943.0 million under our bank credit facility, ending the period with $159.0 million lower bank credit facility balance;
- issued $500.0 million aggregate principal amount of our 6.75% senior subordinated notes due 2020 at par; and
- redeemed $200.0 million aggregate principal amount of our 7.375% senior subordinated notes due 2013 at a redemption price of 101.229%.

During the nine months ended September 30, 2009, we:

- borrowed $582.0 million and repaid $877.0 million under our bank credit facility, ending the period with $295.0 million lower bank credit facility balance; and
- issued $300.0 million aggregate principal amount of our 8% senior subordinated notes due 2019, at a discount.

Dividends

On September 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 September 30, 2010 to stockholders of record at the close of business on

September 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 nine months include $98.2 million of purchases in the Marcellus Shale and $8.8 million in the Barnett Shale, which were funded with borrowings under our credit facility. For the nine months ended September 30, 2010, $626.2 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 choose to 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.

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Our contractual obligations include long-term debt, operating leases, drilling commitments, derivative obligations, transportations commitments and other purchase obligations. The table below summarizes our significant contractual obligations as of September 30, 2010 (in thousands).

	Payment due by period					
	Remaining 2010	2011	2012	2013 and 2014	Thereafter	Total
Bank debt due 2012	$	$	$ 165,000(a)	$	$	$ 165,000
6.375% senior subordinated notes due 2015					150,000	150,000
7.5% senior subordinated notes due 2016					250,000	250,000
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					300,000	300,000
6.75% senior subordinated notes due 2020					500,000	500,000
Operating leases	2,872	10,316	9,275	13,261	34,201	69,925
Drilling rig commitments	18,216	72,270	53,034	14,905		158,425
Transportation commitments	14,685	61,254	58,390	111,197	381,341	626,867
Other purchase obligations	8,748	50,995	42,980	2,727		105,450
Derivative obligations (b)	1,660	297				1,957
Asset retirement obligation liability (c)	71	2,374	5,691	3,006	59,061	70,203
Total contractual obligations (d)	$ 46,252	$ 197,506	$ 334,370	$ 145,096	$ 2,174,603	$ 2,897,827

(a) Due at termination date of our bank credit facility. We expect to renew our bank credit facility, but there is no assurance that can be accomplished. Interest paid on our bank credit facility would be approximately $3.8 million each year assuming no change in the interest rate or outstanding balance.

(b) Derivative obligations represent net open derivative contracts valued as of September 30, 2010. While such payments will be funded by higher prices received from the sale of our production, production receipts may be received after our payments to counterparties, which can result in borrowings under our bank credit facility.

(c) The ultimate settlement and timing cannot be precisely determined in advance.

(d) This table excludes the liability for the deferred compensation plans since these obligations will be funded with existing plan assets.

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   Natural Gas and Oil 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. Historically, these contracts consisted of collars and fixed price swaps. In September 2010, we also entered into call options where we sold call options on a portion of our anticipated oil production in exchange for a premium received from the counterparty. 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 September 30, 2010, we had collars covering 209.5 Bcf of gas at weighted average floor and cap prices of $5.55 and $6.56 per mcf and 0.8 million barrels of oil at weighted average floor and cap prices of $70.56 and $81.54 per barrel. At September 30, we also had sold call options covering 3.1 million barrels of oil at a weighted average price of $81.77. 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 September 30, 2010 was a net unrealized pre-tax gain of $201.0 million. The contracts expire monthly through December 2012. Settled transaction gains and losses for derivatives that qualify for hedge accounting are determined monthly and are included as increases or decreases in natural gas, NGLs and oil sales in the period the hedged production is sold. In the first nine months of 2010, natural gas, NGLs and oil sales included realized hedging gains of $35.2 million compared to gains of $158.8 million in the same period of 2009.

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

Period	Contract Type	Volume Hedged	Average Hedge Price
Natural Gas			
2010	Collars	335,000 Mmbtu/day	$5.56-$7.20
2011	Collars	408,200 Mmbtu/day	$5.56-$6.48
2012	Collars	80,993 Mmbtu/day	$5.50-$6.25
Crude Oil			
2010	Collars	1,000 bbls/day	$75.00-$93.75
2012	Collars	2,000 bbls/day	$70.00-$80.00
2011	Call options	5,500 bbls/day	$80.00
2012	Call options	3,000 bbls/day	$85.00

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 natural gas and oil 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 in the accompanying consolidated balance sheets. We recognize all unrealized and realized gains and losses related to these contracts as derivative fair value income or loss in our consolidated statements of operations. As of September 30, 2010, derivatives on 37.5 Bcfe no longer qualify or are not designated for hedge accounting.

In addition to the collars and call options 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 $2.9 million at September 30, 2010.

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Interest Rates

At September 30, 2010, we had $1.9 billion of debt outstanding. Of this amount, $1.7 billion bore interest at fixed rates averaging 7.2%. Bank debt totaling $165.0 million bears interest at floating rates, which approximated 2.3% at September 30, 2010. The 30-day LIBOR rate on September 30, 2010 was 0.3%.

Inflation and Changes in Prices

Our revenues, the value of our assets and our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes natural gas and oil prices and the costs to produce our reserves. Natural gas and oil prices are subject to fluctuations that are beyond our ability to control or predict. During third quarter 2010, we received an average of $3.62 per mcf of gas and $66.84 per barrel of oil before derivative contracts compared to $2.87 per mcf of gas and $63.38 per barrel of oil 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 and 2011 to continue to be a function of supply and demand.

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.

Market Risk

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

Commodity Price Risk

We periodically enter into derivative arrangements with respect to our natural gas and oil production. These arrangements are intended to reduce the impact of natural gas and oil price fluctuations. Some 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. In September 2010, we also entered into call option derivative contracts under which we sold call options in exchange for a premium from the counterparty. We took advantage of attractive strip prices in 2011 and 2012 and sold oil call options to our counterparties in exchange for 2011 and 2012 natural gas collars with prices above the current market price. Historically, we applied hedge accounting to derivatives utilized to manage price risk associated with our natural gas and oil production. Accordingly, we recorded the change in the fair value of our swap and collar contracts under the balance sheet caption accumulated other comprehensive income and into natural gas, NGLs and oil 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 in derivative fair value income or loss in our consolidated statements of operations. 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 natural gas and oil production. These contracts are accounted for using the mark-to-market accounting method. Under this method, the contracts are carried at their fair value in unrealized derivative gains and in our consolidated balance sheets. We recognize all unrealized and realized gains and losses related to these contracts in derivative fair value income (loss) in our consolidated statements of operations. 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 September 30, 2010, our net derivative payable includes a payable to J. Aron & Company of $316,000. None of our derivative contracts have margin requirements or collateral provisions that would require funding prior to the scheduled cash settlement date.

As of September 30, 2010, we had collars covering 209.5 Bcf of gas and 0.8 million barrels of oil and oil call options for 3.1 million barrels. These contracts expire monthly through December 2012. The fair value, represented by the estimated amount that would be realized upon immediate liquidation as of September 30, 2010, approximated a net unrealized pre-tax gain of $201.0 million.

We expect our NGL production to continue to increase. We currently have not entered into any NGL derivative contracts. In our Marcellus Shale operations, propane is a large product component of our NGL production, we believe NGL prices are somewhat seasonal. Therefore, the percentage of NGL prices to NYMEX WTI (or West Texas Intermediate) will vary based on product components, seasonality and geographic supply and demand.

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

Period	Contract Type	Volume Hedged	Average Hedge Price	Fair Market Value as of September 30, 2010 Asset (Liability) (in thousands)
Natural Gas				
2010	Collars	335,000 Mmbtu/day	$5.56-$7.20	$ 50,238
2011	Collars	408,200 Mmbtu/day	$5.56-$6.48	$ 179,740
2012	Collars	80,993 Mmbtu/day	$5.50-$6.25	$ 18,496
Crude Oil				
2010	Collars	1,000 bbls/day	$75.00-$93.75	$ 53
2012	Collars	2,000 bbls/day	$70.00-$80.00	$ (8,251)
2011	Call options	5,500 bbls/day	$80.00	$ (23,440)
2012	Call options	3,000 bbls/day	$85.00	$ (15,863)

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 and call options 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 $2.9 million at September 30, 2010.

The following table shows the fair value of our collars and call options and the hypothetical change in the fair value that would result from a 10% and a 25% change in commodity prices at September 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	$240,276	$(85,388)	$(208,742)	$88,404	$226,001
Call options	(39,302)	(18,568)	(50,511)	15,842	33,369

Interest rate risk. At September 30, 2010, we had $1.9 billion of debt outstanding. Of this amount, $1.7 billion bore interest at fixed rates averaging 7.2%. Senior bank debt totaling $165.0 million bore interest at floating rates averaging 2.3%. A 1% increase or decrease in short-term interest rates would affect interest expense by approximately $1.7 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 September 30, 2010 at the reasonable assurance level.

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 September 30, 2010 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II OTHER INFORMATION

ITEM 1A. RISK FACTORS

We are subject to various risks and uncertainties in the course of our business. In addition to the factors discussed elsewhere in this report, you should carefully consider the risks and uncertainties described under Item 1A. Risk Factors filed in our Quarterly Report on Form 10-Q for the quarter ended June 30, 2010.

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)
10.1*	Tenth Amendment to the Third Amended and Restated Credit Agreement dated October 26, 2006 among Range (as borrower) and J.P. Morgan Chase Bank, N.A. and institutions named (therein) as lenders, J.P. Morgan Chase as administrative agent
23.1*	Consent of Wright and Company, independent consulting engineers
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
99.1*	Report of Wright and Company, independent consulting engineers
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
	XBRL Taxonomy Extension Presentation Linkbase Document

101.
PRE**

* 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: October 27, 2010

RANGE RESOURCES CORPORATION

By: /s/ ROGER S. MANNY

Roger S. Manny
Executive Vice President and Chief Financial Officer

Date: October 27, 2010

RANGE RESOURCES CORPORATION

By: /s/ DORI A. GINN

Dori A. Ginn
Principal Accounting Officer and Vice President Controller

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101. PRE**	XBRL Taxonomy Extension Presentation Linkbase Document

* filed herewith

** furnished herewith