RANGE RESOURCES CORP
Form 10-Q
July 23, 2009

Table of Contents

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

FORM 10-Q

(Mark one)

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

For the quarterly period ended June 30, 2009

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

157,255,568 Common Shares were outstanding on July 20, 2009.

RANGE RESOURCES CORPORATION
FORM 10-Q
Quarter Ended June 30, 2009

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.

TABLE OF CONTENTS

Table of Contents

PART I FINANCIAL INFORMATION
Item 1. Financial Statements

RANGE RESOURCES CORPORATION
CONSOLIDATED BALANCE SHEETS
(In thousands, except shares)

	June 30, 2009 (Unaudited)	December 31, 2008 (Restated)
Assets		
Current assets:		
Cash and equivalents	$ 2,152	$ 753
Accounts receivable, less allowance for doubtful accounts of $753 and $954	99,065	162,201
Unrealized derivative gain	169,856	221,430
Inventory and other	22,179	19,927
Total current assets	293,252	404,311
Unrealized derivative gain		5,231
Equity method investments	150,979	147,126
Oil and gas properties, successful efforts method	6,161,834	6,028,980
Accumulated depletion and depreciation	(1,337,153)	(1,186,934)
	4,824,681	4,842,046
Transportation and field assets	157,066	142,662
Accumulated depreciation and amortization	(65,114)	(56,434)
	91,952	86,228
Other assets	75,135	66,937
Total assets	$ 5,435,999	$ 5,551,879
Liabilities		
Current liabilities:		
Accounts payable	$ 131,436	$ 250,640
Asset retirement obligations	2,064	2,055
Accrued liabilities	54,234	47,309
Deferred tax liability	23,986	32,984
Accrued interest	23,134	20,516
Unrealized derivative loss	2,412	10
Total current liabilities	237,266	353,514
Bank debt	403,000	693,000
Subordinated notes and other long term debt	1,383,134	1,097,668
Deferred tax liability	773,277	779,218

Unrealized derivative loss	2,534	
Deferred compensation liability	109,730	93,247
Asset retirement obligations and other liabilities	84,232	83,890
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, 157,255,400 issued at June 30, 2009 and 155,609,387 issued at December 31, 2008	1,573	1,556
Common stock held in treasury, 233,900 shares at June 30, 2009 and December 31, 2008	(8,557)	(8,557)
Additional paid-in capital	1,729,190	1,695,268
Retained earnings	665,752	685,568
Accumulated other comprehensive income	54,868	77,507
Total stockholders equity	2,442,826	2,451,342
Total liabilities and stockholders equity	$ 5,435,999	$ 5,551,879

See accompanying notes.

Table of Contents

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
		(Restated)		(Restated)
Revenues				
Oil and gas sales	$ 192,523	$ 347,622	$ 395,712	$ 655,006
Transportation and gathering	2,152	1,224	1,647	2,353
Derivative fair value (loss) income	(9,856)	(196,684)	65,691	(320,451)
Other	(4,387)	(359)	(6,181)	20,233
Total revenues	180,432	151,803	456,869	357,141
Costs and expenses				
Direct operating	34,828	37,228	70,369	70,178
Production and ad valorem taxes	7,564	16,056	15,821	29,896
Exploration	11,368	19,462	24,707	36,055
Abandonment and impairment of unproved properties	40,954	3,474	60,526	5,598
General and administrative	29,103	23,938	54,013	41,350
Deferred compensation plan	756	7,539	13,190	28,150
Interest expense	29,555	23,842	56,184	46,988
Depletion, depreciation and amortization	88,713	72,115	173,033	142,248
Total costs and expenses	242,841	203,654	467,843	400,463
Loss from operations	(62,409)	(51,851)	(10,974)	(43,322)
Income tax expense (benefit)				
Current	619	949	619	1,835
Deferred	(23,145)	(20,445)	(4,318)	(17,651)
Total income tax benefit	(22,526)	(19,496)	(3,699)	(15,816)
Net loss	$ (39,883)	$ (32,355)	$ (7,275)	$ (27,506)
Loss per common share:				
Basic	$ (0.26)	$ (0.22)	$ (0.05)	$ (0.18)
Diluted	$ (0.26)	$ (0.22)	$ (0.05)	$ (0.18)

Dividends per common share	$ 0.04	$ 0.04	$ 0.08	$ 0.08
Weighted average common shares outstanding:				
Basic	154,389	150,772	154,056	149,215
Diluted	154,389	150,772	154,056	149,215

See accompanying notes.

Table of Contents

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

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008 (Restated)
Operating activities:		
Net loss	$ (7,275)	$ (27,506)
Adjustments to reconcile net cash provided from operating activities:		
Loss (gain) from equity method investments	5,526	(19)
Deferred income tax benefit	(4,318)	(17,651)
Depletion, depreciation and amortization	173,033	142,248
Exploration dry hole costs	131	9,256
Mark-to-market on oil and gas derivatives not designated as hedges	30,070	297,501
Abandonment and impairment of unproved properties	60,526	5,598
Unrealized derivative loss	97	2,691
Deferred and stock-based compensation	32,794	43,601
Amortization of deferred financing costs and other	2,333	1,488
Loss (gain) on sale of assets and other	1,943	(19,972)
Changes in working capital:		
Accounts receivable	46,453	(94,657)
Inventory and other	(2,154)	(29,839)
Accounts payable	(72,008)	22,384
Accrued liabilities and other	1,283	9,739
Net cash provided from operating activities	268,434	344,862
Investing activities:		
Additions to oil and gas properties	(275,999)	(407,313)
Additions to field service assets	(14,849)	(19,895)
Acreage purchases	(107,321)	(404,922)
Investment in equity method investments	(6,400)	(10,800)
Other assets	9,079	
Proceeds from disposal of assets	182,122	66,660
Purchase of marketable securities held by the deferred compensation plan	(3,605)	(5,848)
Proceeds from the sales of marketable securities held by the deferred compensation plan	1,981	3,320
Net cash used in investing activities	(214,992)	(778,798)
Financing activities:		
Borrowing on credit facilities	451,000	678,000
Repayment on credit facilities	(741,000)	(775,500)
Dividends paid	(12,541)	(12,196)
Debt issuance costs	(6,161)	(5,510)

Issuance of subordinated notes	285,201	250,000
Issuance of common stock	6,002	288,073
Cash overdrafts	(38,212)	2,891
Proceeds from the sales of common stock held by the deferred compensation plan	3,683	4,306
Purchases of common stock held by the deferred compensation plan and other treasury stock purchases	(15)	(73)
Net cash (used in) provided from financing activities	(52,043)	429,991
Increase (decrease) in cash and equivalents	1,399	(3,945)
Cash and equivalents at beginning of period	753	4,018
Cash and equivalents at end of period	$ 2,152	$ 73

See accompanying notes.

5

Table of Contents

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008 (Restated)	2009	2008 (Restated)
Net loss	$ (39,883)	$ (32,355)	$ (7,275)	$ (27,506)
Other comprehensive (loss) income:				
Realized loss (gain) on hedge derivative contract settlements reclassified into earnings from other comprehensive (loss) income	(33,488)	30,975	(65,822)	27,762
Change in unrealized deferred hedging gains (losses)	(3,000)	(200,957)	43,183	(282,726)
Total comprehensive loss	$ (76,371)	$ (202,337)	$ (29,914)	$ (282,470)

See accompanying notes.

RANGE RESOURCES CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

(1) ORGANIZATION AND NATURE OF BUSINESS

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

(2) BASIS OF PRESENTATION

These interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Range Resources Corporation 2008 Annual Report on Form 10-K filed on February 25, 2009. 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. We have evaluated events or transactions through July 22, 2009 in conjunction with our preparation of these financial statements.

We adhere to Statement of Financial Accounting Standards (SFAS) No. 19 Financial Accounting and Reporting by Oil and Gas Producing Companies, for recognizing impairment of capitalized costs related to unproved properties. These costs are capitalized and periodically evaluated (at least quarterly) as to recoverability based on changes brought about by economic factors and potential shifts in business strategy employed by management. We consider time, geologic and engineering factors to evaluate the need for impairment of these costs. We continue to experience an increase in lease expirations and impairment expense caused by (1) current economic conditions which have impacted our future drilling plans thereby increasing the amount of expected lease expirations and (2) the expansion of our unproved property positions in new shale plays. As economic conditions change and we continue to evaluate unproved properties, our estimates of expirations likely will change and we may increase or decrease impairment expense. We recorded abandonment and impairment expense in the first six months of 2009 of $60.5 million compared to $5.6 million in the same period of the prior year. In the second quarter of 2009, we recorded abandonment and impairment expense of $41.0 million, which includes the expiration of certain significant Barnett Shale leases.

In second quarter 2009, we identified certain leases amounting to $8.2 million that expired in 2006, 2007, and 2008, which were not expensed as required. Based on Staff Accounting Bulletin No. 108 (SAB 108), we have determined that these amounts are immaterial to each of the time periods affected and, therefore, we are not required to amend our previously filed reports. However, if these adjustments were recorded in 2009, we believe the impact could be material to this year. Therefore, we plan to adjust our previously reported results for 2006, 2007, and 2008 for these immaterial amounts as required by SAB 108. Such previous periods will be restated upon the next filing of our annual consolidated financial statements. In addition to recording additional lease expirations, we plan to make four other adjustments to prior year numbers to correct other immaterial items, which included the following adjustments: (1) tax expense of $3.5 million for discrete tax items recorded in 2008 related to 2007 (2) expense for volumetric ineffectiveness related to our derivative positions of $1.7 million recorded in 2008 related to 2007 (3) dry hole expense of $2.4 million not recorded in 2007 and (4) deferred compensation income of $7.1 million recorded in 2007 related to 2006 and prior years. The balance sheet as of December 31, 2008 has been adjusted to reflect the cumulative impact of such errors. As a result, oil and gas properties decreased by $10.7 million, deferred tax liability decreased $4.2 million and retained earnings decreased by $6.5 million. For additional information, see Footnote 18.

(3) NEW ACCOUNTING STANDARDS

In February 2008, the Financial Accounting Standards Board (FASB) issued staff position (FSP) SFAS No. 157-2 which delayed the effective date of SFAS No. 157 for all non-financial assets and non-financial liabilities except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). This deferral of SFAS No. 157 primarily applied to our asset retirement obligation (ARO), which uses fair value measures at the date incurred to determine our liability and any property impairments that may occur. We adopted FSP SFAS No. 157-2 effective January 1, 2009 and the adoption did not have a material effect on our consolidated results of operations.

In June 2008, the FASB issued Staff Position No. EITF 03-6-1 Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities, (FSP EITF 03-6-1) which provides that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and, therefore, need to be included in the earnings allocation in computing earnings per share under the two class method. We adopted FSP EITF 03-6-1 on January 1, 2009 with no impact on our reported earnings per share.

In March 2008, the FASB issued SFAS No. 161, Disclosure about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133. SFAS No. 161 amends and expands the disclosure requirements of SFAS No. 133 with the intent to provide users of financial statements with an enhanced understanding of: (i) how and why any entity uses derivative instruments; (ii) how derivative instruments and related hedged items are accounted for under SFAS No. 133 and its related interpretations; and (iii) how derivative instruments and related hedged items affect an entity s financial position, financial performance and cash flows. We adopted SFAS No. 161 on January 1, 2009. See Note 11 for additional disclosures required by SFAS No. 161.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations. SFAS No. 141(R) replaces SFAS No. 141. The statement retains the purchase method of accounting for acquisitions, but requires a number of changes, including changes in the way assets and liabilities are recognized in the purchase method of accounting. It changes the recognition of assets acquired and liabilities assumed arising from contingencies, requires the capitalization of in-process research and development at fair value, and requires the expensing of acquisition-related costs as incurred. The statement will apply prospectively to business combinations occurring in our fiscal year beginning January 1, 2009. The adoption of SFAS No. 141(R) did not have an effect on our reported financial position or earnings.

In April 2009, two related FASB Staff Positions were issued:

FASB Staff Position (FSP) No. FAS 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments, (FSP FAS 107-1)

FSP No. FAS 157-4, Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly, (FSP FAS 157-4)

FSP FAS 107-1 amends SFAS No. 107 and Accounting Principles Board (APB) Opinion No. 28 to require disclosures about fair value of financial instruments in interim reporting periods for publicly traded companies. FSP FAS 157-4 provides additional guidance for estimating fair value in accordance with SFAS No. 157 when the volume and level of activity for the asset or liability has significantly decreased. It also includes guidance on identifying circumstances that indicate a transaction is not orderly. Additional disclosures are also required. We adopted the provisions of the FSP s for the period ending June 30, 2009. The adoption of these FSP s did not have an impact on our financial position or results of operations.

In May 2009, the FASB issued SFAS No. 165, Subsequent Events. SFAS No. 165 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. We adopted SFAS No. 165 for the period ending June 30, 2009, which did not have an impact on our financial position or results of operations.

(4) DISPOSITIONS

In second quarter 2009, we sold certain oil properties in West Texas for proceeds of $182.0 million. The proceeds from the sale of these oil properties were credited to oil and gas properties, with no gain or loss recognized, as the disposition did not materially impact the depletion rate of the remaining properties in the amortization base. In first quarter 2008, we sold East Texas properties for proceeds of $64.4 million and recorded a gain of $20.2 million.

(5) INCOME TAXES

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008 (Restated)	2009	2008
Income tax benefit	$(22,526)	$(19,496)	$(3,699)	$(15,816)
Effective tax rate	36.1%	37.6%	33.7%	36.5%

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 (loss), except for discrete items. Income taxes for discrete items are computed and recorded in the period that the specific transaction occurs. For the three months ended June 30, 2009 and 2008, 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. For the six months ended June 30, 2009, our overall effective tax rate on income from operations was different than the statutory rate of 35% due primarily to state income taxes, valuation allowance and permanent differences. For the six months June 30, 2008, our overall effective tax rate on income from operations was different than the statutory rate due primarily to state income taxes. We expect our effective tax rate to be approximately 37% for the remainder of 2009.

At December 31, 2008, we had regular tax net operating loss (NOL) carryforwards of $160.4 million and alternative minimum tax (AMT) NOL carryforwards of $92.5 million that expire between 2012 and 2027. Our deferred tax asset related to regular NOL carryforwards at December 31, 2008 was $10.7 million, net of the SFAS No. 123(R) deduction for unrealized benefits. At December 31, 2008, we have AMT credit carryforwards of $1.8 million that are not subject to limitation or expiration.

(6) EARNINGS (LOSS) PER COMMON SHARE

Basic income (loss) per share is based on weighted average number of common shares outstanding. Diluted income per share includes exercise of stock options, stock appreciation rights and restricted shares, provided the effect is not anti-dilutive. The following table sets forth the computation of basic and diluted earnings (loss) per common share (in thousands except per share amounts):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008 (Restated)	2009	2008 (Restated)
Numerator:				
Net loss	$ (39,883)	$ (32,355)	$ (7,275)	$ (27,506)
Denominator:				
Weighted average common shares outstanding basic	154,389	150,772	154,056	149,215
Effect of dilutive securities:				
Employee stock options, SARs and stock held in the deferred compensation plan				
Weighted average common shares diluted	154,389	150,772	154,056	149,215
Loss per common share:				
Basic net loss	$ (0.26)	$ (0.22)	$ (0.05)	$ (0.18)
Diluted net loss	$ (0.26)	$ (0.22)	$ (0.05)	$ (0.18)

The weighted average common shares basic amount excludes 2.4 million shares at June 30, 2009 and 2.2 million shares at June 30, 2008, of restricted stock that is held in our deferred compensation plan (although all restricted stock is issued and outstanding upon grant). Due to our net loss from operations for the three months and the six months ended June 30, 2009, we excluded all 10.4 million outstanding stock options/SARs and restricted stock because the effect would have been anti-dilutive. Due to our net loss from operations for the three months and the six months ended June 30, 2008, we excluded all 10.0 million outstanding stock options/SARs and restricted stock because the effect would have been anti-dilutive.

(7) SUSPENDED EXPLORATORY WELL COSTS

The following table reflects the changes in capitalized exploratory well costs for the six months ended June 30, 2009 and the year ended December 31, 2008 (in thousands):

	June 30,	December 31,

	2009	2008
Beginning balance at January 1	$ 47,623	$ 15,053
Additions to capitalized exploratory well costs pending the determination of proved reserves	20,509	43,968
Reclassifications to wells, facilities and equipment based on determination of proved reserves	(1,288)	(3,847)
Capitalized exploratory well costs charged to expense		(7,551)
Balance at end of period	66,844	47,623
Less exploratory well costs that have been capitalized for a period of one year or less	(48,020)	(41,681)
Capitalized exploratory well costs that have been capitalized for a period greater than one year	$ 18,824	$ 5,942
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	8	3

The $66.8 million of capitalized exploratory well costs at June 30, 2009 was incurred in 2009 ($18.5 million), in 2008 ($42.4 million) and in 2007 ($5.9 million). Of the eight projects that have exploratory costs capitalized for more than one year, seven projects are Marcellus Shale wells.

Table of Contents

(8) INDEBTEDNESS

We had the following debt outstanding as of the dates shown below (in thousands) (bank debt interest rate at June 30, 2009 is shown parenthetically). No interest expense was capitalized during the three months or the six months ended June 30, 2009 and 2008.

	June 30, 2009	December 31, 2008
Bank debt (2.1%)	$ 403,000	$ 693,000
Subordinated debt:		
7.375% Senior Subordinated Notes due 2013, net of discount	198,161	197,968
6.375% Senior Subordinated Notes due 2015	150,000	150,000
7.5% Senior Subordinated Notes due 2016, net of discount	249,616	249,595
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	285,357	
Other		105
Total debt	$ 1,786,134	$ 1,790,668
Estimated fair value[(1)]	$ 1,725,259	$ 1,621,793

(1) The book value of our bank debt approximates fair value because of its floating rate structure. The fair value of our senior subordinated debt is based on quoted end of period market prices.

Bank Debt

In October 2006, we entered into an amended and restated revolving bank facility, which we refer to as our bank debt or our bank credit facility, which is secured by substantially all of our assets. The bank credit facility provides for an initial commitment equal to the lesser of the facility amount or the borrowing base. On June 30, 2009, 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 each April and October and for event-driven unscheduled redeterminations. Our current bank group is comprised of twenty-six commercial banks each holding between 2.4% and 5.0% of the total facility. Of those twenty-six banks, thirteen are domestic banks and thirteen are foreign banks or wholly owned subsidiaries of foreign banks. The facility amount may be increased up to the borrowing base amount with twenty days notice, subject to payment of a mutually acceptable commitment fee to those banks agreeing to participate in the facility amount increase. At June 30, 2009, the outstanding balance under the bank credit facility was

$403.0 million and there was $847.0 million of borrowing capacity available under the facility amount. The loan matures October 25, 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 LIBO 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 2.5% for the three months ended June 30, 2009 compared to 4.8% for the three months ended June 30, 2008. The weighted average interest rate on the bank credit facility was 2.6% for the six months ended June 30, 2009 compared to 4.9% in the same period of the prior year. A commitment fee is paid on the undrawn balance based on an annual rate of between 0.375% and 0.50%. At June 30, 2009, the commitment fee was 0.375% and the interest rate margin was 1.75% on our LIBOR loans. At July 20, 2009, the interest rate (including applicable margin) was 2.3%.

Senior Subordinated Notes

In May 2009, we issued $300.0 million aggregate principal amount of 8.0% senior subordinated notes due 2019 (8.0% Notes). The 8.0% Notes were issued at a discount, which is being amortized over the life of the 8.0% Notes due 2019. Interest on the 8.0% Notes is payable semi-annually, in May and November, and is guaranteed by certain of our subsidiaries. We may redeem the 8.0% Notes, in whole or in part, at any time on or after May 15, 2014, at redemption prices of 104.0% of the principal amount as of May 15, 2014 and declining to 100.0% on May 15, 2017 and thereafter.

Before May 15, 2012, we may redeem up to 35% of the original aggregate principal amount of the 8.0% Notes at a redemption price equal to 108.0% of the principal amount thereof, plus accrued and unpaid interest, if any, with the proceeds of certain equity offerings, provided that at least 65% of the original aggregate principal amount of the 8.0% Notes remain outstanding immediately after the occurrence of such redemption and also provided such redemption shall occur within 60 days of the date of the closing of the equity offering.

Debt Covenants

Our bank credit facility contains negative covenants that limit our ability, among other things, to pay cash dividends, incur additional indebtedness, sell assets, enter into certain hedging contracts, change the nature of our business or operations, merge, consolidate, or make investments. In addition, we are required to maintain a ratio of debt to EBITDAX (as defined in the credit agreement) of no greater than 4.0 to 1.0 and a current ratio (as defined in the credit agreement) of no less than 1.0 to 1.0. We were in compliance with our covenants under the bank credit facility at June 30, 2009.

The indentures governing our senior subordinated notes contain various restrictive covenants that are substantially identical and may limit our ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, enter into transactions with affiliates, or change the nature of our business. At June 30, 2009, we were in compliance with these covenants.

(9) ASSET RETIREMENT OBLIGATIONS

Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives. Significant inputs used in determining such obligations include estimates of plugging and abandonment costs, estimated future inflation rates and well life. A reconciliation of our liability for plugging, abandonment and remediation costs for the six months ended June 30, 2009 is as follows (in thousands):

	Six Months Ended June 30, 2009
Beginning of period	$ 83,457
Liabilities incurred	915
Liabilities settled	(450)
Liabilities sold	(7,287)
Accretion expense	2,623
Change in estimate	2,550
End of period	$ 81,808

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

(10) CAPITAL STOCK

We have authorized capital stock of 485 million shares, which includes 475 million shares of common stock and 10 million shares of preferred stock. The following is a summary of changes in the number of common shares outstanding since the beginning of 2008:

	Six Months Ended June 30, 2009	Year Ended December 31, 2008
Beginning balance	155,375,487	149,511,997
Public offering		4,435,300

Stock options/SARs exercised	797,084	1,339,536
Restricted stock grants	475,306	167,054
Treasury shares		(78,400)
Issued for unproved property purchases	373,623	
Ending balance	157,021,500	155,375,487

Table of Contents

Treasury Stock

The Board of Directors has approved up to $10.0 million of repurchases of common stock based on market conditions and opportunities. 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. These contracts consist of collars and fixed price swaps. We do not utilize complex derivatives such as swaptions, knockouts or extendable swaps. At June 30, 2009, we had open swap contracts covering 17.0 Bcf of gas at prices averaging $7.40 per mcf. We also had collars covering 61.3 Bcf of gas at weighted average floor and cap prices of $6.64 to $7.85 per mcf and 1.5 million barrels of oil at weighted average floor and cap prices of $64.01 to $76.00 per barrel. Their fair value, represented by the estimated amount that would be realized upon termination, based on a comparison of the contract prices and a reference price, generally New York Mercantile Exchange (NYMEX), on June 30, 2009, was a net unrealized pre-tax gain of $169.4 million. These contracts expire monthly through December 2010.

The following table sets forth our derivative volumes and average hedge prices as of June 30, 2009:

Period	Contract Type	Volume Hedged	Average Hedge Price
Natural Gas			
2009	Swaps	92,351 Mmbtu/day	$ 7.40
2009	Collars	194,918 Mmbtu/day	$ 7.46-$8.15
2010	Collars	69,671 Mmbtu/day	$ 5.50-$7.43
Crude Oil			
2009	Collars	8,000 bbl/day	$64.01-$76.00

Under SFAS No. 133, every derivative instrument is required to be recorded on the balance sheet as either an asset or a liability measured at its fair value. Fair value is generally determined based on the difference between the fixed contract price and the underlying estimated market price at the determination date. Changes in the fair value of effective cash flow hedges are recorded as a component of Accumulated other comprehensive income (loss), (AOCI) which is later transferred to earnings when the underlying physical transaction occurs. Our AOCI at June 30, 2009 and December 31, 2008 relate solely to our derivative activities. If the derivative does not qualify as a hedge or is not designated as a hedge, the change in fair value of the derivative is recognized in earnings. As of June 30, 2009, an unrealized pre-tax derivative gain of $87.1 million was recorded in AOCI. This gain is expected to be reclassified into earnings in 2009 ($84.5 million) and 2010 ($2.6 million). The actual reclassification to earnings will be based on market prices at the contract settlement date.

For those derivative instruments that qualify for hedge accounting, settled transaction gains and losses are determined monthly, and are included as increases or decreases to oil and gas sales in the period the hedged production is sold. Oil and gas sales includes $53.2 million of gains in the three months ended June 30, 2009 compared to losses of $50.0 million in the three months ended June 30, 2008 related to settled hedging transactions. For the six months ended June 30, 2009, oil and gas sales include $104.5 million of gains compared to losses of $44.8 million in the same period of the prior period related to settled hedging transactions. Any ineffectiveness associated with these hedges is reflected in the statement of operations caption called Derivative fair value income (loss). 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 June 30, 2009 includes ineffective unrealized gains of $356,000 compared to unrealized gains of $558,000 in the same period of 2008. The six months ended June 30, 2009 includes ineffective unrealized losses of $97,000 compared to unrealized losses of

$2.7 million in the same period of 2008.

To designate a derivative as a cash flow hedge, we document at the hedge s inception our assessment that the derivative will be highly effective in offsetting expected changes in cash flows from the item hedged. This assessment, which is updated at least quarterly, is generally based on the most recent relevant historical correlation between the derivative and the item hedged. The ineffective portion of the hedge is calculated as the difference between the change in fair value of the derivative and the estimated change in cash flows from the item hedged. If, during the derivative s term, we determine the hedge is no longer highly effective, hedge accounting is prospectively discontinued and any remaining unrealized gains or losses, based on the effective portion of the derivative at that date, are reclassified to earnings as oil or gas sales when the underlying transaction occurs. If it is determined that the designated hedge transaction is not probable to occur, any unrealized gains or losses are recognized immediately in the statement of operations as a Derivative fair value income or loss. During the first six months of 2009, there were gains of $5.4 million reclassified into earnings as a result of the discontinuance of hedge accounting treatment for our derivatives. In July 2009, we liquidated four oil commodity contracts and received proceeds of $119,000.

Some of our derivatives do not qualify for hedge accounting but are, to a degree, an economic offset to our commodity price exposure. 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 the income statement caption called Derivative fair value income (loss) (see table below).

In addition to the swaps and collars discussed above, we have entered into basis swap agreements, which do not qualify for hedge accounting and are marked to market. The price we receive for our gas production can be more or less than the NYMEX price because of adjustments for delivery location (basis), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively fix a portion of our basis adjustments. The fair value of the basis swaps was a net unrealized pre-tax loss of $4.5 million at June 30, 2009 and these swaps expire through 2011.

Derivative Fair Value Income (Loss)

The following table presents information about the components of derivative fair value income (loss) in the three months and the six months ended June 30, 2009 and 2008 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008 (Restated)	2009	2008 (Restated)
Hedge ineffectiveness realized	$ 1,081	$ (490)	$ 1,578	$ 215
unrealized	356	558	(97)	(2,691)
Change in fair value of derivatives that do not qualify for hedge accounting[a]	(61,595)	(162,280)	(30,070)	(297,501)
Realized gain (loss) on settlements gas[a] [b]	48,370	(28,256)	86,742	(11,672)
Realized gain (loss) on settlements oil[a] [b]	1,932	(6,216)	7,538	(8,802)
Derivative fair value (loss) income	$ (9,856)	$ (196,684)	$ 65,691	$ (320,451)

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

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

The combined fair value of derivatives included in our consolidated balance sheets as of June 30, 2009 and December 31, 2008 is summarized below (in thousands). We conduct derivative activities with thirteen financial institutions, eleven 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. The assets and liabilities are netted where derivatives with both gain and loss positions are held by a single counterparty.

	June 30, 2009	December 31, 2008
Derivative assets:		
Natural gas swaps	$ 53,455	$ 57,280
collars	118,584	121,781
basis swaps	71	12,434
Crude oil collars	(2,254)	35,166
	$ 169,856	$ 226,661
Derivative liabilities:		
Natural gas swaps	$	$
collars	(99)	
basis swaps	(4,592)	(10)
Crude oil collars	(255)	
	$ (4,946)	$ (10)

Table of Contents

We adopted SFAS No. 161 at the beginning of 2009 and the expanded disclosures required by SFAS No. 161 are presented below. The table below provides data about the carrying values of derivatives that qualify for hedge accounting and derivatives that do not qualify for hedge accounting (in thousands):

	June 30, 2009			December 31, 2008		
	Assets	(Liabilities)		Assets	(Liabilities)	
	Carrying Value	Carrying Value	Net Carrying Value	Carrying Value	Carrying Value	Net Carrying Value
Derivatives that qualify for cash flow hedge accounting:						
Collars[1]	$ 93,198	$ (676)	$ 92,522	$ 124,193	$	$ 124,193
	$ 93,198	$ (676)	$ 92,522	$ 124,193	$	$ 124,193
Derivatives that do not qualify for hedge accounting:						
Swaps[1]	$ 53,455	$	$ 53,455	$ 57,280	$	$ 57,280
Collars[1]	24,853	(1,399)	23,454	32,754		32,754
Basis swaps[1]	2,663	(7,184)	(4,521)	12,481	(57)	12,424
	$ 80,971	$ (8,583)	$ 72,388	$ 102,515	$ (57)	$ 102,458

(1) Included in unrealized derivative gain/(loss) on our balance sheet.

The table below provides data about the amount of gains and losses related to cash flow derivatives that qualify for hedge accounting included in the balance sheet caption Accumulated other comprehensive income (AOCI) and in our statement of operations (in thousands):

	Amount of Gain/(Loss) Recognized in OCI (Effective Portion)		Amount of Gain (Loss) Reclassified from AOCI in Income (Effective Portion)[1]		Amount of Gain (Loss) in Income (Ineffective Portion)[2]	
	As of June 30,		Six Months Ended June 30,		Six Months Ended June 30,	
	2009	2008 (Restated)	2009	2008	2009	2008
Swap	$	$ (65,674)	$	$ 3,128	$	$ (1,457)
Collar	69,320	(390,378)	104,479	(47,905)	1,481	(1,019)
Income taxes	(26,137)	173,326	(38,657)	17,015		

Total	$ 43,183	$ (282,726)	$ 65,822	$ (27,762)	$ 1,481	$ (2,476)

(1) Swap and collar amounts are included in oil and gas sales in our statement of operations.

(2) Included in derivative fair value income (loss) in our statement of operations.

(12) FAIR VALUE MEASUREMENTS

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 table presents the fair value hierarchy table for assets and liabilities measured at fair value, on a recurring basis (in thousands):

	Fair Value Measurements at June 30, 2009 Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of June 30, 2009
Trading securities held in the deferred compensation plans	$ 37,320	$	$	$ 37,320
Derivatives swaps		53,455		53,455
collars		115,976		115,976
basis swaps		(4,521)		(4,521)

These items are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. Our trading securities in Level 1 are exchange-traded and measured at fair value with a market approach using June 30, 2009 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 the balance sheet category called other assets. We adopted SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities on January 1, 2008 which resulted in a reclassification of a $2.0 million pre-tax loss ($1.3 million after tax) related to our trading securities held in our deferred compensation plan from accumulated other comprehensive loss to retained earnings. 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 the statement of operations category called Deferred compensation plan expense. For the three months ended June 30, 2009, interest and dividends were $50,000 and mark-to-market was a gain of $4.9 million. For the three months ended June 30, 2008, interest and dividends were $79,000 and the mark-to-market was a loss of $666,000. For the six months ended June 30, 2009, interest and dividends were $93,000 and mark-to-market was a gain of $3.4 million. For the six months ended June 30, 2008, interest and dividends were $266,000 and the mark-to-market was a loss of $5.3 million.

Concentration of Credit Risk

Most of our receivables are from a diverse group of companies, including major energy companies, pipeline companies, local distribution companies, financial institutions and end-users in various industries. Letters of credit or other appropriate security are obtained as necessary to limit risk of loss. Our allowance for uncollectible receivables was $753,000 at June 30, 2009 and $954,000 at December 31, 2008. Commodity-based contracts expose us to the credit risk of nonperformance by the counterparty to the contracts. These contracts consist of collars and fixed price 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 thirteen financial institutions, eleven of which are secured lenders in our bank credit facility. Mitsui & Co. and J. Aron & Company are the two counterparties not in our bank group. At

June 30, 2009, our net derivative asset includes a payable to J. Aron & Company of $33,000 and a receivable from Mitsui & Co. for $9.9 million. None of our derivative contracts have margin requirements or collateral provisions that would require funding prior to the scheduled cash settlement date.

Table of Contents

(13) EMPLOYEE BENEFIT AND EQUITY PLANS

We have six equity-based stock plans, of which two are active. Under the active plans, incentive and nonqualified options, SARs and annual cash incentive awards may be issued to directors and employees 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, 2008	7,248,666	$ 26.15
Granted	1,693,405	36.76
Exercised	(941,562)	11.48
Expired/forfeited	(38,449)	37.72
Outstanding on June 30, 2009	7,962,060	$ 30.08

The following table shows information with respect to outstanding stock options and SARs at June 30, 2009:

	Outstanding			Exercisable	
Range of Exercise Prices	Shares	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
$1.29 $9.99	944,761	2.43	$ 3.39	944,761	$ 3.39
10.00 19.99	1,603,543	0.86	16.46	1,603,543	16.46
20.00 29.99	1,225,216	1.75	24.38	1,200,916	24.33
30.00 39.99	2,481,212	3.58	34.10	802,646	34.27
40.00 49.99	618,287	4.83	41.68	53,957	41.70
50.00 59.99	713,876	3.62	58.57	216,122	58.57
60.00 69.99	28,427	3.88	65.33	8,529	65.33
70.00 75.00	346,738	3.89	75.00	122,563	75.00
Total	7,962,060	2.73	$ 30.08	4,953,037	$ 22.41

The weighted average fair value of an option/SAR to purchase one share of common stock granted during 2009 was $15.39. The fair value of each stock option/SAR granted during 2009 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 1.5%; dividend yield of 0.4%; expected volatility of 59%; and an expected life of 3.5 years.

As of June 30, 2009, the aggregate intrinsic value (the difference in value between exercise and market price) of the awards outstanding was $115.0 million. The aggregate intrinsic value and weighted average remaining contractual life of stock option awards currently exercisable was $102.2 million and 1.9 years. As of June 30, 2009, the number of fully vested awards and awards expected to vest was 7.8 million. The weighted average exercise price and weighted average remaining contractual life of these awards was $29.80 and 2.7 years and the aggregate intrinsic value was $114.3 million. As of June 30, 2009, unrecognized compensation cost related to the awards was $37.1 million, which is expected to be recognized over a weighted average period of 1.4 years. Of the 8.0 million stock option/SARs outstanding at June 30, 2009, 1.8 million are stock options and 6.2 million are SARs.

Restricted Stock Grants

During the first six months of 2009, 532,900 shares of restricted stock (or non-vested shares) were issued to employees at an average price of $37.70 with a three-year vesting period and 22,700 shares were granted to our directors at an average price of $41.60 with immediate vesting. In the first six months of 2008, we issued 312,500 shares of restricted stock as compensation to employees at an average price of $65.84 with a three-year vesting period and 10,800 shares were granted to our directors at a price of $75.00 with immediate vesting. We recorded compensation expense related to restricted

Table of Contents

stock grants which is based upon the market value of the shares on the date of grant of $8.8 million in the first six months of 2009 compared to $7.4 million in the six-month period ended June 30, 2008. As of June 30, 2009, unrecognized compensation cost related to restricted stock awards was $30.0 million, which is expected to be recognized over the weighted average period of 1.5 years (excluding mark-to-market that would also be recognized over that same time period). All of our restricted stock grants are held in our deferred compensation plans (see discussion below). All awards granted have been issued at prevailing market prices at the time of the grant and the vesting of these shares is based upon an employee s continued employment with us.

A summary of the status of our non-vested restricted stock outstanding at June 30, 2009 is presented below:

	Shares	Weighted Average Grant Date Fair Value
Non-vested shares outstanding at December 31, 2008	473,547	$ 48.50
Granted	555,581	37.86
Vested	(248,096)	39.87
Forfeited	(1,976)	33.91
Non-vested shares outstanding at June 30, 2009	779,056	$ 43.70

Deferred Compensation Plan

In December 2004, we adopted the Range Resources Corporation Deferred Compensation Plan (2005 Deferred Compensation Plan). The 2005 Deferred Compensation Plan gives directors, officers and key employees the ability to defer all or a portion of their salaries and bonuses and invest such amounts in Range common stock or make other investments at the individual s discretion. The assets of the plan are held in a grantor trust, which we refer to as the Rabbi Trust, and are therefore available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. Our stock granted and held in the Rabbi Trust is treated as a liability award as employees are allowed to take withdrawals from the Rabbi Trust either in cash or in Range stock. The liability associated with the vested portion of the stock held in the Rabbi Trust is adjusted to fair value each reporting period by a charge or credit to deferred compensation plan expense on our consolidated statement of operations. The assets of the Rabbi Trust, other than Range common stock, are invested in marketable securities and reported at market value in other assets on our consolidated balance sheet. Changes in the market value of the securities are charged or credited to deferred compensation plan expense each quarter. The deferred compensation liability on our balance sheet reflects the vested market value of the marketable securities and stock held in the Rabbi Trust. We recorded non-cash, mark-to-market expense related to our deferred compensation plan of $13.2 million in the first six months of 2009 compared to mark-to-market expense of $28.1 million in the same period of 2008.

(14) SUPPLEMENTAL CASH FLOW INFORMATION

	Six Months Ended June 30,	
	2009	2008
	(in thousands)	
Non-cash investing and financing activities included:		
Asset retirement costs (removed) capitalized, net	$ (3,866)	$ 3,175
Unproved property purchased with stock	$ 15,920	$
Net cash provided from operating activities included:		
Interest paid	$ 51,185	$ 43,189
Income taxes paid	$ 507	$ 2,320

17

Table of Contents

(15) COMMITMENTS AND CONTINGENCIES

Transportation Contracts

We have entered firm transportation contracts with various pipelines. Under these contracts, we are obligated to transport minimum daily gas volumes, as calculated on a monthly basis, or pay for any deficiencies at a specified reservation fee rate. In most cases, our production committed to these pipelines is expected to exceed the minimum daily volumes provided in the contracts. As of June 30, 2009, future minimum transportation fees under our gas transportation commitments are as follows (in thousands):

2009 remaining	$ 17,774
2010	34,663
2011	34,180
2012	31,220
2013	30,349
2014	27,070
Thereafter	207,240
	$ 382,496

Litigation

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

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

	June 30, 2009 (in thousands)	December 31, 2008 (Restated)
Oil and gas properties:		
Properties subject to depletion	$ 5,370,529	$ 5,271,021
Unproved properties	791,305	757,959
Total	6,161,834	6,028,980
Accumulated depreciation, depletion and amortization	(1,337,153)	(1,186,934)
Net capitalized costs	$ 4,824,681	$ 4,842,046

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

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

	Six Months Ended	Year Ended

	June 30, 2009	December 31, 2008
	(in thousands)	
Acquisitions:		
Unproved leasehold	$	$ 99,446
Proved oil and gas properties	443	251,471
Asset retirement obligations		251
Acreage purchases	110,093	494,341
Development	243,125	729,268
Exploration:		
Drilling	31,678	133,116
Expense	22,753	63,560
Stock-based compensation expense	1,954	4,130
Gas gathering facilities	14,581	47,056
Subtotal	424,627	1,822,639
Asset retirement obligations	(3,866)	4,647
Total costs incurred	$ 420,761	$ 1,827,286

(a) Includes costs incurred whether capitalized or expensed.

Table of Contents

(18) RESTATEMENT OF PRIOR PERIODS

As further explained in Footnote 2, we plan to adjust previously reported results for 2006, 2007 and 2008 for immaterial errors as required by SAB 108. Additionally, we have restated the second quarter and the six months ended June 30, 2008 to reflect the impact of such errors. The following presents these adjustments in detail:

	1st Quarter 2008			2nd Quarter 2008			Six Months 2008		
	Previously Reported	Adjustments	Adjusted	Previously Reported	Adjustments	Adjusted	Previously Reported	Adjustments	Adjusted
Oil and gas sales	$ 307,384	$	$ 307,384	$ 347,622	$	$ 347,622	$ 655,006	$	$ 655,006
Transportation and gathering	1,129		1,129	1,224		1,224	2,353		2,353
Derivative fair value income	(123,767)		(123,767)	(198,410)	1,726	(196,684)	(322,177)	1,726	(320,451)
Other	20,592		20,592	(359)		(359)	20,233		20,233
Total revenues	205,338		205,338	150,077	1,726	151,803	355,415	1,726	357,141
Direct operating costs	32,950		32,950	37,228		37,228	70,178		70,178
Production and ad valorem taxes	13,840		13,840	16,056		16,056	29,896		29,896
Exploration	16,593		16,593	19,462		19,462	36,055		36,055
Abandonment & impairment of unproved properties	1,437	687	2,124	5,348	(1,874)	3,474	6,785	(1,187)	5,598
General and administrative expense	17,412		17,412	23,938		23,938	41,350		41,350
Deferred compensation plan	20,611		20,611	7,539		7,539	28,150		28,150
Interest expense	23,146		23,146	23,842		23,842	46,988		46,988
Depletion, depreciation and amortization	70,133		70,133	72,115		72,115	142,248		142,248
Total costs	196,122	687	196,809	205,528	(1,874)	203,654	401,650	(1,187)	400,463
Income (loss) from operations	9,216	(687)	8,529	(55,451)	3,600	(51,851)	(46,235)	2,913	(43,322)
Income tax expense									

(benefit)									
Current	886		886	949		949	1,835		1,835
Deferred	6,590	(3,796)	2,794	(21,818)	1,373	(20,445)	(15,228)	(2,423)	(17,651)
Total	7,476	(3,796)	3,680	(20,869)	1,373	(19,496)	(13,393)	(2,423)	(15,816)
Net income (loss)	$ 1,740	$ 3,109	$ 4,849	$ (34,582)	$ 2,227	$ (32,355)	$ (32,842)	$ 5,336	$ (27,506)
Earnings (loss) per share:									
Basic	$ 0.01	$ 0.02	$ 0.03	$ (0.23)	$ 0.01	$ (0.22)	$ (0.22)	$ 0.04	$ (0.18)
Diluted	$ 0.01	$ 0.02	$ 0.03	$ (0.23)	$ 0.01	$ (0.22)	$ (0.22)	$ 0.04	$ (0.18)

	Year Ended December 31, 2008			Year Ended December 31, 2007			Year Ended December 31, 2006		
	Previously Reported	Adjustments	Adjusted	Previously Reported	Adjustments	Adjusted	Previously Reported	Adjustments	Adjusted
Oil and gas sales	$ 1,226,560	$	$ 1,226,560	$ 862,537	$	$ 862,537	$ 599,139	$	$ 599,139
Transportation and gathering	4,577		4,577	2,290		2,290	2,422		2,422
Derivative fair value income	70,135	1,726	71,861	(7,767)	(1,726)	(9,493)	142,395		142,395
Other	21,675		21,675	5,031		5,031	856		856
Total revenues	1,322,947	1,726	1,324,673	862,091	(1,726)	860,365	744,812		744,812
Direct operating costs	142,387		142,387	107,499		107,499	81,261		81,261
Production and ad valorem taxes	55,172		55,172	42,443		42,443	36,415		36,415
Exploration	67,690		67,690	43,345	2,437	45,782	44,088		44,088
Abandonment & impairment of unproved properties	47,906	(551)	47,355	6,750	4,486	11,236	257	4,292	4,549
General and administration expense	92,308		92,308	69,670		69,670	49,886		49,886
Deferred compensation plan	(24,689)		(24,689)	28,332	7,106	35,438	6,873	(7,106)	(233)
Interest expense	99,748		99,748	77,737		77,737	55,849		55,849
	299,831		299,831	220,578		220,578	154,482		154,482

Depletion, depreciation and amortization									
Total costs	780,353	(551)	779,802	596,354	14,029	610,383	429,111	(2,814)	426,297
Income from continuing operations before tax	542,594	2,277	544,871	265,737	(15,755)	249,982	315,701	2,814	318,515
Income tax expense									
Current	4,268		4,268	320		320	1,912		1,912
Deferred	192,168	(2,605)	189,563	98,441	(2,454)	95,987	119,840	886	120,726
Total	196,436	(2,605)	193,831	98,761	(2,454)	96,307	121,752	886	122,638
Net income from continuing operations	346,158	4,882	351,040	166,976	(13,301)	153,675	193,949	1,928	195,877
Discontinued operations				63,593		63,593	(35,247)		(35,247)
Net income	$ 346,158	$ 4,882	$ 351,040	$ 230,569	$ (13,301)	$ 217,268	$ 158,702	$ 1,928	$ 160,630
Earnings per common share:									
Basic income from continuing operations	$ 2.29	$ 0.03	$ 2.32	$ 1.16	$ (0.09)	$ 1.07	$ 1.45	$ 0.01	$ 1.46
discontinued operations				0.44		0.44	(0.26)		(0.26)
net income	$ 2.29	$ 0.03	$ 2.32	$ 1.60	$ (0.09)	$ 1.51	$ 1.19	$ 0.01	$ 1.20
Earnings per common share:									
Diluted income from continuing operations	$ 2.22	$ 0.03	$ 2.25	$ 1.11	$ (0.09)	$ 1.02	$ 1.39	$ 0.01	$ 1.40
				0.43		0.43	(0.25)		(0.25)

discontinued operations																		
net income	$	2.22	$	0.03	$	2.25	$	1.54	$	(0.09)	$	1.45	$	1.14	$	0.01	$	1.15

Table of Contents

(19) ACCOUNTING STANDARDS NOT YET ADOPTED

In December 2008, the SEC announced that it had approved revisions to its oil and gas reporting disclosures. The new disclosure requirements include provisions that:

- Introduce a new definition of oil and gas producing activities. This new definition allows companies to include in their reserve base volumes from unconventional resources. Such unconventional resources include bitumen extracted from oil sands and oil and gas extracted from coal beds and shale formations.

- Report oil and gas reserves using an unweighted average price using the prior 12-month period, based on the closing prices on the first day of each month, rather than year-end prices. The SEC indicated that they will continue to communicate with the FASB staff to align their accounting standards with these rules. The FASB currently requires a single-day, year-end price for accounting purposes.

- Permit companies to disclose their probable and possible reserves on a voluntary basis. In the past, proved reserves were the only reserves allowed in the disclosures.

- Requires companies to provide additional disclosure regarding the aging of proved undeveloped reserves.

- Permit the use of reliable technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes.

- Replace the existing certainty test for areas beyond one offsetting drilling unit from a productive well with a reasonable certainty test.

- Require additional disclosures regarding the qualifications of the chief technical person who oversees the company s overall reserve estimation process. Additionally, disclosures regarding internal controls over reserve estimation, as well as a report addressing the independence and qualifications of its reserves preparer or auditor will be mandatory.

We will begin complying with the disclosure requirements in our annual report on Form 10-K for the year ending December 31, 2009. The new rules may not be applied to disclosures in quarterly reports prior to the first annual report in which the revised disclosures are required. We are currently in the process of evaluating the new requirements.

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

The following discussion should be read in conjunction with management s discussion and analysis contained in our 2008 Annual Report on Form 10-K, as well as the consolidated financial statements and notes thereto included in this Quarterly Report on Form 10-Q. Statements in our discussion may be forward-looking. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause future production, revenues and expenses to differ materially from our expectations. For additional risk factors affecting our business, see the information in Item 1A. Risk Factors, in our 2008 Annual Report on Form 10-K and subsequent filings. Except where noted, discussions in this report relate only to our continuing operations.

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 the 2008 Form 10-K except as updated below. We have identified the following critical accounting policies and estimates used in the preparation of our financial statements: accounting for oil and gas revenue, oil and gas properties, stock-based compensation, derivative financial instruments, asset retirement obligations and deferred taxes.

We adhere to SFAS No. 19 Financial Accounting and Reporting by Oil and Gas Producing Companies, for recognizing impairment of capitalized costs related to unproved properties. These costs are capitalized and periodically evaluated (at least quarterly) as to recoverability based on changes brought about by economic factors and potential shifts in business strategy employed by management. We consider time, geologic and engineering factors to evaluate the need for impairment of these costs. We continue to experience an increase in lease expirations and impairment expense caused by (1) current economic conditions, which have impacted our future drilling plans thereby increasing the amount of expected lease expirations, and (2) the rapid expansion of our unproved property positions in new shale plays. As economic conditions change and we continue to evaluate unproved properties, our estimates of expirations likely will change and we may increase or decrease impairment expense. We recorded abandonment and impairment expense in the first six months of 2009 of $60.5 million compared to $5.6 million in the same period of the prior year. In second quarter 2009, we recorded abandonment and impairment expense of $41.0 million, which includes the expiration of certain significant Barnett Shale leases.

Results of Continuing Operations

Overview

Total revenues increased $28.6 million, or 19% for second quarter 2009 over the same period of 2008. The increase includes a $186.8 million decrease in derivative fair value losses offset by a $155.1 million, or 45% decrease in oil and gas sales. Oil and gas sales vary due to changes in volumes of production sold and realized commodity prices. Due to the extreme volatility in oil and gas prices, realized prices dropped sharply from the prior year, which was partially offset by an increase in production. For second quarter 2009, production increased 14% from the same period of the prior year while realized prices declined 32% from the same quarter of the prior year. For the six months ended June 30, 2009, production increased 13% from the same period of the prior year while realized prices declined 31%. We believe oil and gas prices will remain volatile and will be affected by, among other things, weather, the U.S. and worldwide economy, new regulations and the level of oil and gas production in North America and worldwide.

Despite a 14% increase in production volumes, total oil and gas sales declined 45% when compared to the same quarter of the prior year. The oil and gas commodity price decline, which began during the second half of 2008, has continued through the first half of 2009 especially with regard to natural gas prices. With the lower commodity price environment, we have focused our efforts on improving our operating efficiency. These efforts resulted in a lower direct operating expense per mcfe of 18% for the second quarter and 11% for the six months ended June 30, 2009 when compared to the same periods of the prior year. However, as we continue to expand our Marcellus Shale team to meet the needs of this developing asset, we have seen upward pressure on our general and administrative costs per mcfe. We also continue to see higher fixed interest expense per mcfe due to the issuances of new senior subordinated notes at higher interest rates than our bank credit facility.

Table of Contents

Oil and Gas Sales, Production and Realized Price Calculation

Our oil and gas sales vary from quarter to quarter as a result of changes in realized commodity prices and volumes of production sold. Hedges included in oil and gas sales reflect settlement on those derivatives that qualify for hedge accounting. Cash settlement of derivative contracts that are not accounted for as hedges are included in the statement of operations caption called Derivative fair value income (loss). In the second quarter and the six months ended June 30, 2009, we continue to experience deteriorating basis differentials in the Midcontinent and West Texas areas caused by an over supply of gas in these regions. The following table summarizes the primary components of oil and gas sales for the three months and the six months ended June 30, 2009 and 2008 (in thousands):

	Three Months Ended June 30,				Six Months Ended June 30,			
	2009	2008	Change	%	2009	2008	Change	%
Oil wellhead	$ 39,943	$ 99,715	$ (59,772)	(60%)	$ 68,023	$ 171,134	$ (103,111)	(60%)
Oil hedges realized	2,642	(33,033)	35,675	108%	12,007	(48,425)	60,432	125%
Total oil sales	42,585	66,682	(24,097)	(36%)	80,030	122,709	(42,679)	(35%)
Gas wellhead	86,722	279,054	(192,332)	(69%)	203,642	493,570	(289,928)	(59%)
Gas hedges realized	50,514	(16,926)	67,440	398%	92,472	3,648	88,824	2,435%
Total gas sales	137,236	262,128	(124,892)	(48%)	296,114	497,218	(201,104)	(40%)
NGL	12,702	18,812	(6,110)	(32%)	19,568	35,079	(15,511)	(44%)
Combined wellhead	139,367	397,581	(258,214)	(65%)	291,233	699,783	(408,550)	(58%)
Combined hedges	53,156	(49,959)	103,115	206%	104,479	(44,777)	149,256	333%
Total oil and gas sales	$ 192,523	$ 347,622	$ (155,099)	(45%)	$ 395,712	$ 655,006	$ (259,294)	(40%)

Our production continues to grow through continued drilling success as we place new wells into production. For second quarter 2009, our production volumes increased, from the same period of the prior year, 19% in our Appalachian Area, 11% in our Southwestern Area and decreased 4% in our Gulf Coast Area. For the six months ended June 30, 2009, our production volumes increased, from the same period of the prior year, 17% in our Appalachia Area, 10% in our Southwestern Area and 3% in our Gulf Coast Area. Our production for the three months and the six months ended June 30, 2009 and 2008 is shown below:

	Three Months Ended June 30,		Six Months Ended, June 30,	
	2009	2008	2009	2008
Production:				
Crude oil (bbls)	731,244	829,144	1,453,204	1,583,689

NGLs (bbls)	525,993	335,231	949,254	647,731
Natural gas (mcf)	31,905,593	27,653,005	62,457,926	54,975,779
Total (mcfe)[a]	39,449,015	34,639,255	76,872,674	68,364,299
Average daily production:				
Crude oil (bbls)	8,036	9,111	8,029	8,702
NGLs (bbls)	5,780	3,684	5,244	3,559
Natural gas (mcf)	350,611	303,879	345,071	302,065
Total (mcfe)[a]	433,506	380,651	424,711	375,628

[a] Oil and NGLs are converted at the rate of one barrel equals six mcfe.

Table of Contents

Our average realized price (including all derivative settlements) received for oil and gas was $6.18 per mcfe in second quarter 2009 compared to $9.03 per mcfe in the same period of the prior year. Our average realized price calculation (including all derivative settlements) includes all cash settlement for derivatives, whether or not they qualify for hedge accounting. Average price calculations for the three months and the six months ended June 30, 2009 and 2008 are shown below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Average sales prices (wellhead):				
Crude oil (per bbl)	$54.62	$120.26	$46.80	$108.06
NGLs (per bbl)	$24.15	$ 56.12	$20.61	$ 54.16
Natural gas (per mcf)	$ 2.72	$ 10.09	$ 3.26	$ 8.98
Total (per mcfe)[a]	$ 3.53	$ 11.48	$ 3.79	$ 10.24
Average realized price (including derivatives that qualify for hedge accounting):				
Crude oil (per bbl)	$58.23	$ 80.42	$55.07	$ 77.48
NGLs (per bbl)	$24.15	$ 56.12	$20.61	$ 54.16
Natural gas (per mcf)	$ 4.30	$ 9.48	$ 4.74	$ 9.04
Total (per mcfe)[a]	$ 4.88	$ 10.04	$ 5.15	$ 9.58
Average realized price (including all derivative settlements):				
Crude oil (per bbl)	$60.88	$ 72.34	$60.26	$ 71.34
NGLs (per bbl)	$24.15	$ 56.12	$20.61	$ 54.16
Natural gas (per mcf)	$ 5.85	$ 8.46	$ 6.15	$ 8.85
Total (per mcfe)[a]	$ 6.18	$ 9.03	$ 6.39	$ 9.28
Average NYMEX prices[b]				
Oil (per bbl)	$59.77	$123.98	$51.54	$111.66
Natural gas (per mcf)	$ 3.59	$ 10.80	$ 4.21	$ 9.45

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

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

Derivative fair value income (loss) is a loss of $9.9 million in second quarter 2009 compared to a loss of $196.7 million in the same period of 2008. Some of our derivatives do not qualify for hedge accounting but are, to a degree, economic hedges of our commodity price exposure. These contracts are accounted for using the mark-to-market accounting method. All unrealized and realized gains and losses related to these contracts are included in the statement of operations caption Derivative fair value income (loss). We have also entered into basis swap agreements, which do not qualify for hedge accounting and are also marked to market. Not using hedge 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 our balance sheet caption Accumulated other comprehensive income (loss). Hedge ineffectiveness, also included in this statement of operations category, is associated with our hedging contracts that qualify for hedge accounting under SFAS No. 133.

Table of Contents

The following table presents information about the components of derivative fair value income (loss) for the three months and the six months ended June 30, 2009 and 2008 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Hedge ineffectiveness realized[(a)]	$ 1,081	$ (490)	$ 1,578	$ 215
unrealized[(a)]	356	558	(97)	(2,691)
Change in fair value of derivatives that do not qualify for hedge accounting[(a)]	(61,595)	(162,280)	(30,070)	(297,501)
Realized gain (loss) on settlements gas[(b)(c)]	48,370	(28,256)	86,742	(11,672)
Realized gain (loss) on settlements oil[(b)(c)]	1,932	(6,216)	7,538	(8,802)
Derivative fair value (loss) income	$ (9,856)	$ (196,684)	$ 65,691	$ (320,451)

(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 (including all derivative settlements).

Other revenue for second quarter 2009 decreased to a loss of $4.4 million from a loss of $359,000 in the same period of 2008. Second quarter 2009 includes a loss from equity method investments of $4.6 million compared to income of $294,000 in the same period of the prior year. Other revenue for the first six months of 2009 decreased to a loss of $6.2 million from a gain of $20.2 million in the same period of the prior year. The first six months of 2009 includes a loss from equity method investments of $5.5 million. The first six months of 2008 includes a gain on the sale of certain East Texas properties of $20.1 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 an mcfe basis for the three months and the six months ended June 30, 2009 and 2008:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2009	2008	Change	%	2009	2008	Change	%
Direct operating expense	$0.88	$1.07	$(0.19)	(18%)	$0.92	$1.03	$(0.11)	(11%)
Production and ad valorem tax expense	0.19	0.46	(0.27)	(59%)	0.21	0.44	(0.23)	(52%)
General and administrative expense	0.74	0.69	0.05	7%	0.70	0.60	0.10	17%
Interest expense	0.75	0.69	0.06	9%	0.73	0.69	0.04	6%
Depletion, depreciation and amortization expense	2.25	2.08	0.17	8%	2.25	2.08	0.17	8%

Direct operating expense declined $2.4 million in second quarter 2009 to $34.8 million. Increases in operating expenses as we add new wells and maintain production from existing properties were more than offset by lower workovers and lower overall industry costs. Our spending for direct operating expense (excluding workovers) is virtually unchanged for the three months and the six months ended June 30, 2009 despite higher production levels due to cost containment measures and lower overall industry costs. We incurred $931,000 ($0.02 per mcfe) of workover costs in second quarter 2009 versus $3.5 million ($0.10 per mcfe) in 2008. On a per mcfe basis, direct operating expenses for second quarter 2009 decreased $0.19 or 18% from the same period of 2008 with the decrease consisting primarily of lower workover costs ($0.08 per mcfe) and lower well service and utility costs. Direct operating expense was $70.4 million in the first six months of 2009 compared to $70.2 million in the same period of the prior year. We incurred $2.7 million ($0.03 per mcfe) of workover costs in the first six months of 2009 versus $5.4 million ($0.08 per mcfe) in 2008. On a per mcfe basis, direct operating expenses for the first six months of 2009 decreased $0.11 or 11% from the same time period of 2008 with the decrease consisting primarily of lower workover costs ($0.05 per mcfe), lower utility costs ($0.02 per mcfe) and lower well services costs. The following table summarizes direct operating expenses per mcfe for the three months and the six months ended June 30, 2009 and 2008:

Table of Contents

	Three Months Ended June 30,				Six Months Ended June 30,			
	2009	2008	Change	%	2009	2008	Change	%
Lease operating expense	$ 0.84	$ 0.95	$ (0.11)	(12%)	$ 0.87	$ 0.93	$ (0.06)	(6%)
Workovers	0.02	0.10	(0.08)	(80%)	0.03	0.08	(0.05)	(63%)
Stock-based compensation (non-cash)	0.02	0.02		%	0.02	0.02		%
Total direct operating expenses	$ 0.88	$ 1.07	$ (0.19)	(18%)	$ 0.92	$ 1.03	$ (0.11)	(11%)

Production and ad valorem taxes are paid based on market prices and not hedged prices. For the second quarter, these taxes decreased $8.5 million or 53% from the same period of the prior year due to the significant decline in wellhead prices. On a per mcfe basis, production and ad valorem taxes decreased to $0.19 in second quarter 2009 from $0.46 in the same period of 2008 primarily due to a 69% decrease in pre-hedge prices. For the first six months of 2009, these taxes decreased $14.1 million or 47% from the same period of the prior year due to the significant decline in pre-hedge prices, which declined 63%.

General and administrative expense for second quarter 2009 increased $5.2 million from the same period of the prior year due primarily to higher salaries and benefits ($2.4 million) from an increase in the number of employees as we continue the expansion of our Marcellus Shale team, higher stock-based compensation ($2.0 million) and higher office expenses, including rent and information technology. General and administrative expense for the six months 2009 increased $12.7 million or 31% from the same period of the prior year due primarily to higher salaries and benefits ($6.7 million), higher stock-based compensation ($3.6 million) and higher office expenses. 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 and six months ended June 30, 2009 and 2008:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2009	2008	Change	%	2009	2008	Change	%
General and administrative	$ 0.51	$ 0.49	$ 0.02	4%	$ 0.50	$ 0.43	$ 0.07	16%
Stock-based compensation (non-cash)	0.23	0.20	0.03	15%	0.20	0.17	0.03	18%
Total general and administrative expenses	$ 0.74	$ 0.69	$ 0.05	7%	$ 0.70	$ 0.60	$ 0.10	17%

Interest expense for second quarter 2009 increased $5.7 million from the same period of the prior year to $29.6 million due to the refinancing of certain debt from floating to higher fixed rates combined with higher overall debt balances. In May 2009, we issued $300.0 million of 8.0% senior subordinated notes due 2019, which added $3.1 million of interest costs in second quarter 2009. The proceeds from the issuance were used to retire lower interest bank debt, to better match the maturities of our debt with the life of our properties and to give us greater liquidity for the near term. Average debt outstanding on the bank credit facility for second quarter 2009 was $715.6 million compared to $352.3 million for the same period of the prior year and the weighted average interest rates were 2.5% in second quarter 2009 compared to 4.8% in the same period of the prior year. Interest expense for the six months ended June 30, 2009 increased $9.2 million or 20% also due to the refinancing of certain debt from floating to higher fixed rates and higher overall debt balances. Average debt outstanding on the bank credit facility for the first six months of 2009 was $751.4 million compared to $446.0 million for the first six months of 2008 and the weighted average interest rate was 2.6% in the first six months 2009 compared to 4.9% in the same period of 2008.

Depletion, depreciation and amortization (DD&A) increased $16.6 million, or 23%, to $88.7 million in second quarter 2009 with a 14% increase in production and an 8% increase in depletion rates. On a per mcfe basis, DD&A

increased from $2.08 in second quarter 2008 to $2.25 in second quarter 2009. In the first six months of 2009, DD&A increased $30.8 million to $173.0 million with a 13% increase in production and an 8% increase in depletion rates. The increase in DD&A per mcfe is related to increasing drilling costs, higher acquisition costs and the mix of our production. The following table summarizes DD&A expenses per mcfe for the three months and the six months ended June 30, 2009 and 2008:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2009	2008	Change	%	2009	2008	Change	%
Depletion and amortization	$ 2.10	$ 1.94	$ 0.16	8%	$ 2.10	$ 1.95	$ 0.15	8%
Depreciation	0.12	0.09	0.03	33%	0.12	0.09	0.03	33%
Accretion and other	0.03	0.05	(0.02)	(40%)	0.03	0.04	(0.01)	(25%)
Total DD&A expense	$ 2.25	$ 2.08	$ 0.17	8%	$ 2.25	$ 2.08	$ 0.17	8%

Table of Contents

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 and deferred compensation plan expenses. In the three months and the six months ended June 30, 2009 and 2008, stock-based compensation represents the amortization of restricted stock grants and expenses related to SAR grants. In second quarter 2009, stock-based compensation is a component of direct operating expense ($830,000), exploration expense ($893,000) and general and administrative expense ($8.9 million) for a total of $10.8 million. In second quarter 2008, stock-based compensation was a component of direct operating expense ($711,000), exploration expense ($1.0 million) and general and administrative expense ($7.0 million) for a total of $8.8 million. In the six months ended June 30, 2009, stock-based compensation is a component of directing operating expense ($1.6 million), exploration expense ($2.0 million) and general and administrative expense ($15.2 million) for a total of $19.1 million. In the six months ended June 30, 2008, stock based compensation is a component of direct operating expense ($1.3 million) exploration expense ($2.1 million) and general and administrative expense ($11.6 million) for a total of $15.2 million.

Exploration expense decreased $8.1 million in second quarter 2009 primarily due to lower dry hole and seismic costs. Exploration expense declined $11.3 million in the first six months 2009 due to lower dry hole and seismic costs. The following table details our exploration-related expenses for the three months and the six months ended June 30, 2009 and 2008 (in thousands):

	Three Months Ended June 30,				Six Months Ended June 30,			
	2009	2008	Change	%	2009	2008	Change	%
Dry hole expense	$ 8	$ 4,288	$ (4,280)	(100%)	$ 131	$ 9,256	$ (9,125)	(99%)
Seismic	5,717	9,782	(4,065)	(42%)	13,915	16,526	(2,611)	(16%)
Personnel expense	2,836	2,917	(81)	(3%)	5,705	5,555	150	3%
Stock-based compensation expense	893	1,019	(126)	(12%)	1,954	2,108	(154)	(7%)
Delay rentals and other	1,914	1,456	458	31%	3,002	2,610	392	15%
Total exploration expense	$ 11,368	$ 19,462	$ (8,094)	(42%)	$ 24,707	$ 36,055	$ (11,348)	(31%)

Abandonment and impairment of unproved properties expense was $41.0 million in second quarter 2009 compared to $3.5 million in the same period of the prior year. In the second quarter 2009, abandonment and impairment expense of $41.0 million includes the expiration of certain significant Barnett shale leases. We continue to experience increases in lease expirations and impairment expenses caused by (1) current economic conditions which have impacted our future drilling plans thereby increasing the amount of expected lease expirations and (2) the expansion of our unproved property positions in new shale plays.

Deferred compensation plan expense was $756,000 in the second quarter 2009 compared to $7.5 million in the same period of the prior year. Our stock price increased from $41.16 at March 31, 2009 to $41.41 at June 30, 2009. During the same period in the prior year, our stock price increased from $63.45 at March 31, 2008 to $65.54 at June 30, 2008. 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. Deferred compensation expense for the six months ended June 30, 2009 was $13.2 million compared to $28.1 million in the same period of the prior year. Our stock price increased from $34.39 at December 31, 2008 to $41.41 at June 30, 2009. During the same six month period of 2008, our stock price increased from $51.36 at December 31, 2007 to $65.54 at June 30, 2008. Our deferred compensation liability is adjusted to fair value by a charge or a credit to deferred compensation plan expense.

Income tax benefit for second quarter 2009 increased to $22.5 million, from $19.5 million in second quarter 2008, reflecting a 20% increase in loss from operations before taxes compared to the same period of 2008. Second quarter 2009 provided for a tax benefit at an effective rate of 36% compared to tax benefit at an effective rate of 38% in the same period of 2008. Current income taxes in second quarter 2009 and the six months ended June 30, 2009, are related to state income taxes. Income tax benefit for the six months ended June 30, 2009, decreased from a benefit of

$15.8 million to a benefit of $3.7 million reflecting a 75% improvement in loss from operations before taxes when compared to the same period of 2008. We expect our effective tax rate to be approximately 37% for the remainder of 2009.

Liquidity and Capital Resources

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. In a continuing effort to mitigate the effect of the deterioration in the capital markets and the steep decline in oil and gas commodity prices which began in mid 2008, we have taken additional measures during the second quarter of 2009 to improve our liquidity. In May 2009 we issued, $300.0 million of 8.0% senior subordinated notes due 2019, at a discount. We used the $285.2 million of proceeds received from the issuance of the 8.0% senior subordinated notes to repay outstanding bank debt, increasing the availability of our credit line. Also in second quarter 2009, we entered into additional commodity derivative contracts covering 25.4 Bcf for the 2010 year at weighted average floor and cap prices of $5.50 to $7.43 per mcfe to protect our cash flow. We also sold certain West Texas oil properties for proceeds of $182.0 million. We currently estimate our 2009 capital spending could be as much as $740.0 million, excluding acquisitions, which incorporates significantly reduced spending in all areas except our Marcellus Shale play.

During the six months ended June 30, 2009, our cash provided from operating activities was $268.4 million and we spent $290.8 million on capital expenditures and $107.3 million of acreage purchases. We sold certain West Texas oil properties for proceeds of $182.0 million. At June 30, 2009, we had $2.1 million in cash, total assets of $5.4 billion and a debt-to-capitalization ratio of 42.2%. Long-term debt at June 30, 2009 totaled $1.8 billion including $403.0 million of bank credit facility debt and $1.4 billion of senior subordinated notes. Available committed borrowing capacity under the bank credit facility at June 30, 2009 was $847.0 million.

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 and unused committed borrowing capacity under the bank credit facility will be adequate to satisfy near-term financial obligations and liquidity needs. However, long-term cash flows are subject to a number of variables including the level of production and prices as well as various economic conditions that have historically affected the oil and gas business. Sustained lower oil and gas prices or a reduction in production and reserves would reduce our ability to fund capital expenditures, reduce debt, meet financial obligations and remain profitable. We currently have less than 40% of our 2010 production subject to hedging agreements. We operate in an environment with numerous financial and operating risks, including, but not limited to, the inherent risks of the search for, development and production of oil and gas, the ability to buy properties and sell production at prices, which provide an attractive return and the highly competitive nature of the industry. Our ability to expand our reserve base is, in part, dependent on obtaining sufficient capital through internal cash flow, bank borrowings, asset sales or the issuance of debt or equity securities. There can be no assurance that internal cash flow and other capital sources will provide sufficient funds to maintain capital expenditures that we believe are necessary to offset inherent declines in production and proven reserves.

Our opinions concerning liquidity and our ability to avail ourselves in the future of the financing options mentioned in the above forward-looking statements are based on currently available information. If this information proves to be inaccurate, future availability of financing may be adversely affected. 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 working capital or outstanding debt and credit ratings by rating agencies.

Credit Arrangements

On June 30, 2009, 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 the banks have committed 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 is $810.0 million on July 20, 2009. Our bank group is comprised of twenty-six commercial banks, with no one bank holding more than 5.0% of the bank credit facility. We believe our large number of banks and relatively low hold levels allow for significant lending capacity should we elect to increase our $1.25 billion commitment up to the $1.5 billion borrowing base and also allow for flexibility should there be additional consolidation within the banking sector.

Our bank credit facility and our indentures governing our senior subordinated notes all contain covenants that, among other things, limit our ability to pay dividends, incur additional indebtedness, sell assets, enter into hedging contracts change the nature of our business or operations, merge or consolidate or make certain investments. In addition, we are required to maintain a ratio of debt to EBITDAX (as defined in the credit agreement) of no greater than 4.0 to 1.0 and a current ratio (as defined in the credit agreement) of no less than 1.0 to 1.0. We were in compliance with these covenants at June 30, 2009. Please see Note 8 to our consolidated financial statements for additional information.

Cash Flow

Cash flows from operations primarily are affected by production and commodity prices, net of the effects of settlements of our derivatives. Our cash flows from operating activities also are impacted by changes in working capital. We sell substantially all of our oil and gas production at the wellhead under floating market contracts. However, we generally hedge a substantial, but varying, portion of our anticipated future oil and gas production for the next 12 to 24 months. Any payments due to counterparties under our derivative contracts should ultimately be funded by higher prices received from the sale of our production. Production receipts, however, often lag payments to the counterparties. Any interim cash needs are funded by borrowing under the credit facility. As of June 30, 2009, we have entered into hedging agreements covering 61.7 Bcfe for 2009 and 25.4 Bcfe for 2010.

Net cash provided from operating activities for the six months ended June 30, 2009 was $268.4 million compared to $344.9 million in the six months ended June 30, 2008. Cash flow from operating activities for the first six months of 2009 was lower than same period of the prior year with higher production from development activity and acquisitions more than offset by lower prices. Net cash provided from continuing operations is also affected by working capital changes or the timing of cash receipts and disbursements. Changes in working capital (as reflected in the consolidated statement of cash flows) in the six months ended June 30, 2009 was a negative $26.4 million compared to a negative $92.4 million in the same period of the prior year.

Net cash used in investing for the six months ended June 30, 2009 was $215.0 million compared to $778.8 million in the same period of 2008. The first six months of 2009 included $276.0 million of additions to oil and gas properties and $107.3 million of acreage purchases offset by proceeds of $182.1 million from asset sales. Acquisitions for the first six months of 2009 include the purchase of certain Marcellus Shale leasehold acreage for $73.0 million and Barnett Shale acreage for $14.9 million. The first six months of 2008 included $407.3 million of additions to oil and gas properties and $404.9 million of acquisitions and other investments, offset by proceeds of $66.7 million from asset sales.

Net cash used in financing for the six months ended June 30, 2009 was $52.0 million compared to net cash provided from financing activities of $430.0 million in the first six months of 2008. The prior year included net proceeds from a public stock offering of $282.2 million. The six months ended June 30, 2009 includes lower borrowing on our credit facility of $227.0 million when compared to the six months ended June 30, 2008. During the first six months of 2009, total debt decreased $4.5 million.

Dividends

On June 1, 2009, the Board of Directors declared a dividend of four cents per share ($6.3 million) on our common stock, which was paid on June 30, 2009 to stockholders of record at the close of business on June 15, 2009.

Capital Requirements, Contractual Cash Obligations and Off-Balance Sheet Arrangements

We currently estimate our 2009 capital spending to be as much as $740.0 million (excluding proved property acquisitions) and based on current projections, is expected to be funded with internal cash flow and property sales. We may, from time to time during 2009, make borrowings under our credit facility but expect that for all of 2009 to require no significant incremental borrowings from ending 2008 levels. Acreage purchases during the year include $73.0 million of purchases in the Marcellus Shale and $14.9 million in the Barnett Shale which were funded with borrowings under the credit facility. In addition, in second quarter 2009, we issued 373,623 shares of stock to purchase additional Marcellus acreage. For the six months ended June 30, 2009, $299.5 million of development and exploration spending was funded with internal cash flow, borrowings under our bank credit facility and proceeds from asset sales. 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, divestiture and continued growth. We may sell assets, issue subordinated notes or other debt securities, or issue additional shares of stock to fund capital expenditures or acquisitions, extend maturities or repay debt.

Our contractual obligations include long-term debt, operating leases, drilling commitments, derivative obligations, transportation commitments and other liabilities. Since December 31, 2008, the material changes to our contractual obligations included the issuance of $300.0 million of 8% senior subordinated notes due 2019 and an increase in our transportation commitments (see table and discussion below).

We have entered into firm transportation contracts with various pipelines. Under these contracts, we are obligated to transport minimum daily gas volumes, as calculated on a monthly basis, or pay for any deficiencies at a specified reservation fee rate. As of June 30, 2009, future minimum transportation fees under our gas transportation commitments were as follows (in thousands):

2009 remaining	$ 17,774
2010	34,663
2011	34,180
2012	31,220

2013	30,349
2014	27,070
Thereafter	207,240
	$ 382,496

28

Other Contingencies

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

Hedging Oil and Gas Prices

We use commodity-based derivative contracts to manage exposure to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. These contracts consist of collars and fixed price swaps. We do not utilize complex derivatives such as swaptions, knockouts or extendable swaps. At June 30, 2009, we had open swap contracts covering 17.0 Bcf of gas at prices averaging $7.40 per mcf. We also have collars covering 61.3 Bcf of gas at weighted average floor and cap prices of $6.64 and $7.85 per mcf and 1.5 million barrels of oil at weighted average floor and cap prices of $64.01 and $76.00 per barrel. Their fair value, represented by the estimated amount that would be realized upon termination, based on a comparison of contract prices and a reference price, generally NYMEX, on June 30, 2009 was a net unrealized pre-tax gain of $169.4 million. The contracts expire monthly through December 2010. Settled transaction gains and losses for derivatives that qualify for hedge accounting are determined monthly and are included as increases or decreases in oil and gas sales in the period the hedged production is sold. In the first six months of 2009, oil and gas sales included realized hedging gains of $104.5 million compared to losses of $44.8 million in the first six months of 2008.

At June 30, 2009, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Average Hedge Price
Natural Gas			
2009	Swaps	92,351 Mmbtu/day	$7.40
2009	Collars	194,918 Mmbtu/day	$7.46-$ 8.15
2010	Collars	69,671 Mmbtu/day	$5.50-$7.43
Crude Oil			
2009	Collars	8,000 bbl/day	$64.01-$ 76.00

Some of our derivatives do not qualify for hedge accounting but are, to a degree, economic hedges of our commodity price exposure. These contracts are accounted for using the mark-to-market accounting method. Under this method, the contracts are carried at their fair value on our balance sheet under the captions Unrealized derivative gains and losses. We recognize all unrealized and realized gains and losses related to these contracts in our statement of operations caption called Derivative fair value income (loss). As of June 30, 2009, derivatives on 30.9 Bcfe no longer qualify or are not designated for hedge accounting.

In addition to the swaps and collars above, we have entered into basis swap agreements that do not qualify as hedges for hedge accounting purposes and are marked to market. The price we receive for our production can be less than NYMEX price because of adjustments for delivery location (basis), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively fix the basis adjustments. The fair value of the basis swaps was a net unrealized pre-tax loss of $4.5 million at June 30, 2009.

Interest Rates

At June 30, 2009, we had $1.8 billion of debt outstanding. Of this amount, $1.4 billion bore interest at fixed rates averaging 7.4%. Bank debt totaling $403.0 million bears interest at floating rates, which averaged 2.1% at June 30, 2009. The 30 day LIBOR rate on June 30, 2009 was 0.3%.

Debt Ratings

We receive debt credit ratings from Standard & Poor s Ratings Group, Inc. (S&P) and Moody s Investor Services, Inc. (Moody s), which are subject to regular reviews. S&P s rating for us is BB with a stable outlook. Moody s rating for us is Ba2 with a stable outlook. We believe that S&P and Moody s consider many factors in determining our ratings including: production growth opportunities, liquidity, debt levels, asset, and proved reserve mix. A reduction in our debt ratings could negatively impact our ability to obtain additional financing or the interest rate, fees and other terms associated with such additional financing.

Inflation and Changes in Prices

Our revenues, the value of our assets, our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in oil and gas prices and the costs to produce our reserves. Oil and gas prices are subject to significant fluctuations that are beyond our ability to control or predict. During second quarter 2009, we received an average of $54.62 per barrel of oil and $2.72 per mcf of gas before derivative contracts compared to $120.26 per barrel of oil and $10.09 per mcf of gas in the same period of the prior year. During the first six months of 2009, we received an average of $46.80 per barrel of oil and $3.26 per mcf of gas before derivative contracts compared to $108.06 per barrel and $8.98 per mcf in the first six months 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 continued through the first six months 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. The last half of 2008 and the first half of 2009 saw sharp declines in commodity prices and while we have realized some cost savings, operating costs have not decreased at the same rate as commodity prices. We expect to see further cost reductions in 2009 but we are uncertain how quickly costs will decline and by how much.

Accounting Standards Not Yet Adopted

In December 2008, the SEC announced that it had approved revisions to its oil and gas reporting disclosures. The new disclosure requirements include provisions that:

- Introduce a new definition of oil and gas producing activities. This new definition allows companies to include in their reserve base volumes from unconventional resources. Such unconventional resources include bitumen extracted from oil sands and oil and gas extracted from coal beds and shale formations.

- Report oil and gas reserves using an unweighted average price using the prior 12-month period, based on the closing prices on the first day of each month, rather than year-end prices. The SEC indicated that they will continue to communicate with the FASB staff to align their accounting standards with these rules. The FASB currently requires a single-day, year-end price for accounting purposes.

- Permit companies to disclose their probable and possible reserves on a voluntary basis. In the past, proved reserves were the only reserves allowed in the disclosures.

- Requires companies to provide additional disclosure regarding the aging of proved undeveloped reserves.

- Permit the use of reliable technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes.

- Replace the existing certainty test for areas beyond one offsetting drilling unit from a productive well with a reasonable certainty test.

- Require additional disclosures regarding the qualifications of the chief technical person who oversees the company s overall reserve estimation process. Additionally, disclosures regarding internal controls over reserve estimation, as well as a report addressing the independence and qualifications of its reserves preparer or auditor will be mandatory.

We will begin complying with the disclosure requirements in our annual report on Form 10-K for the year ending December 31, 2009. The new rules may not be applied to disclosures in quarterly reports prior to the first annual report in which the revised disclosures are required. We are currently in the process of evaluating the new requirements.

Table of Contents

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Financial Market Risk

The debt and equity markets have recently exhibited adverse conditions. The unprecedented volatility and upheaval in the capital markets may increase costs associated with issuing debt instruments due to increased spreads over relevant interest rate benchmarks and affect our ability to access those markets. At this point, we do not believe our liquidity has been materially affected by the recent events in the global markets and we do not expect our liquidity to be materially impacted in the near future. We will continue to monitor our liquidity and the capital markets. Additionally, we will continue to monitor events and circumstances surrounding each of our twenty-six lenders in the bank credit facility.

Market Risk

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

Commodity Price Risk

We periodically enter into derivative arrangements with respect to our oil and gas production. These arrangements are intended to reduce the impact of oil and gas price fluctuations. Certain of our derivatives are swaps where we receive a fixed price for our production and pay market prices to the counterparty. Our derivatives program also includes collars, which establish a minimum floor price and a predetermined ceiling price. Historically, we applied hedge accounting to derivatives utilized to manage price risk associated with our oil and gas production. Accordingly, we recorded change in the fair value of our swap and collar contracts under the balance sheet caption Accumulated other comprehensive income (loss) and into oil and gas sales when the forecasted sale of production occurred. Any hedge ineffectiveness associated with contracts qualifying for and designated as a cash flow hedge is reported currently each period under the income statement caption Derivative fair value income (loss). Some of our derivatives do not qualify for hedge accounting but are, to a degree, economic hedges of our commodity price exposure. These contracts are accounted for using the mark-to-market accounting method. Under this method, the contracts are carried at their fair value on our consolidated balance sheet under the captions Unrealized derivative gains and losses. We recognize all unrealized and realized gains and losses related to these contracts in our income statement under the caption Derivative fair value income (loss). 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 thirteen financial institutions, eleven of which are in our bank group. Mitsui & Co. and J. Aron & Company are the two counterparties not in our bank group. At June 30, 2009, our net derivative asset includes a payable from J. Aron & Company of $33,000 and a receivable from Mitsui & Co. for $9.9 million. None of our derivative contracts have margin requirements or collateral provisions that would require funding prior to the scheduled cash settlement date.

As of June 30, 2009, we had swaps in place covering 17.0 Bcf of gas. We also had collars covering 61.3 Bcf of gas and 1.5 million barrels of oil. These contracts expire monthly through December 2010. The fair value, represented by the estimated amount that would be realized upon immediate liquidation as of June 30, 2009, approximated a net unrealized pre-tax gain of $169.4 million.

Table of Contents

At June 30, 2009, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Average Hedge Price	Fair Market Value (in thousands)
Natural Gas				
2009	Swaps	92,351 Mmbtu/day	$7.40	$ 53,455
2009	Collars	194,918 Mmbtu/day	$7.46-$8.15	$ 112,325
2010	Collars	69,671 Mmbtu/day	$5.50-$7.43	$ 6,160
Crude Oil				
2009	Collars	8,000 bbl/day	$64.01-$76.00	$ (2,509)

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 swaps detailed above, we have entered into basis swap agreements, which do not qualify for hedge accounting and are marked to market. The price we receive for our gas production can be less than the NYMEX price because of adjustments for delivery location (basis), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively fix the basis adjustments. The fair value of the basis swaps was a net realized pre-tax loss of $4.5 million at June 30, 2009.

The following table shows the fair value of our swaps and collars and the hypothetical change in the fair value that would result from a 10% change in commodity prices at June 30, 2009. The hypothetical change in fair value would be a gain or loss depending on whether prices increase or decrease (in thousands):

	Fair Value	Hypothetical Change in Fair Value
Swaps	$ 53,455	$ 7,200
Collars	$115,976	$ 31,000

Interest rate risk. At June 30, 2009, we had $1.8 billion of debt outstanding. Of this amount, $1.4 billion bore interest at fixed rates averaging 7.4%. Senior bank debt totaling $403.0 million bore interest at floating rates averaging 2.1%. A 1% increase or decrease in short-term interest rates would affect interest expense by approximately $4.0 million per year.

Item 4. CONTROLS AND PROCEDURES

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 or the Exchange Act). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective in timely alerting us to material information required to be included in this report. There were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Table of Contents

PART II Other Information

Item 1A. RISK FACTORS

There has been no material change to our risk factors set forth in Part I, Item 1A, Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2008 except as set forth below.

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

The United States Congress is currently considering legislation to amend the Safe Drinking Water Act to eliminate an existing exemption for hydraulic fracturing activities. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formation to stimulate natural gas production. We find that the use of hydraulic fracturing is necessary to produce commercial quantities of natural gas and oil from many reservoirs, especially shale formations such as the Marcellus Shale. If adopted, this legislation could establish an additional level of regulation and permitting at the federal level. This additional regulation and permitting could lead to significant operational delays or increased operating costs and could result in additional burdens that could increase our costs of compliance and doing business and make it more difficult to perform hydraulic fracturing.

Item 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

On May 20, 2009, we held our annual meeting of stockholders to elect a Board of nine directors each for a one-year term, vote on proposals to amend the 2005 Equity Based Compensation Plan including an increase to the number of shares to be issued and to ratify the appointment of Ernst & Young LLP as our registered public accounting firm for 2009. At the meeting, Charles L. Blackburn, Anthony V. Dub, V. Richard Eales, Allen Finkelson, James M. Funk, Jonathan S. Linker, Kevin S. McCarthy, John H. Pinkerton and Jeffrey L. Ventura were re-elected as Directors. John H. Pinkerton was elected Chairman of the Board and V. Richard Eales was appointed Lead Director by the Board of Directors.

The following is a summary of the votes cast at the annual meeting:

Results of Voting	**Votes For**	**Withheld**
1. Election of Directors		
Charles L. Blackburn	138,991,426	28,590
Anthony V. Dub	138,356,572	38,370
V. Richard Eales	139,653,452	41,237
Allen Finkelson	137,578,502	39,390
James M. Funk	139,713,410	28,257
Jonathan S. Linker	139,436,483	40,176
Kevin S. McCarthy	137,818,693	29,110
John H. Pinkerton	137,081,965	37,387
Jeffrey L. Ventura	138,445,086	28,990

	Votes For	**Against**	**Abstentions**	**Broker Non-Votes**
2. Amendments to our 2005 Equity-Based Plan	104,478,929	19,140,168	55,214	16,602,547
3. Appointment of Ernst & Young LLP	139,977,500	227,107	72,251	

Item 6. Exhibits
(a) EXHIBITS

Exhibit Number	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 First 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, 2007)
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 February 17, 2009)
10.1	Range Resources Corporation Amended and Restated 2005 Equity Based Compensation Plan (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on June 4, 2009)
31.1*	Certification by the Chairman and Chief Executive Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification by the Chief Financial Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Certification by the Chairman and Chief Executive Officer of Range Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification by the Chief Financial Officer of Range Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101*	XBRL documents

* filed herewith

** furnished herewith

Table of Contents

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.

RANGE RESOURCES CORPORATION

By: /s/ ROGER S. MANNY
Roger S. Manny
Executive Vice President and Chief Financial Officer
(Principal Financial Officer and duly authorized to sign this report on behalf of the Registrant)

July 22, 2009

II-1

Table of Contents

Exhibit index

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