RANGE RESOURCES CORP
Form 10-Q
October 26, 2011

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

FORM 10-Q

(Mark one)

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

For the quarterly period ended September 30, 2011

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 o No o

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

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

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

161,255,791 Common Shares were outstanding on October 21, 2011.

RANGE RESOURCES CORPORATION
FORM 10-Q
Quarter Ended September 30, 2011

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

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PART I FINANCIAL INFORMATION
ITEM 1. Financial Statements

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

	September 30, 2011 (Unaudited)	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 51,884	$ 2,848
Accounts receivable, less allowance for doubtful accounts of $4,238 and $5,001	86,172	76,683
Unrealized derivative gain	136,488	123,255
Assets of discontinued operations	2,626	876,304
Inventory and other	13,600	21,352
Total current assets	290,770	1,100,442
Unrealized derivative gain	47,121	
Equity method investments	136,244	155,105
Natural gas and oil properties, successful efforts method	6,420,030	5,390,391
Accumulated depletion and depreciation	(1,573,195)	(1,306,378)
	4,846,835	4,084,013
Transportation and field assets	121,979	134,980
Accumulated depreciation and amortization	(67,715)	(60,931)
	54,264	74,049
Other assets	101,244	84,977
Total assets	$ 5,476,478	$ 5,498,586
Liabilities		
Current liabilities:		
Accounts payable	$ 299,097	$ 289,109
Asset retirement obligations	4,020	4,020
Accrued liabilities	59,348	60,082
Deferred tax liability	9,593	11,848
Accrued interest	33,805	32,189
Unrealized derivative loss		352
Liabilities of discontinued operations	1,064	32,962
Total current liabilities	406,927	430,562

Bank debt				274,000
Subordinated notes		1,787,678		1,686,536
Deferred tax liability		714,677		672,041
Unrealized derivative loss				13,412
Deferred compensation liability		165,810		134,488
Asset retirement obligations and other liabilities		77,633		59,885
Liabilities of discontinued operations				3,901
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, 161,133,525 issued at September 30, 2011 and 160,113,608 issued at December 31, 2010		1,611		1,601
Common stock held in treasury, 174,715 shares at September 30, 2011 and 204,556 shares at December 31, 2010		(6,456)		(7,512)
Additional paid-in capital		1,858,980		1,820,503
Retained earnings		383,409		341,699
Accumulated other comprehensive income		86,209		67,470
Total stockholders equity		2,323,753		2,223,761
Total liabilities and stockholders equity	$	5,476,478	$	5,498,586

See the accompanying notes.

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RANGE RESOURCES CORPORATION

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

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Revenues and other income				
Natural gas, NGL and oil sales	$ 271,799	$ 187,757	$ 755,367	$ 548,583
Transportation and gathering	816	(1,640)	88	1,104
Derivative fair value income	65,762	9,981	77,967	58,860
Gain (loss) on the sale of assets	203	67	(1,280)	78,156
Other	(375)	(1,010)	268	(1,948)
Total revenues and other income	338,205	195,155	832,410	684,755
Costs and expenses				
Direct operating	29,828	25,535	87,054	68,542
Production and ad valorem taxes	7,317	6,903	21,746	19,108
Exploration	17,606	15,225	56,385	43,784
Abandonment and impairment of unproved properties	16,627	14,435	52,064	30,713
General and administrative	35,907	36,523	108,986	100,529
Termination costs				7,938
Deferred compensation plan	8,717	(5,347)	33,569	(25,194)
Interest expense	34,181	23,363	90,343	65,565
Loss on early extinguishment of debt	(4)	5,351	18,576	5,351
Depletion, depreciation and amortization	93,619	69,730	244,129	202,350
Impairment of proved properties	38,681		38,681	6,505
Total costs and expenses	282,479	191,718	751,533	525,191
Income from continuing operations before income taxes	55,726	3,437	80,877	159,564
Income tax expense (benefit)				
Current	(7)	(10)	1	(10)
Deferred	22,547	794	35,345	61,569
Total income tax expense	22,540	784	35,346	61,559
Income from continuing operations	33,186	2,653	45,531	98,005
Discontinued operations, net of taxes	1,569	(10,821)	15,484	(19,542)
Net income (loss)	$ 34,755	$ (8,168)	$ 61,015	$ 78,463

Income (loss) per common share				
Basic-income from continuing operations	$ 0.21	$ 0.02	$ 0.28	$ 0.61
-discontinued operations	0.01	(0.07)	0.10	(0.12)
-net income (loss)	$ 0.22	$ (0.05)	$ 0.38	$ 0.49
Diluted-income from continuing operations	$ 0.20	$ 0.02	$ 0.28	$ 0.61
-discontinued operations	0.01	(0.07)	0.10	(0.12)
-net income (loss)	$ 0.21	$ (0.05)	$ 0.38	$ 0.49
Dividends per common share	$ 0.04	$ 0.04	$ 0.12	$ 0.12
Weighted average common shares outstanding				
Basic	158,154	157,109	157,901	156,777
Diluted	159,322	158,184	158,939	158,493

See the accompanying notes.

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RANGE RESOURCES CORPORATION

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	**2010**	**2011**	**2010**
Net income (loss)	$ 34,755	$ (8,168)	$ 61,015	$ 78,463
Other comprehensive (loss) income:				
Realized gain on hedge derivative contract settlements reclassified into earnings from other comprehensive income, net of taxes	(16,724)	(9,602)	(55,791)	(21,726)
Change in unrealized deferred hedging gains, net of taxes	56,993	66,968	74,530	115,293
Total comprehensive income	$ 75,024	$ 49,198	$ 79,754	$ 172,030

See the accompanying notes.

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RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited, in thousands)

	Nine Months Ended September 30,	
	2011	**2010**
Operating activities		
Net income	$ 61,015	$ 78,463
Adjustments to reconcile net cash provided from operating activities:		
(Gain) loss from discontinued operations	(15,484)	19,542
Loss from equity method investments, net of distributions	24,899	1,830
Deferred income tax expense	35,345	61,569
Depletion, depreciation, amortization and proved property impairment	282,810	208,855
Exploration dry hole costs	2,515	1,661
Mark-to-market gain on gas and oil derivatives not designated as hedges	(67,093)	(23,885)
Abandonment and impairment of unproved properties	52,064	30,713
Unrealized derivative gain	(2,531)	(2,400)
Allowance for bad debts	446	
Deferred and stock-based compensation	66,759	10,313
Amortization of deferred financing costs, loss on extinguishment of debt and other	23,753	8,892
Loss (gain) on sale of assets	1,280	(78,156)
Changes in working capital:		
Accounts receivable	(29,579)	(1,735)
Inventory and other	875	(2,407)
Accounts payable	(19,705)	12,365
Accrued liabilities and other	(24,285)	4,142
Net cash provided from continuing operations	393,084	329,762
Net cash provided from discontinued operations	20,710	69,106
Net cash provided from operating activities	413,794	398,868
Investing activities		
Additions to oil and gas properties	(855,354)	(540,532)
Additions to field service assets	(5,914)	(12,284)
Acreage and proved property purchases	(151,118)	(249,731)
Other assets		(45)
Proceeds from disposal of assets	66,213	327,454
Purchase of marketable securities held by the deferred compensation plan	(15,626)	(16,399)
Proceeds from the sales of marketable securities held by the deferred compensation plan	8,451	14,943
Net cash used in investing activities from continuing operations	(953,348)	(476,594)
Investing activities of discontinued operations	844,894	(49,221)

Net cash used in investing activities	(108,454)	(525,815)
Financing activities		
Borrowing on credit facilities	490,826	784,000
Repayment on credit facilities	(764,826)	(943,000)
Dividends paid	(19,305)	(19,170)
Issuance of common stock	585	5,904
Issuance of subordinated notes	500,000	500,000
Repayment of subordinated notes	(413,698)	(202,458)
Debt issuance costs	(22,003)	(9,435)
Change in cash overdrafts	(39,761)	7,609
Proceeds from the sales of common stock held by the deferred compensation plan	11,878	4,808
Net cash (used in) provided from financing activities	(256,304)	128,258
Increase in cash and equivalents	49,036	1,311
Cash and cash equivalents at beginning of period	2,848	767
Cash and cash equivalents at end of period	$ 51,884	$ 2,078

See the accompanying notes.

RANGE RESOURCES CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

(1) ORGANIZATION AND NATURE OF BUSINESS

We are a Fort Worth, Texas-based independent natural gas and oil company engaged in the exploration, development and acquisition of natural gas and oil properties, mostly in the Appalachia and the Southwest regions of the United States. Our objective is to build stockholder value through consistent growth in reserves and production on a cost-efficient basis. Range Resources Corporation is a Delaware corporation with our common stock listed and traded on the New York Stock Exchange under the symbol RRC.

(2) BASIS OF PRESENTATION

Presentation

These interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in our current report on Form 8-K filed on May 6, 2011, as amended by the Form 8-K/A filed on May 10, 2011. The results of operations for the quarter and the nine months ended September 30, 2011 are not necessarily indicative of the results to be expected for the full year. 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 (U.S. GAAP) for complete financial statements. The third quarter 2011 includes an adjustment of $4.2 million to record depletion related to our Oklahoma properties related to prior periods. This adjustment was immaterial to prior periods.

Discontinued Operations

In February 2011, we entered into an agreement to sell substantially all of our Barnett Shale assets. In April 2011, we completed the sale of most of these assets and closed the remainder of the sale in August 2011. We have classified the assets and liabilities of these assets as discontinued operations in the accompanying consolidated balance sheets along with the historic results of these operations as discontinued operations, net of tax, in the accompanying consolidated statements of operations. See also Notes 4 and 5 for more information regarding the sale of our Barnett Shale assets. Unless otherwise indicated, the information in these notes to the consolidated financial statements relate to our continuing operations.

(3) NEW ACCOUNTING STANDARDS

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRS). This pronouncement was issued to provide a consistent definition of fair value and ensure that the fair value measurement and disclosure requirements are similar between U.S. GAAP and IFRS. ASU 2011-04 changes certain fair value measurement principles and enhances the disclosure requirements, particularly for Level 3 fair value measurements. This pronouncement is effective for reporting periods beginning on or after December 15, 2011, with early adoption prohibited. The new guidance will require prospective application. The adoption of ASU 2011-04 is not expected to have a material effect on our consolidated financial statements, but may require additional disclosures.

In June 2011, the FASB issued ASU No. 2011-05, Presentation of Comprehensive Income, which was issued to enhance comparability between entities that report under U.S. GAAP and IFRS, and to provide a more consistent method of presenting non-owner transactions that affect an entity s equity. ASU 2011-05 eliminates the option to report other comprehensive income and its components in the statement of changes in stockholders equity and requires an entity to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement or in two separate but consecutive statements. This pronouncement is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. Early adoption of the new guidance is permitted and full retrospective application is required. We adopted this new requirement in third quarter 2011 and since ASU 2011-05 only amended presentation requirements, it did not have a material effect on our consolidated financial statements.

(4) DISPOSITIONS

2011 Asset Sales

In February 2011, we entered into an agreement to sell substantially all of our Barnett Shale properties located in North Central Texas (Dallas, Denton, Ellis, Hill, Hood, Johnson, Parker, Tarrant and Wise Counties), which also included the assumption of certain derivative contracts by the buyer and was subject to normal post-closing adjustments. We closed

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substantially all of this sale in April 2011 and closed the remainder in August 2011. The gross cash proceeds were approximately $889.3 million, including the derivative contracts assumed. The agreements had a February 1, 2011 effective date and consequently operating net revenues after February 1, 2011 were a downward adjustment to the sales price. We recorded a pretax gain of $4.9 million in discontinued operations related to this sale. In the accompanying December 31, 2010 balance sheet, we have classified these assets and liabilities as discontinued operations. As indicated in Notes 2 and 5, the historic results of our Barnett Shale operations are presented as discontinued operations.

As part of the sale of our Barnett Shale properties, certain derivative contracts were assumed by the buyer. This resulted in a loss of $1.7 million in second quarter 2011 which is included in continuing operations. As required by cash flow hedge accounting rules, a $9.4 million pretax gain related to these hedges is included in accumulated other comprehensive income at September 30, 2011 and will be recognized in earnings during the remainder of 2011 as the hedged production occurs. The hedges assumed by the buyer as part of the sale were not designated to our Barnett Shale production and were sold to balance our volumes hedged.

In third quarter 2011, we sold various producing properties located in East Texas for proceeds of $11.0 million. We recognized an impairment of $31.2 million related to the sale of these properties. For additional information on this impairment, see Note 13. Also in third quarter 2011, we sold producing properties in Pennsylvania for proceeds of $6.0 million, with no gain or loss recognized, as the sale did not materially impact the depletion rate of the remaining properties in the amortization base.

2010 Asset Sales

In February 2010, we entered into an agreement to sell our tight gas sand properties in Ohio. We closed approximately 90% of the sale in March 2010 and closed the remainder in June 2010. Total proceeds were approximately $323.0 million and we recorded a gain of $77.4 million in continuing operations. The agreement had an effective date of January 1, 2010, and consequently operating net revenues after January 1, 2010 were a downward adjustment to the sales price. The proceeds we received were placed in a like-kind exchange account and in June 2010, we used a portion of the proceeds to purchase proved and unproved natural gas properties in Virginia. In September 2010, the like-kind exchange account was closed and the balance of these proceeds (approximately $135.0 million) was used to repay amounts outstanding under our bank credit facility.

(5) DISCONTINUED OPERATIONS

The following table presents the components of our Barnett Shale operations as discontinued operations for the three months and the nine months ended September 30, 2011 and 2010 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	**2010**	**2011**	**2010**
Revenues and other income				
Natural gas, NGL and oil sales	$ 723	$ 31,803	$ 53,757	$ 114,521
Transportation and gathering		6	6	29
Gain on the sale of assets	1,032		4,852	955
Other		(3)	4	(3)
Total revenues and other income	1,755	31,806	58,619	115,502
Costs and expenses				
Direct operating	(611)	8,752	9,835	26,560
Production and ad valorem taxes	(44)	1,970	1,206	5,925
Exploration		11	37	560
Abandonment and impairment of unproved properties		6,099		15,725
Interest expense		10,443	14,791	29,307

Depletion, depreciation and amortization		22,038	8,894	69,041
Total costs and expenses	(655)	49,313	34,763	147,118
Income (loss) from discontinued operations before income taxes	2,410	(17,507)	23,856	(31,616)
Income tax expense (benefit)				
Current				
Deferred	841	(6,686)	8,372	(12,074)
Total income tax expense (benefit)	841	(6,686)	8,372	(12,074)
Net income (loss) from discontinued operations	$ 1,569	$ (10,821)	$ 15,484	$ (19,542)

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The carrying values of our Barnett Shale operations are included in discontinued operations in the accompanying consolidated balance sheets which are comprised of the following (in thousands):

	September 30, 2011		December 31, 2010	
Composition of assets of discontinued operations:				
Natural gas and oil properties, net	$		$	838,044
Transportation and field assets, net				684
Accounts receivable		2,626		29,300
Unrealized derivative gain				8,195
Inventory and other				81
Total assets of discontinued operations	$	2,626	$	876,304
Composition of liabilities of discontinued operations:				
Account payable	$	1,064	$	23,366
Accrued liabilities				9,596
Total current liabilities of discontinued operations	$	1,064	$	32,962
Asset retirement obligations	$		$	1,980
Other liabilities				1,921
Total long-term liabilities of discontinued operations	$		$	3,901

(6) INCOME TAXES

Income tax expense from continuing operations was as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Income tax expense	$ 22,540	$ 784	$ 35,346	$ 61,559
Effective tax rate	40.4%	22.8%	43.7%	38.6%

We compute our quarterly taxes under the effective tax rate method based on applying an anticipated annual effective rate to our year-to-date income, except for discrete items. Income taxes for discrete items are computed and recorded in the period that the specific transaction occurs. For the three months and the nine months ended September 30, 2011 and 2010, our overall effective tax rate on pre-tax income from continuing operations was different than the statutory rate of 35% due primarily to state income taxes, valuation allowances and other permanent differences.

(7) INCOME (LOSS) PER COMMON SHARE

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

	Three Months Ended September 30, 2011			Three Months Ended September 30, 2010		
	Continuing Operations	Discontinued Operations	Total	Continuing Operations	Discontinued Operations	Total
Income (loss) as reported	$ 33,186	$ 1,569	$ 34,755	$ 2,653	$ (10,821)	$ (8,168)
Participating basic earnings[a]	(585)	(28)	(613)	(117)		(117)
Basic income (loss) attributed to common stockholders	32,601	1,541	34,142	2,536	(10,821)	(8,285)
Reallocation of participating earnings[a]	3		3			
Diluted income (loss) attributed to common stockholders	$ 32,604	$ 1,541	$ 34,145	$ 2,536	$ (10,821)	$ (8,285)
Income (loss) per common share:						
Basic	$ 0.21	$ 0.01	$ 0.22	$ 0.02	$ (0.07)	$ (0.05)
Diluted	$ 0.20	$ 0.01	$ 0.21	$ 0.02	$ (0.07)	$ (0.05)

	Nine Months Ended September 30, 2011			Nine Months Ended September 30, 2010		
	Continuing Operations	Discontinued Operations	Total	Continuing Operations	Discontinued Operations	Total
Income (loss) as reported	$ 45,531	$ 15,484	$ 61,015	$ 98,005	$ (19,542)	$ 78,463

Participating basic earnings[a]	(818)	(278)	(1,096)	(1,723)	344	(1,379)
Basic income (loss) attributed to common stockholders	44,713	15,206	59,919	96,282	(19,198)	77,084
Reallocation of participating earnings[a]	3	2	5	15	(4)	11
Diluted income (loss) attributed to common stockholders	$ 44,716	$ 15,208	$ 59,924	$ 96,297	$ (19,202)	$ 77,095
Income (loss) per common share:						
Basic	$ 0.28	$ 0.10	$ 0.38	$ 0.61	$ (0.12)	$ 0.49
Diluted	$ 0.28	$ 0.10	$ 0.38	$ 0.61	$ (0.12)	$ 0.49

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

		Three Months Ended September 30,		Nine Months Ended September 30,	
		2011	2010	2011	2010
Denominator:					
Weighted average common shares outstanding	basic	158,154	157,109	157,901	156,777
Effect of dilutive securities:					
Employee stock options and SARs		1,168	1,075	1,038	1,716
Weighted average common shares outstanding	diluted	159,322	158,184	158,939	158,493

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The weighted average common shares basic for the three months ended September 30, 2011 excludes 2.9 million shares of restricted stock compared to 2.9 million shares excluded at September 30, 2010, which are held in our deferred compensation plans (although all restricted stock is issued and outstanding upon grant). Weighted average common shares-basic for the nine months ended September 30, 2011 exclude 2.9 million shares of restricted stock compared to 2.8 million for the nine months ended September 30, 2010. SARs of 347,000 for the three months ended September 30, 2011 and 3.5 million for the three months ended September 30, 2010 were outstanding but not included in the computations of diluted income from continuing operations per share because the grant prices of the SARs were greater than the average market price of the common shares. SARs of 855,000 for the nine months ended September 30, 2011 and 2.0 million for the nine months ended September 30, 2010 were outstanding but not included in the computations of diluted income from continuing operations per share because the grant prices of the SARs were greater than the average market price of the common shares.

(8) SUSPENDED EXPLORATORY WELL COSTS

The following table reflects the changes in capitalized exploratory well costs for the nine months ended September 30, 2011 and the year ended December 31, 2010 (in thousands):

	September 30, 2011	December 31, 2010
Beginning balance at January 1	$ 23,908	$ 19,052
Additions to capitalized exploratory well costs pending the determination of proved reserves	71,779	28,897
Reclassifications based on determination of proved reserves	(12,488)	(24,041)
Capitalized exploratory well costs charged to expense		
Balance at end of period	83,199	23,908
Less exploratory well costs that have been capitalized for a period of one year or less	(68,171)	(13,181)
Capitalized exploratory well costs that have been capitalized for a period greater than one year	$ 15,028	$ 10,727
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	5	4

At September 30, 2011, of the $15.0 million of capitalized exploratory well costs that have been capitalized for more than one year, all of the wells are Marcellus Shale wells and are waiting on the completion of pipelines. The following provides an aging of capitalized exploratory well costs that have been suspended for more than one year as of September 30, 2011 (in thousands):

	Total	2011	2010	2009	2008
Capitalized exploratory well costs that have been capitalized for more than one year	$ 15,028	$ 494	$ 10,127	$ 2,884	$ 1,523

(9) INDEBTEDNESS

We had the following debt outstanding as of the dates shown below (in thousands). No interest expense was capitalized during the three months and the nine months ended September 30, 2011 and 2010.

December 31,

	September 30, 2011	2010
Bank debt	$	$ 274,000
Subordinated debt:		
6.375% Senior Subordinated Notes due 2015		150,000
7.5% Senior Subordinated Notes due 2016, net of discount		249,683
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	287,678	286,853
6.75% Senior Subordinated Notes due 2020	500,000	500,000
5.75% Senior Subordinated Notes due 2021	500,000	
Total debt	$ 1,787,678	$ 1,960,536

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Bank Debt

In February 2011, 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 borrowing base was set without our Barnett Shale assets. The bank credit facility provides for an initial commitment equal to the lesser of the facility amount or the borrowing base. On September 30, 2011, the borrowing base was $2.0 billion and our facility amount was $1.5 billion. The bank credit facility provides for a borrowing base subject to redeterminations semi-annually and for event-driven unscheduled redeterminations. As part of our semi-annual bank review completed on October 12, 2011, our borrowing base was reaffirmed at $2.0 billion and our facility amount was also reaffirmed at $1.5 billion. Our current bank group is comprised of twenty-six commercial banks with no one bank holding more than 7% of the total facility. The facility amount may be increased up to the borrowing base amount with twenty days notice, subject to payment of a mutually acceptable commitment fee to those banks agreeing to participate in the facility amount increase. At September 30, 2011, we had no outstanding balances under our bank credit facility and we had $22.2 million of undrawn letters of credit leaving approximately $1.5 billion of borrowing capacity available under the facility amount. The facility matures in February 2016. Borrowing under the bank credit facility can either be the Alternate Base Rate (as defined) plus a spread ranging from 0.50% to 1.50% or LIBOR borrowings at the Adjusted LIBO Rate (as defined) plus a spread ranging from 1.50% to 2.50%. The applicable spread is dependent upon borrowings relative to the borrowing base. We may elect, from time to time, to convert all or any part of our LIBOR loans to base rate loans or to convert all or any part of the base rate loans to LIBOR loans. The weighted average interest rate on the bank credit facility was 2.3% for the three months ended September 30, 2010. The weighted average interest rate on the bank credit facility was 2.2% for the nine months ended September 30, 2011 compared to 2.2% for the nine months ended September 30, 2010. A commitment fee is paid on the undrawn balance based on an annual rate of between 0.375% and 0.50%. At September 30, 2011, the commitment fee was 0.375%. At October 21, 2011, the balance on our bank credit facility was $77.0 million and our interest rate (including applicable margins) was 3.75%.

Senior Subordinated Notes

In May 2011, we issued $500.0 million aggregate principal amount of 5.75% senior subordinated notes due 2021 (5.75% Notes) for net proceeds after underwriting discounts and commissions of $491.3 million. The 5.75% Notes were issued at par. Interest on the 5.75% Notes is payable semi-annually in June and December and is guaranteed by all of our current subsidiaries. We may redeem the 5.75% Notes, in whole or in part, at any time on or after June 1, 2016, at redemption prices of 102.875% of the principal amount as of June 1, 2016, declining to 100.0% on June 1, 2019 and thereafter. Before June 2014, we may redeem up to 35% of the original aggregate principal amount of the 5.75% Notes at a redemption price equal to 105.75% of the principal amount thereof, plus accrued and unpaid interest, if any, with the proceeds of certain equity offerings, provided that 65% of the aggregate principal amount of 5.75% Notes remains 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. On closing, we used $112.9 million of the proceeds to purchase our 6.375% senior subordinated notes due 2015 and $207.1 million of the proceeds to purchase our 7.5% senior subordinated notes due 2016 as part of the tender offer and redemption described below.

On May 11, 2011, we commenced cash tender offers to purchase the entire outstanding $150.0 million principal amount of our 6.375% senior subordinated notes due 2015 and $250.0 million principal amount of our 7.5% senior subordinated notes due 2016. On May 25, 2011, after the expiration of the tender offers, we accepted for purchase $108.9 million in principal of the 2015 notes at 102.375% of par and $198.8 million in principal of the 2016 notes for 104.00% of par. We subsequently called the remaining 2015 and 2016 notes, redeeming all of the remaining outstanding 2015 notes ($41.1 million) at 102.125% of par on June 24, 2011 and redeeming all of the remaining outstanding 2016 notes ($51.2 million) at 103.75% of par on June 24, 2011. During second quarter 2011, we recognized an $18.6 million loss on extinguishment of debt, including transaction call premium cost as well as expensing of deferred financing cost on repurchased debt.

Debt Covenants

Our bank credit facility contains negative covenants that limit our ability, among other things, to pay cash dividends, incur additional indebtedness, sell assets, enter into certain hedging contracts, change the nature of our business or operations, merge, consolidate, or make investments. In addition, we are required to maintain a ratio of debt to EBITDAX (as defined in the credit agreement) of no greater than 4.25 to 1.0 and a current ratio (as defined in the credit agreement) of no less than 1.0 to 1.0. We were in compliance with our covenants under the bank credit facility at September 30, 2011.

The indentures governing our senior subordinated notes contain various restrictive covenants that are substantially identical to each other and may limit our ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, enter into transactions with affiliates or change the nature of our business. At September 30, 2011, we were in compliance with these covenants.

(10) ASSET RETIREMENT OBLIGATIONS

Our asset retirement obligations primarily represent the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives. Significant inputs used in determining such obligations include estimates of plugging and abandonment costs, estimated future inflation rates and well life. A reconciliation of our liability for plugging, abandonment and remediation costs for the nine months ended September 30, 2011 is as follows (in thousands):

	Nine Months Ended September 30, 2011
Beginning of period continuing operations	$ 60,693
Liabilities incurred	2,299
Liabilities settled	(3,109)
Accretion expense continuing operations	3,980
Change in estimate	11,270
End of period continuing operations	$ 75,133

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

(11) 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. We currently have no preferred stock issued or outstanding. The following is a summary of changes in the number of common shares outstanding since the beginning of 2010:

	Nine Months Ended September 30, 2011	Year Ended December 31, 2010
Beginning balance	159,909,052	158,118,937
Stock options/SARs exercised	693,326	991,988
Restricted stock grants	326,591	405,127
Treasury shares issued	29,841	12,771
Shares issued for acreage purchases		380,229
Ending balance	160,958,810	159,909,052

Treasury Stock

The Board of Directors has approved up to $10.0 million of repurchases of common stock based on market conditions and opportunities and on September 30, 2011, we have $6.8 million remaining under this authorization.

(12) DERIVATIVE ACTIVITIES

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. We do not utilize complex derivatives such as swaptions, knockouts or extendable swaps. We typically utilize commodity swap, collar or call option contracts to (1) reduce the effect of price volatility of the commodities we produce and sell and (2) support our annual capital budget and expenditure plans. Historically, our derivative activities have consisted of collars and fixed price swaps. At September 30, 2011, we had open swap contracts covering 25.6 Bcf of natural gas at prices averaging $5.00 per mcf and 2.5 million barrels of NGLs (the C5 component of NGLs) at prices averaging $103.00 per barrel. At September 30, 2011, we had collars covering 159.8 Bcf of natural gas at weighted average floor and cap prices of $5.24 to $5.87 per mcf and 0.7 million barrels of oil at weighted average floor and cap prices of $70.00 to $80.00 per barrel. At September 30, 2011, we also had sold call options for 2.2 million barrels of oil at a weighted average price of $83.86. At the time of settlement of these monthly call options, if the market price exceeds the fixed price of the call option, we will pay the counterparty such excess and if the market settles below the fixed price of the call option, no payment is due from either party. Beginning with first quarter 2011, we have entered into NGL derivative swap contracts for the natural gasoline (or C5) component of natural gas liquids. The fair value of our commodity derivatives, represented by the estimated amount that would be realized upon termination, based on a comparison of the contract prices and a reference price, generally New York Mercantile Exchange (NYMEX), on September 30, 2011, was a net unrealized pre-tax gain of $183.6 million. These contracts expire monthly through December 2013.

The following table sets forth our derivative volumes and average hedge prices as of September 30, 2011:

Period	Contract Type	Volume Hedged	Average Hedge Price
Natural Gas			
2012	Swaps	70,000 Mmbtu/day	$ 5.00
2011	Collars	348,200 Mmbtu/day	$ 5.33 - $6.18
2012	Collars	189,641 Mmbtu/day	$ 5.32 - $5.91
2013	Collars	160,000 Mmbtu/day	$ 5.09 - $5.65
Crude Oil			
2012	Collars	2,000 bbls/day	$ 70.00 - $80.00
2011	Call options	5,500 bbls/day	$ 80.00
2012	Call options	4,700 bbls/day	$ 85.00
NGLs (Natural gasoline)			
2011	Swaps	7,000 bbls/day	$ 104.17
2012	Swaps	5,000 bbls/day	$ 102.59

Every derivative instrument is recorded on the accompanying balance sheets as either an asset or a liability measured at its fair value. Fair value is generally determined based on the difference between the fixed contract price and the underlying market price at the determination date. Changes in the fair value of derivatives that qualify for hedge accounting are recorded as a component of accumulated other comprehensive income (AOCI) in the stockholders equity section of the accompanying consolidated balance sheets, which is later transferred to natural gas, NGL and oil sales when the underlying physical transaction occurs and the hedging contract is settled. Amounts included in AOCI at September 30, 2011 and December 31, 2010 relate solely to our commodity derivative activities. As of September 30, 2011, an unrealized pre-tax derivative gain of $137.9 million was recorded in AOCI. This gain is expected to be reclassified into earnings as a $37.9 million gain in 2011, a $73.8 million gain in 2012 and a $26.2 million gain in 2013. The actual reclassification to earnings will be based on market prices at the contract settlement date.

For those derivative instruments that qualify for hedge accounting, settled transaction gains and losses are determined monthly, and are included as increases or decreases to natural gas, NGL and oil sales in the period the hedged production is sold. Natural gas, NGL and oil sales include $26.8 million of gains in the three months ended September 30, 2011 compared to gains of $15.6 million in the same period of 2010 related to settled hedging transactions. Natural gas, NGL and oil sales include $80.7 million of gains in the nine months ended September 30, 2011 compared to gains of $35.2 million in the same period of 2010 related to settled hedges. Any ineffectiveness associated with these hedge derivatives is included in derivative fair value income in the accompanying consolidated statements of operations. The ineffective portion is calculated as the difference between the change in fair value of the derivative and the estimated change in future cash flows from the item hedged. The three months ended September 30, 2011 includes ineffective losses (unrealized and realized) of $1.9 million compared to gains of $2.4 million in the same period of 2010. The nine months ended September 30, 2011 includes ineffective gains (unrealized and realized) of $7.1 million compared to losses of $2.0 million in the same period of 2010. As part of the sale of our Barnett Shale properties, certain derivative contracts were assumed by the buyer. This resulted in a loss of $1.7 million in second quarter 2011. As required by cash flow hedge accounting, a $9.4 million pretax gain related to these hedges is included in accumulated other comprehensive income at September 30, 2011 and will be recognized in earnings during the remainder of 2011 as the hedged production occurs. The hedges assumed as part of the sale were not designated to our Barnett Shale production and were sold to balance our volumes hedged.

Through September 30, 2011, we have elected to designate our commodity derivative instruments that qualify for hedge accounting as cash flow hedges. To designate a derivative as a cash flow hedge, we document at the hedge s inception our assessment that the derivative will be highly effective in offsetting expected changes in cash flows from the item hedged. This assessment, which is updated at least quarterly, is generally based on the most recent relevant historical correlation between the derivative and the item hedged. The ineffective portion of the hedge is calculated as the difference between the change in fair value of the derivative and the estimated change in cash flows from the item hedged. If, during the derivative s term, we determine the hedge is no longer highly effective, hedge accounting is prospectively discontinued and any remaining unrealized gains or losses, based on the effective portion of the derivative at that date, are reclassified to earnings as natural gas, NGL and oil sales when the underlying transaction occurs. If it is determined that the designated hedge

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transaction is not probable to occur, any unrealized gains or losses are recognized immediately in derivative fair value income (loss) in the accompanying consolidated statements of operations. During the first nine months of 2011 and 2010, there were no gains or losses recorded due to the discontinuance of hedge accounting treatment for these derivatives.

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

Derivative Fair Value Income

The following table presents information about the components of derivative fair value income in the three and nine months ended September 30, 2011 and 2010 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Hedge ineffectiveness realized	$ 2,036	$	$ 4,558	$ (352)
unrealized	(3,971)	2,389	2,531	2,400
Change in fair value of derivatives that do not qualify for hedge accounting[a]	58,990	(18,284)	67,093	23,885
Realized gain on settlements gas[a] [b]	5,334	10,179	8,424	17,230
Realized gain (loss) on settlements oil[a] [b]	285		(7,727)	
Realized gain on settlements NGLs[a] [b]	3,088		3,088	
Realized gain on early settlement of oil derivatives [c]		15,697		15,697
Derivative fair value income	$ 65,762	$ 9,981	$ 77,967	$ 58,860

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

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

(c) Not included in realized prices.

The combined fair value of derivatives included in the accompanying consolidated balance sheets as of September 30, 2011 and December 31, 2010 is summarized below (in thousands). As of September 30, 2011, we have conducted commodity derivative activities with ten financial institutions, of which all but one are secured lenders in our bank credit facility. We believe all of these institutions are acceptable credit risks. At times, such risks may be concentrated with certain counterparties. The credit worthiness of our counterparties is subject to periodic review. In our accompanying consolidated balance sheets, derivative assets and liabilities are netted where derivatives with both gain and loss positions are held by a single counterparty.

	September 30, 2011	December 31, 2010
Derivative assets:		
Natural gas collars	$ 152,501	$ 155,159
collars discontinued operations		8,195

swaps	19,304	
Crude oil collars	(4,340)	
call options	(20,737)	(31,904)
NGL swaps	36,881	
	$ 183,609	$ 131,450
Derivative liabilities:		
Natural gas collars	$	$ 27,032
basis swaps		(352)
swaps		
Crude oil collars		(12,051)
call options		(28,393)
NGL swaps		
	$	$ (13,764)

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

	September 30, 2011			December 31, 2010		
	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:						
Swaps [1]	$ 19,304	$	$ 19,304	$	$	$
Collars[1]	147,067		147,067	164,933		164,933
Collars discontinued operations[1]				8,195		8,195
	$ 166,371	$	$ 166,371	$ 173,128	$	$ 173,128
Derivatives that do not qualify for hedge accounting:						
Swaps [1]	$ 36,881	$	$ 36,881	$	$	$
Collars[1]	5,434	(4,340)	1,094	17,259	(12,052)	5,207
Call options[1]		(20,737)	(20,737)		(60,297)	(60,297)
Basis swaps[1]					(352)	(352)
	$ 42,315	$ (25,077)	$ 17,238	$ 17,259	$ (72,701)	$ (55,442)

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

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

	Three Months Ended September 30,				Nine Months Ended September 30,			
	Change in Hedge Derivative Fair Value		Realized Gain (Loss) Reclassified from OCI into Revenue [a]		Change in Hedge Derivative Fair Value		Realized Gain (Loss) Reclassified from OCI into Revenue [a]	
	2011	2010	2011	2010	2011	2010	2011	2010
Swaps	$ 15,739	$	$	$	$ 17,854	$	$	$
Collars	75,449	109,663	26,758	15,616	97,873	187,593	80,660	35,171
Collars discontinued operations		(12)			412	1	8,607	
Income taxes	(34,195)	(42,683)	(10,034)	(6,014)	(41,609)	(72,301)	(33,476)	(13,445)
	$ 56,993	$ 66,968	$ 16,724	$ 9,602	$ 74,530	$ 115,293	$ 55,791	$ 21,726

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

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

	Three Months Ended September 30,					
	Gain (Loss) Recognized in Income (Non-hedge Derivatives)		Gain (Loss) Recognized in Income (Ineffective Portion)		Derivative Fair Value Income (Loss)	
	2011	2010	2011	2010	2011	2010
Swaps	$ 26,219	$	$	$	$ 26,219	$
Collars	15,828	12,559	(1,935)	2,389	13,893	14,948
Call options	25,650	(3,823)			25,650	(3,823)
Basis swaps		(1,144)				(1,144)
Total	$ 67,697	$ 7,592	$ (1,935)	$ 2,389	$ 65,762	$ 9,981

	Nine Months Ended September 30,					
	Gain (Loss) Recognized in Income (Non-hedge Derivatives)		Gain Recognized in Income (Ineffective Portion)		Derivative Fair Value Income (Loss)	
	2011	2010	2011	2010	2011	2010
Swaps	$ 39,969	$	$	$	$ 39,969	$
Collars	14,693	60,998	7,089	2,048	21,782	63,046
Call options	16,259	(3,823)			16,259	(3,823)
Basis swaps	(43)	(363)			(43)	(363)
Total	$ 70,878	$ 56,812	$ 7,089	$ 2,048	$ 77,967	$ 58,860

(13) FAIR VALUE MEASUREMENTS

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. There are three approaches for measuring the fair value of assets and liabilities: the market approach, the income approach and the cost approach, each of which includes multiple valuation techniques. The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to measure fair value by converting future amounts, such as cash flows or earnings, into a single present value amount using current market expectations about those future amounts. The cost approach is based on the amount that would currently be required to replace the service capacity of an asset. This is often referred to as current replacement cost. The cost approach assumes that the fair value would not exceed what it would cost a market participant to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence.

The fair value accounting standards do not prescribe which valuation technique should be used when measuring fair value and does not prioritize among the techniques. These standards establish a fair value hierarchy that prioritizes the inputs used in applying the various valuation techniques. Inputs broadly refer to the assumptions that market participants use to make pricing decisions, including assumptions about risk. Level 1 inputs are given the highest priority in the fair value hierarchy while Level 3 inputs are given the lowest priority. The three levels of the fair value hierarchy are as follows:

Level 1 Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.

Level 3 Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management s best estimate of fair value.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities 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.

Fair Values-Recurring

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

	Fair Value Measurements at September 30, 2011 Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of September 30, 2011
Trading securities held in our deferred compensation plans	$ 49,199	$	$	$ 49,199
Derivatives swaps		56,185		56,185
collars		148,161		148,161
call options		(20,737)		(20,737)

Our trading securities in Level 1 are exchange-traded and measured at fair value with a market approach using September 30, 2011 market values. Derivatives in Level 2 are measured at fair value with a market approach using third-party pricing services, which have been corroborated with data from active markets or broker quotes.

Our trading securities held in the deferred compensation plan are accounted for using the mark-to-market accounting method and are included in other assets in our accompanying consolidated balance sheets. We elected to adopt the fair value option to simplify our accounting for the investments in our deferred compensation plan. Interest, dividends and mark-to-market gains/losses are included in deferred compensation plan expense in our consolidated statements of operations. For the three months ended September 30, 2011, interest and dividends were $84,000 and mark-to-market was a loss of $7.9 million. For the three months ended September 30, 2010, interest and dividends were $44,000 and mark-to-market was a gain of $3.5 million. For the nine months ended September 30, 2011, interest and dividends were $179,000 and mark-to-market was a loss of $6.6 million. For the nine months ended September 30, 2010 interest and dividends were $118,000 and mark-to-market was a gain of $8.2 million. For additional information on the accounting for our deferred compensation plan, see Note 14.

Fair Values-Nonrecurring

We review our long-lived assets to be held and used, including proved natural gas and oil properties, whenever events or circumstances indicate the carrying value of those assets may not be recoverable. Several long-lived assets held for use were evaluated for impairment during 2011 and 2010 due to reductions in estimated reserves and natural gas prices. The fair value of our onshore Gulf Coast assets in both 2011 and 2010 was measured using an income approach based upon internal estimates of future production levels, prices, drilling and operating costs and discount rates, which are Level 3 inputs. Our projected undiscounted cash flows associated with these assets was less than their carrying value and therefore, we recorded an impairment of $7.5 million in third quarter 2011 and $6.5 million in the nine months 2010 related to our onshore Gulf Coast proved properties.

During third quarter 2011, we evaluated our East Texas properties for impairment which included a consideration for the potential sale of some of these assets, along with a reduction in estimated reserves and lower natural gas prices.

This analysis reflected undiscounted cash flows for these properties was less than their carrying value and we recognized an impairment charge of $31.2 million. Some of these properties were sold in third quarter 2011 for proceeds of $11.0 million.

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The following table presents the value of these assets measured at fair value on a nonrecurring basis (in thousands):

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011		2010		2011		2010	
	Fair Value	Impairment	Fair Value	Impairment	Fair Value	Impairment	Fair Value	Impairment
Natural gas and oil properties	$ 24,388	$ 38,681	$	$	$ 24,388	$ 38,681	$ 16,075	$ 6,505

Fair Values-Reported

The following table presents the carrying amounts and the fair values of our financial instruments as of September 30, 2011 and December 31, 2010 (in thousands):

	September 30, 2011		December 31, 2010	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Assets:				
Commodity swaps, collars, call options and basis swaps	$ 183,609	$ 183,609	$ 123,255	$ 123,255
Commodity collars discontinued operations			8,195	8,195
Marketable securities[(a)]	49,199	49,199	47,794	47,794
Liabilities:				
Commodity swaps, collars, call options and basis swaps			(13,764)	(13,764)
Bank credit facility[(b)]			(274,000)	(274,000)
6.375% senior subordinated notes due 2015[(b)]			(150,000)	(153,000)
7.5% senior subordinated notes due 2016[(b)]			(249,683)	(259,375)
7.5% senior subordinated notes due 2017[(b)]	(250,000)	(265,000)	(250,000)	(263,438)
7.25% senior subordinated notes due 2018[(b)]	(250,000)	(266,250)	(250,000)	(263,750)
8.0% senior subordinated notes due 2019[(b)]	(287,678)	(328,500)	(286,853)	(326,625)
6.75% senior subordinated notes due 2020[(b)]	(500,000)	(532,500)	(500,000)	(515,625)
5.75% senior subordinated notes due 2021[(b)]	(500,000)	(518,750)		

(a) Marketable securities are held in our deferred compensation plans.

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

Concentration of Credit Risk

Most of our receivables are from a diverse group of companies, including major energy companies, pipeline companies, local distribution companies, financial institutions and end-users in various industries. Letters of credit or other appropriate security are obtained as deemed necessary to limit risk of loss. Our allowance for uncollectible receivables was $4.2 million at September 30, 2011 and $5.0 million at December 31, 2010. Commodity-based contracts expose us to the credit risk of nonperformance by the counterparty to the contracts. As of September 30, 2011, these contracts consist of swaps, collars and call options. 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 ten financial institutions, of which all but one are secured lenders in our bank credit facility. At September 30, 2011, our net derivative receivable includes a receivable from the one counterparty not included in our bank credit facility of $15.4 million. Our natural gas and oil properties provide collateral under our credit facility and our derivative exposure. None of our derivative contracts have margin requirements or collateral provisions that would require funding prior to the scheduled cash settlement date.

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(14) EMPLOYEE BENEFIT AND EQUITY PLANS

We have two active equity-based stock compensation plans. Under these plans, incentive and non-qualified stock options, SARs, restricted stock, restricted stock units, phantom stock and various other awards may be issued to employees and directors pursuant to decisions of the Compensation Committee, which is made up of non-employee, independent directors from the Board of Directors.

SARs/Stock Option Awards

All awards granted have been issued at prevailing market prices at the time of the grant. Information with respect to stock option/SARs activity is summarized below:

	Shares	Weighted Average Exercise Price
Outstanding at December 31, 2010	6,461,839	$ 37.20
Granted	842,620	51.16
Exercised	(2,058,626)	31.00
Expired/forfeited	(209,051)	53.58
Outstanding at September 30, 2011	5,036,782	$ 41.39

The weighted average fair value of a SAR to purchase one share of common stock granted during 2011 was $18.21. The fair value of each SAR granted during 2011 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 1.4%; dividend yield of 0.3%; expected volatility of 47% and an expected life of 3.6 years. Of the 5.0 million stock option/SARs outstanding at September 30, 2011, 647,000 are stock options and 4.4 million are SARs.

Restricted Stock Awards

Equity Awards

Beginning in first quarter 2011, the compensation committee began granting restricted stock units under our equity-based stock compensation plans. These restricted stock units vest over a three-year period. All awards granted have been issued at prevailing market prices at the time of grant and the vesting of these shares is based upon an employee s continued employment with us.

Liability Awards

These restricted stock shares are placed into our deferred compensation plan when granted. In the first nine months of 2011, 334,200 shares of restricted stock (or non-vested shares) were issued to certain employees at an average price of $51.11 with a three-year vesting period and 15,500 shares were granted to directors at an average price of $52.35 with immediate vesting. In the first nine months of 2010, we issued 392,000 shares of restricted stock as compensation to employees at an average price of $45.85 with a three-year vesting period and 21,000 shares were granted to our directors at an average price of $45.51 with immediate vesting. All restricted stock awards held in our deferred compensation plans are classified as a liability award and the vested shares are remeasured at fair value each reporting period. This mark-to-market is included in deferred compensation plan expense in our accompanying consolidated statements of operations (see deferred compensation plan 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.

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A summary of the status of our non-vested restricted stock outstanding at September 30, 2011 is presented below:

	Equity Awards			Liability Awards		
	Shares		Weighted Average Grant Date Fair Value	Shares		Weighted Average Grant Date Fair Value
Outstanding at December 31, 2010		$		582,751	$	44.81
Granted	329,599		49.47	349,674		51.16
Vested	(63,199)		49.32	(313,388)		45.94
Forfeited	(14,612)		49.57	(26,874)		45.08
Outstanding at September 30, 2011	251,788	$	49.50	592,163	$	47.95

Deferred Compensation Plan

Our deferred compensation plan gives directors, officers and key employees the ability to defer all or a portion of their salaries and bonuses and invest such amounts in our common stock or make other investments at the individual s discretion. The assets of the plan are held in a grantor trust, which we refer to as the Rabbi Trust, and are therefore available to satisfy the claims of our creditors in the event of bankruptcy. Our stock granted and held in the Rabbi Trust is treated as a liability award as employees are allowed to take withdrawals either in cash or in our stock. The liability associated with the vested portion of our stock is adjusted to fair value each reporting period by a charge or credit to deferred compensation plan expense on our consolidated statements of operations. The assets of the Rabbi Trust, other than our common stock, are invested in marketable securities and reported at market value in other assets in the accompanying consolidated balance sheets. Changes in the market value of the marketable securities are charged or credited to deferred compensation plan expense each quarter. The deferred compensation liability included in our consolidated balance sheets reflects the vested market value of the marketable securities and Range common stock held in the Rabbi Trust. We recorded non-cash, mark-to-market expense related to our deferred compensation plan of $8.7 million in the three months ended September 30, 2011, compared to income of $5.3 million in the same period of 2010. We recorded non-cash mark-to-market expense related to our deferred compensation plan of $33.6 million in the nine months ended September 30, 2011 compared to income of $25.2 million in the same period of 2010.

(15) SUPPLEMENTAL CASH FLOW INFORMATION

	Nine Months Ended September 30,	
	2011	2010
	(in thousands)	
Non-cash investing and financing activities included:		
Asset retirement costs capitalized, net	$ 13,569	$ 1,229
Unproved property purchased with stock [a]		20,000
Net cash provided from operating activities included:		
Interest paid	$ 95,536	$ 74,732
Income taxes paid (refunded)	309	(807)

[a] Nine months ended September 30, 2010 included shares that were issued in January 2010 while the value was accrued and included in costs incurred for the year ended December 31, 2009.

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(16) COMMITMENTS AND CONTINGENCIES

Litigation

We are involved in various legal actions, claims and other regulatory proceedings 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. If an unfavorable ruling were to occur, there exists the possibility of a material adverse impact on our net income or loss in the period in which the ruling occurs. We provide accruals for litigation and claims if we determine that the loss is probable and the amount can be reasonably estimated.

Transportation Contracts

As of September 30, 2011, future minimum transportation fees under our gas transportation commitments are as follows (in thousands):

	Transportation Commitments
2011 (remaining)	$ 22,880
2012	91,235
2013	90,588
2014	90,113
2015	87,182
Thereafter	510,508
	$ 892,506

Other

During third quarter 2011, we entered into a two-year agreement for hydraulic fracturing services, including related equipment, material and labor for $17.5 million in 2011, $70.1 million in 2012 and $52.6 million in 2013.

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

	September 30, 2011	December 31, 2010
	(in thousands)	
Natural gas and oil properties:		
Properties subject to depletion	$ 5,689,410	$ 4,742,248
Unproved properties	730,620	648,143
Total	6,420,030	5,390,391
Accumulated depreciation, depletion and amortization	(1,573,195)	(1,306,378)
Net capitalized costs	$ 4,846,835	$ 4,084,013

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

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

	Nine Months Ended September 30, 2011	Year Ended December 31, 2010
	(in thousands)	
Acquisitions:		
Unproved leasehold	$	$ 3,697
Proved properties	542	130,767
Asset retirement obligations		556
Acreage purchases	144,652	151,572
Development	762,067	727,720
Exploration:		
Drilling	136,181	50,433
Expense	53,270	56,298
Stock-based compensation expense	3,115	4,209
Gas gathering facilities:		
Development	37,072	19,627
Subtotal	1,136,899	1,144,879
Asset retirement obligations	13,568	(6,370)
Total costs incurred continuing operations	1,150,467	1,138,509
Discontinued operations	3,245	73,369
Total costs incurred	$ 1,153,712	$ 1,211,878

(a) Includes costs incurred whether capitalized or expensed and also includes our Barnett Shale operations.

(19) OFFICE CLOSING AND EXIT ACTIVITIES

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

The following table details our exit activities, which are included in accrued liabilities in the accompanying consolidated balance sheets as of September 30, 2011 and December 31, 2010 (in thousands):

	Nine Months Ended September 30, 2011	Year Ended December 31, 2010

	(in thousands)	
Balance at beginning of period	$ 1,092	$ 1,568
Accrued one-time termination costs		5,138
Office lease	(117)	514
Payments	(852)	(6,128)
Balance at end of period	$ 123	$ 1,092

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

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. Certain sections of Management s Discussion and Analysis of Financial Condition and Results of Operations include forward-looking statements concerning trends or events potentially affecting our business. These statements typically contain words such as anticipates, believes, estimates, expects, targets, pla could, may, should, would or similar words indicating that future outcomes are uncertain. In accordance with safe harbor provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, which could cause future outcomes to differ materially from those set forth in forward-looking statements. These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. While management believes that these forward-looking statements are reasonable as and when made, there can be no assurance that future developments affecting us will be those that we anticipate. All comments concerning our expectations for future revenues and operating results are based on our forecasts for our existing operations and do not include the potential impact of any future acquisitions. For additional risk factors affecting our business, see Item 1A. Risk Factors as filed with our Annual Report on Form 10-K for the year ended December 31, 2010 filed with the SEC on March 1, 2011.

Critical Accounting Estimates and Policies

The preparation of financial statements in accordance with generally accepted accounting principles requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Actual results could differ from the estimates and assumptions used. These policies and estimates are described in our Current Report on Form 8-K for the year ended December 31, 2010 filed with the SEC on May 6, 2011. We have identified the following critical accounting policies and estimates used in the preparation of our financial statements: accounting for natural gas, NGL and oil revenue, natural gas and oil properties, stock-based compensation, derivative financial instruments, asset retirement obligations and deferred income taxes.

Market Conditions

Prices for natural gas, natural gas liquids (NGLs) and oil that we produce significantly impact our revenues and cash flows. Commodity prices can fluctuate widely. The following table lists average New York Mercantile Exchange (NYMEX) prices for natural gas and oil for the three months and nine months ended September 30, 2011 and 2010.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Average NYMEX prices[(a)]				
Natural gas (per mcf)	$ 4.18	$ 4.42	$ 4.22	$ 4.61
Oil (per bbl)	89.54	76.18	95.47	77.62

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

Consolidated Results of Operations

Overview

We are an independent natural gas and oil company engaged in the exploration, development and acquisition of natural gas and oil properties, mostly in the Appalachia and Southwest regions of the United States. Our objective is to build stockholder value through consistent growth in reserves and production on a cost-efficient basis. Our strategy to achieve our objective is to increase reserves and production through internally generated drilling projects occasionally coupled with complementary acquisitions. Our revenues, profitability and future growth depend substantially on prevailing prices for natural gas, NGLs and oil and on our ability to economically find, develop, acquire and produce natural gas and oil reserves. To reduce our exposure to fluctuations in the prices of natural gas, NGLs and oil, we currently, and may in the future, enter into derivative contracts. Reducing our exposure to price volatility helps ensure that we have adequate funds available for our capital program. We use the successful efforts method of accounting for our natural gas, NGLs and oil activities. Our corporate headquarters is located in Fort Worth, Texas. Discontinued operations consist of our Barnett Shale properties which were sold in April and August of 2011. Unless otherwise indicated, the information included herein relates to our continuing operations.

During the first nine months of 2011, we achieved the following financial and operating results from our continuing operations:

- achieved 31% year-over-year production growth;
- daily production now exceeds 534.4 mmcfe per day;
- natural gas, NGL and oil sales increased 38% from the first nine months 2010;
- reduced our DD&A rate 8% from the first nine months 2010;
- year-over-year direct operating expense per mcfe decreased 3% while production and ad valorem tax expense per mcfe declined 11% and general and administrative expense per mcfe declined 17%;
- sold substantially all of our Barnett Shale properties for gross proceeds of $889.3 million, including assumed hedges;
- sold non-strategic properties in East Texas and Pennsylvania for proceeds of $17.0 million;
- entered into additional commodity derivative contracts for 2011, 2012 and 2013;
- renewed our bank credit facility with a borrowing base of $2.0 billion;
- issued $500.0 million of new 5.75% senior subordinated notes, at par; and
- used the proceeds from the issuance of $500.0 million of new 5.75% senior subordinated notes to retire all $150.0 million principal amount of our 6.375% senior subordinated notes due 2015 and all $250.0 million principal amount of our 7.5% senior subordinated notes due 2016.

Third Quarter Highlights

Total revenues increased $143.1 million, or 73% for third quarter 2011 over the same period of 2010. The increase includes an $84.0 million increase in natural gas, NGL and oil sales and an increase in derivative fair value income of $55.8 million. Natural gas, NGL and oil sales vary due to changes in volumes of production sold and realized commodity prices. Realized prices increased an average of 6% from the same period last year. Production increased 35% including a 35% increase in NGL production primarily due to increased liquids-rich production in our Appalachia area. For third quarter 2011, production increased 35% while realized prices (including all derivative settlements) increased 6%. In third quarter 2011, we completed the sale of the remainder of our Barnett Shale properties for total cash proceeds of $12.4 million. See also Notes 4 and 5 for specific information on the sale of these assets including their treatment as discontinued operations. In the third quarter 2011, we sold various East Texas producing properties for proceeds of $11.0 million and certain Pennsylvania producing properties for proceeds of $6.0 million.

We continue to believe natural gas, NGL and oil prices will remain volatile and will be affected by, among other things, weather, the U.S. and worldwide economy, new regulations, new technology, the level of natural gas and oil production in North America and worldwide political conditions in natural gas and oil producing regions. Although we have entered into derivative contracts covering a portion of our production volumes for 2011, 2012 and 2013, a sustained lower price environment would result in lower realized prices for unprotected volumes and reduce the prices we can enter into derivative contracts for additional volumes in the future.

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

Our natural gas, NGL and oil sales vary from quarter to quarter as a result of changes in realized commodity prices and volumes of production sold. Hedges included in natural gas, NGL and oil sales reflect settlements on those derivatives that qualify for hedge accounting. The cash settlement of derivative contracts that are not accounted for as hedges are included in derivative fair value income in the accompanying consolidated statements of operations. The following table summarizes the primary components of natural gas, NGL and oil sales for the three months and nine months ended September 30, 2011 and 2010 (in thousands):

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	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011	2010	Change	%	2011	2010	Change	%
Gas wellhead	$ 135,133	$ 105,448	$ 29,685	28%	$ 364,716	$ 323,975	$ 40,741	13%
Gas hedges realized	26,758	15,616	11,142	71%	80,659	35,148	45,511	129%
Total gas sales	161,891	121,064	40,827	34%	445,375	359,123	86,252	24%
NGLs	67,447	36,450	30,997	85%	184,520	91,876	92,644	101%
Oil wellhead	42,461	30,243	12,218	40%	125,472	97,561	27,911	29%
Oil hedges realized				%		23	(23)	(100%)
Total oil sales	42,461	30,243	12,218	40%	125,472	97,584	27,888	29%
Combined wellhead	245,041	172,141	72,900	42%	674,708	513,412	161,296	31%
Combined hedges realized	26,758	15,616	11,142	71%	80,659	35,171	45,488	129%
Total natural gas, NGL and oil sales	$ 271,799	$ 187,757	$ 84,042	45%	$ 755,367	$ 548,583	$ 206,784	38%

Our production continues to grow through continued drilling success as we place new wells into production, partially offset by the natural decline of our wells and asset sales. For third quarter 2011, total production volumes, when compared to the same period of the prior year, increased 54% in our Appalachia area and decreased 3% in our Southwest area. For each of the three months and nine months ended September 30, 2011, NGL production increased from the same period of the prior year primarily due to increased liquids-rich gas production in our Appalachia area along with an increase in processing capacity in the region. For the nine months ended September 30, 2011, our production volumes, as compared to the same period of the prior year, increased 47% in our Appalachia area and remained the same in our Southwest area. Our production for the three months and nine months ended September 30, 2011 and 2010 is shown below:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011	2010	Change	%	2011	2010	Change	%
Production [(a)]:								
Natural gas (mcf)	37,441,857	27,350,286	10,091,571	37%	100,058,851	77,148,685	22,910,166	30%
NGLs (bbls)	1,430,568	1,059,485	371,083	35%	3,798,635	2,398,684	1,399,951	58%
Crude oil (bbls)	523,074	453,147	69,927	15%	1,462,168	1,432,805	29,363	2%
Total (mcfe)[(b)]	49,163,709	36,426,083	12,737,626	35%	131,623,669	100,137,624	31,486,045	31%

Average daily production [(a)]:								
Natural gas (mcf)	406,977	297,286	109,691	37%	366,516	282,596	83,920	30%
NGLs (bbls)	15,550	11,516	4,034	35%	13,914	8,786	5,128	58%
Crude oil (bbls)	5,686	4,926	760	15%	5,356	5,248	108	2%
Total (mcfe) [(b)]	534,388	395,936	138,452	35%	482,138	366,804	115,334	31%

(a) Represents volumes sold regardless of when produced.

(b) NGLs and oil are converted at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil and natural gas, which is not indicative of the relationship between oil and natural gas prices.

Our average realized price (including all derivative settlements) received was $5.75 per mcfe in third quarter 2011 compared to $5.43 per mcfe in the same period of the prior year. Our average realized price (including all derivative settlements) received was $5.80 per mcfe in the nine months ended September 30, 2011 compared to $5.65 per mcfe in the same period of the prior year. Our average realized price calculation (including all derivative settlements) includes all cash settlements for derivatives, whether or not they qualify for hedge accounting. Average price calculations for the three months and nine months ended September 30, 2011 and 2010 are shown below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Average sales prices (wellhead):				
Natural gas (per mcf)	$ 3.61	$ 3.86	$ 3.65	$ 4.20
NGLs (per bbl)	47.15	34.40	48.58	38.30
Crude oil (per bbl)	81.18	66.74	85.81	68.08
Total (per mcfe)[a]	4.98	4.73	5.13	5.13
Average realized price (including derivatives that qualify for hedge accounting):				
Natural gas (per mcf)	$ 4.32	$ 4.43	$ 4.45	$ 4.65
NGLs (per bbl)	47.15	34.40	48.58	38.30
Crude oil (per bbl)	81.18	66.74	85.81	68.11
Total (per mcfe)[a]	5.53	5.15	5.74	5.48
Average realized price (including all derivative settlements):				
Natural gas (per mcf)	$ 4.52	$ 4.80	$ 4.58	$ 4.87
NGLs (per bbl)	49.31	34.40	49.39	38.30
Crude oil (per bbl)	81.72	66.74	80.53	68.11
Total (per mcfe)[a]	5.75	5.43	5.80	5.65

(a) NGLs and oil are converted at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil and natural gas, which is not indicative of the relationship between oil and natural gas prices.

Derivative fair value income was $65.8 million in third quarter 2011 compared to $10.0 million in the same period of 2010. Derivative fair value income was $78.0 million in the nine months ended September 30, 2011 compared to $58.9 million in the same period of 2010. Some of our derivatives do not qualify for hedge accounting and are accounted for using the mark-to-market accounting method whereby all realized and unrealized gains and losses related to these contracts are included in derivative fair value income in the accompanying consolidated statements of operations. Mark-to-market accounting treatment creates volatility in our revenues as unrealized gains and losses from non-hedge derivatives are included in total revenues and are not included in accumulated other comprehensive income in the accompanying consolidated balance sheets. Hedge ineffectiveness, also included in this statement of operations category, is associated with our hedging contracts that qualify for hedge accounting.

The following table presents information about the components of derivative fair value income for the three months and nine months ended September 30, 2011 and 2010 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Hedge ineffectiveness realized[c]	$ 2,036	$	$ 4,558	$ (352)
unrealized[a]	(3,971)	2,389	2,531	2,400
Change in fair value of derivatives that do not qualify for hedge accounting[a]	58,990	(18,284)	67,093	23,885
Realized gain on settlements gas[b][c]	5,334	10,179	8,424	17,230
Realized gain (loss) on settlements oil[b][c]	285		(7,727)	
Realized gain on settlements NGLs[b][c]	3,088		3,088	
Realized gain on early settlement of oil derivatives[d]		15,697		15,697
Derivative fair value income	$ 65,762	$ 9,981	$ 77,967	$ 58,860

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

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

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

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

Gain (loss) on the sale of assets for third quarter 2011 increased $136,000 from the same period of the prior year. For the nine months ended September 30, 2011, we recorded a $1.7 million loss related to the sale of certain derivatives included with the sale of our Barnett Shale properties and we received proceeds of $40.0 million. For the nine months ended September 30, 2010, we recorded a gain of $77.4 million from the sale of our Ohio properties and we received proceeds of $323.0 million.

Other income (loss) for third quarter 2011 was a loss of $375,000 compared to a loss of $1.0 million in the same period of 2010. Third quarter 2011 includes loss from equity method investments of $641,000. The third quarter of 2010 includes a loss from equity method investments of $845,000. Other income (loss) for the nine months ended September 30, 2011 increased from a loss of $1.9 million in 2010 to income of $268,000 in 2011. The nine months ended September 30, 2011 includes proceeds from settlements of various lawsuits and refunds partially offset by a loss from equity method investments of $1.4 million. The nine months ended September 30, 2010 includes a loss from equity method investments of $1.8 million.

We believe some of our expense fluctuations are best analyzed on a unit-of-production, or per mcfe, basis. The following presents information about these expenses on a per mcfe basis for the three months and the nine months ended September 30, 2011 and 2010:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011	2010	Change	%	2011	2010	Change	%
Direct operating expense	$ 0.61	$ 0.70	$ (0.09)	(13%)	$ 0.66	$ 0.68	$ (0.02)	(3%)
Production and ad valorem tax expense	0.15	0.19	(0.04)	(21%)	0.17	0.19	(0.02)	(11%)
General and administrative expense	0.73	1.00	(0.27)	(27%)	0.83	1.00	(0.17)	(17%)
Interest expense	0.70	0.64	0.06	9%	0.69	0.65	0.04	6%
Depletion, depreciation and amortization expense	1.90	1.91	(0.01)	(1%)	1.85	2.02	(0.17)	(8%)

Direct operating expense increased $4.3 million in third quarter 2011 to $29.8 million. We experience increases in operating expenses as we add new wells and maintain production from existing properties. We incurred $1.2 million ($0.03 per mcfe) of workover costs in third quarter 2011 versus $736,000 ($0.02 per mcfe) in 2010. On a per mcfe basis, direct operating expenses for third quarter 2011 decreased $0.09, or 13%, from the same period of 2010 with the decrease primarily due to lower well service costs ($0.07) and lower well equipment costs ($0.02 per mcfe), which were partially offset by higher workover costs ($0.01 per mcfe).

Direct operating expense increased $18.5 million in the first nine months 2011 to $87.1 million. We incurred $2.2 million ($0.02 per mcfe) of workover costs in the first nine months of 2011 compared to $2.5 million ($0.03 per mcfe) in the same period of 2010. On a per mcfe basis, direct operating expense decreased $0.02 or 3% from the same period of the prior year with the decrease consisting primarily of lower well service costs ($0.03 per mcfe), lower workover costs ($0.01 per mcfe) and the impact of the sale of certain higher operating cost assets during 2010. We expect to experience lower costs on a per mcfe basis as we increase production from our Marcellus Shale wells due to their lower operating costs relative to our other operating areas. Stock-based compensation included in this category represents amortization of restricted stock grants and expense related to SAR grants.

The following table summarizes direct operating expenses per mcfe for the three months and nine months ended September 30, 2011 and 2010:

	Three Months Ended September 30,	Nine Months Ended September 30,

	2011	2010	Change	%	2011	2010	Change	%
Lease operating expense	$ 0.57	$ 0.67	$ (0.10)	(15%)	$ 0.63	$ 0.64	$ (0.01)	(2%)
Workovers	0.03	0.02	0.01	50%	0.02	0.03	(0.01)	(33%)
Stock-based compensation (non-cash)	0.01	0.01		%	0.01	0.01		%
Total direct operating expenses	$ 0.61	$ 0.70	$ (0.09)	(13%)	$ 0.66	$ 0.68	$ (0.02)	(3%)

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Production and ad valorem taxes are paid based on market prices and not hedged prices. For third quarter 2011, these taxes increased $414,000 or 6% from the same period of the prior year with higher prices partially offset by an increase in production volumes not subject to production taxes. On a per mcfe basis, production and ad valorem taxes per mcfe decreased to $0.15 in third quarter 2011 compared to $0.19 in the same period of 2010. For the first nine months of 2011, these taxes increased $2.6 million or 14% from the same period of the prior year due to a decrease in the number of wells receiving high cost tax credits and higher NGL production volumes subject to production taxes which was partially offset by an increase in production volumes not subject to production taxes and lower prices. On a per mcfe basis, production and ad valorem taxes decreased to $0.17 in the first nine months of 2011 compared to $0.19 in the same period of 2010.

General and administrative expense for third quarter 2011 decreased $616,000 or 2% from the same period of the prior year due primarily to lower community relations costs ($3.6 million), which were partially offset by higher stock-based compensation ($670,000), higher legal costs ($750,000) and higher bad debt expense ($850,000). General and administrative expense for the first nine months of 2011 increased $8.5 million or 8% from the same period of the prior year primarily due to higher stock-based compensation ($1.1 million), higher salaries and benefits ($2.9 million), higher legal fees ($940,000), higher bad debt expense ($446,000) and higher office expenses, including information technology. Stock-based compensation included in this category represents amortization of restricted stock grants and expense related to SAR grants. The following table summarizes general and administrative expenses per mcfe for the three months and the nine months ended September 30, 2011 and 2010:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011	2010	Change	%	2011	2010	Change	%
General and administrative	$ 0.56	$ 0.79	$ (0.23)	(29%)	$ 0.62	$ 0.74	$ (0.12)	(16%)
Stock-based compensation (non-cash)	0.17	0.21	(0.04)	(19%)	0.21	0.26	(0.05)	(19%)
Total general and administrative expenses	$ 0.73	$ 1.00	$ (0.27)	(27%)	$ 0.83	$ 1.00	$ (0.17)	(17%)

Interest expense for third quarter 2011 increased $10.8 million from the same period of the prior year due to the refinancing of certain debt from floating to higher fixed rates. In May 2011, we issued $500.0 million of new 5.75% senior subordinated notes due 2021, and used a portion of the proceeds to retire our 6.375% senior subordinated notes due 2015 and our 7.5% senior subordinated notes due 2016 to better match the maturities of our debt with the life of our properties, which added $7.2 million of interest costs in third quarter 2011. A portion of the proceeds were also used for general corporate purposes. In August 2010, we issued $500.0 million of 6.75% senior subordinated notes due 2020, which added $4.6 million of interest costs in third quarter 2010. The third quarter 2010 includes $10.4 million of interest costs allocated to discontinued operations. There was no outstanding bank debt for third quarter 2011 compared to average bank debt outstanding of $361.1 million for the same period of the prior year. The weighted average interest rate was 2.3% in the third quarter 2010.

Interest expense for the nine months increased $24.8 million from the same period of the prior year due to the refinancing of certain debt from floating to higher fixed rates. In May 2011, we issued $500.0 million of 5.75% senior subordinated notes due 2021, which added $10.1 million of interest costs in the first nine months of 2011. In August 2010, we issued $500.0 million of 6.75% senior subordinated notes due 2020, which added $4.6 million of interest costs in the first nine months of 2011. Average debt outstanding on the credit facility for the first nine months 2011 was $197.5 million compared to $380.6 million for the same period of the prior year and the weighted average interest rate was 2.2% in both the nine months periods ending September 30, 2011 and 2010. The nine months ending

September 30, 2011 includes $14.8 million allocated to discontinued operations compared to $29.3 million in the same period of the prior year.

Depletion, depreciation and amortization (DD&A) increased $23.9 million, or 34%, to $93.6 million in third quarter 2011. The increase was due to a 35% increase in production. On a per mcfe basis, DD&A decreased from $1.91 in third quarter 2010 to $1.90 in third quarter 2011. Depletion expense for third quarter 2011 includes an adjustment of $4.2 million to record prior years depletion related to our Oklahoma properties. Excluding this adjustment, the DD&A rate would have been $1.82 per mcfe for third quarter 2011 and $1.82 per mcfe for the first nine months 2011. In the first nine months of 2011, DD&A increased $41.8 million with a 31% increase in production partially offset by a 7% decrease in depletion rates. Depletion rates are declining due to our lower finding and development costs and the mix of our production. The following table summarizes DD&A expense per mcfe for the three months and the nine months ended September 30, 2011 and 2010:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011	2010	Change	%	2011	2010	Change	%
Depletion and amortization	$ 1.77	$ 1.77	$	%	$ 1.73	$ 1.86	$ (0.13)	(7%)
Depreciation	0.08	0.11	(0.03)	(27%)	0.08	0.12	(0.04)	(33%)
Accretion and other	0.05	0.03	0.02	67%	0.04	0.04		%
Total DD&A expense	$ 1.90	$ 1.91	$ (0.01)	(1%)	$ 1.85	$ 2.02	$ (0.17)	(8%)

Our total operating expenses also include other expenses that generally do not trend with production. These expenses include stock-based compensation, exploration expense, abandonment and impairment of unproved properties, termination costs, deferred compensation plan expenses and impairment of proved properties. In the three months ended September 30, 2011 and 2010, stock-based compensation represents the amortization of restricted stock grants, restricted stock units and expenses related to SAR grants. In third quarter 2011, stock-based compensation is a component of direct operating expense ($463,000), exploration expense ($902,000) and general and administrative expense ($8.5 million) for a total of $10.2 million. In third quarter 2010, stock-based compensation was a component of direct operating expense ($544,000), exploration expense ($1.0 million) and general and administrative expense ($7.8 million) for a total of $9.7 million. In the nine months ended September 30, 2011, stock-based compensation is a component of direct operating expense ($1.4 million), exploration expense ($3.2 million) and general and administrative expense ($27.5 million) for a total of $33.2 million. In the nine months ended September 30, 2010, stock-based compensation is a component of direct operating expense ($1.5 million), exploration expense ($3.2 million) and general and administrative expense ($26.4 million) for a total of $32.0 million.

Exploration expense increased $2.4 million in third quarter 2011 and increased $12.6 million in the first nine months of 2011 from the same periods of the prior year. The three months ended September 30, 2011 includes higher seismic and dry hole costs partially offset by lower delay rentals. The nine months ended September 30, 2011 includes higher seismic costs, higher personnel and dry hole costs partially offset by lower delay rentals. The delay rental payments, or costs to defer the commencement of drilling, are primarily attributed to our Marcellus Shale operations. The following table details our exploration-related expenses for the three months and nine months ended September 30, 2011 and 2010 (in thousands):

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011	2010	Change	%	2011	2010	Change	%
Dry hole expense	$ 2,508	$ 1,662	$ 846	51%	$ 2,515	$ 1,661	$ 854	51%
Seismic	8,619	6,428	2,191	34%	26,156	14,474	11,682	81%
Personnel expense	3,058	2,884	174	6%	10,234	8,524	1,710	20%
Stock-based compensation expense	849	1,026	(177)	(17%)	3,115	3,231	(116)	(4%)
Delay rentals and other	2,572	3,225	(653)	(20%)	14,365	15,894	(1,529)	(10%)
Total exploration expense	$ 17,606	$ 15,225	$ 2,381	16%	$ 56,385	$ 43,784	$ 12,601	29%

Abandonment and impairment of unproved properties expense was $16.6 million during the three months ended September 30, 2011 compared to $14.4 million during the same period of 2010. Abandonment and impairment of unproved properties was $52.1 million in the nine months ended September 30, 2011 compared to $30.7 million in the same period of the prior year. We assess individually significant unproved properties for impairment on a quarterly basis and recognize a loss where circumstances indicate impairment in value. In determining whether a significant unproved property is impaired we consider numerous factors including, but not limited to, current exploration plans, favorable or unfavorable activity on the property being evaluated and/or adjacent properties, our geologists evaluation of the property and the remaining months in the lease term for the property. Impairment of individually insignificant unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. The increase from the prior year is primarily due to increasing expirations in our Marcellus Shale area.

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

Deferred compensation plan expense was $8.7 million in third quarter 2011 compared to income of $5.3 million in the same period of the prior year. This non-cash expense relates to the increase or decrease in value of the liability associated with our common stock that is vested and held in the deferred compensation plan. Our deferred compensation liability is adjusted to fair value by a charge or a credit to deferred compensation plan expense in the accompanying statements of operations. Our stock price increased from $55.50 at June 30, 2011 to $58.46 at September 30, 2011. During the same period in the prior year, our stock price decreased from $40.15 at June 30, 2010 to $38.13 at September 30, 2010. Deferred compensation plan expense was $33.6 million in the nine months ended September 30, 2011 compared to income of $25.2 million in the same period of the prior year. Our stock price increased from $44.98 at December 31, 2010 to $58.46 at September 30, 2011. During the same nine month period of the prior year our stock price decreased from $49.85 at December 31, 2009 to $38.13 at September 30, 2010.

Loss on early extinguishment of debt for the nine months ended September 30, 2011 was $18.6 million. In May and June 2011, we purchased or redeemed our 6.375% senior subordinated notes due 2015 at a price equal to 102.31% and we purchased or redeemed our 7.5% senior subordinated notes due 2016 at a price equal to 103.95%. We recorded a loss on extinguishment of debt of $18.6 million which includes a call premium and other consideration of $13.3 million and expensing of related deferred financing costs on the repurchased debt. Loss on early extinguishment of debt for the third quarter and the nine months ended September 30, 2010 was $5.4 million. In August 2010 we redeemed our 7.375% senior subordinated notes due 2013 at a redemption price equal to 101.22%. We recorded a loss on extinguishment of debt of $5.4 million, which includes call premium costs of $2.5 million and expensing of related deferred financing costs on the repurchased debt.

Impairment of proved properties for the three months ended September 30, 2011 was $38.7 million which includes an impairment of $31.2 million related to our East Texas properties and $7.5 million related to our Gulf Coast onshore properties. Our analysis of these properties reflected undiscounted cash flows for these properties were less than their carrying value. We compared the carrying value to their estimated fair value and recognized an impairment charge. These assets were evaluated for impairment due to declining reserves and natural gas prices and in the case of the East Texas properties, the possibility of a sale. Impairment of proved properties for the nine months ended September 30, 2011 was $38.7 million compared to $6.5 million in the nine months ended September 30, 2010. Impairment in the nine months ended September 30, 2010 relates to our Gulf Coast onshore properties. Our estimated fair value of producing properties is generally calculated as the discounted present value of future net cash flows. In 2011 and 2010, our estimates of cash flow were based on the latest available proved reserves and production information and management s estimates of future product prices and costs, which is based on available information such as forward strip prices, at the time of the impairment.

Income tax expense for the three months ended September 30, 2011 increased to $22.5 million from $784,000 in third quarter 2010, reflecting a $52.3 million increase in continuing income from operations before taxes compared to the same period of 2010. Third quarter 2011 provided for tax expense at an effective rate of 40.4% compared to tax expense at an effective rate of 22.8% in the same period of 2010. Income tax expense for the first nine months 2011 decreased to $35.3 million from $61.6 million in the first nine months 2010, reflecting a 49% decrease in continuing income from operations before taxes. The first nine months 2011 provided for tax expense at an effective rate of 43.7% compared to an effective tax rate of 38.6% in the same period of 2010. We expect our effective tax rate to be approximately 40% for the remainder of 2011. Our overall effective tax rate is higher than the statutory rate of 35% due to state income taxes, valuation allowances and other permanent differences.

Discontinued operations for the first nine months of 2011 includes the operating results of our Barnett properties through the date of sale and a pre-tax gain of $4.9 million recorded on the sale. See also Notes 4 and 5 for specific information regarding our discontinued operations.

Capital Resources, Liquidity and Financial Condition

Capital Resources

Our primary capital resources are net cash provided by operating activities, proceeds from the sale of assets and proceeds from financing activities. If internal cash flow and cash on hand do not meet our expectations, we may reduce our level of capital expenditures, and/or fund a portion of our capital expenditures under our bank credit facility, issue debt or equity securities and/or sell assets.

Cash Flow

Cash flows from operating activities primarily are affected by production and commodity prices, net of the effects of settlements of our derivatives. Our cash flows from operating activities also are impacted by changes in working capital. We sell substantially all of our natural gas, NGL and oil production at the wellhead under floating market price contracts. From time to time, we enter into various derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future natural gas, NGL and oil production. The production that we hedge has and will continue to vary from year to year depending on, among other things, our expectation of future commodity prices. Any payments due to counterparties under our derivative contracts should ultimately be funded by prices received from the sale of our production. Production receipts, however, often lag payments to the counterparties. Any interim cash needs can be funded by borrowing under the credit facility. As of September 30, 2011, we have entered into derivative agreements covering 38.9 Bcfe for 2011, 120.7 Bcfe for 2012 and 58.4 Bcfe for 2013.

Net cash provided from continuing operations for the nine months ended September 30, 2011 was $393.1 million compared to $329.8 million in the nine months ended September 30, 2010. Cash flow from continuing operations for the first nine months of 2011 was higher than the same period of the prior year, as higher production from development activity, higher realized prices and a $23.0 million equity method investment distribution was partially offset by higher operating costs. 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 our consolidated statements of cash flows) in the nine months ended September 30, 2011 was a decrease of $72.7 million compared to an increase of $12.4 million in the same period of the prior year.

During the second and third quarters of 2011, we completed the sale of primarily all of our Barnett Shale properties for gross cash proceeds of $889.3 million, including assumed hedges and before post-closing adjustments, resulting in a pretax gain of $4.9 million. The net cash proceeds from the sale of these assets were determined in accordance with the purchase and sale agreement which provides for certain customary adjustments for matters occurring after the effective date of the sale, such as capital contributions and working capital adjustments. Differences between actual working capital amounts and estimated working capital amounts recorded as of September 30, 2011 will be recorded as income or loss from discontinued operations in future periods.

Net cash used in financing activities for the nine months ended September 30, 2011 was $256.3 million compared to net cash provided from financing activities of $128.3 million in the same period of 2010. During the nine months ended September 30, 2011, we:

- borrowed $490.8 million and repaid $764.8 million under our bank credit facility, ending the period with no outstanding borrowings under our credit facility;
- issued $500.0 million principal amount of 5.75% senior subordinated notes due 2021, at par;
- purchased or redeemed $150.0 million principal amount of our 6.375% senior subordinated notes due 2015 at a redemption price of 102.31% and purchased or redeemed $250.0 million principal amount of our 7.5% senior subordinated notes due 2016 at a redemption price of 103.9%;
- spent $22.0 million related to debt issuance costs; and
- recorded a decrease of $39.8 million in cash overdrafts.

During the nine months ended September 30, 2010, we:

- borrowed $784.0 million and repaid $943.0 million under our bank credit facility, ending the period with a $91.0 million lower bank credit facility balance;
- issued $500.0 million principal amount of 6.75% senior subordinated notes due 2020, at par;
- redeemed $200.0 million principal amount of our 7.375% senior subordinated notes due 2013 at a redemption price of 101.229%; and
- recorded an increase of $7.6 million in cash overdrafts.

Credit Arrangements

On September 30, 2011, the bank credit facility had a $2.0 billion borrowing base, a $1.5 billion facility amount and we had no outstanding borrowings. The borrowing base represents an amount approved by the bank group that can be borrowed based on our assets, while our $1.5 billion facility amount is the amount we have requested that the banks commit to fund pursuant to the credit agreement. The bank credit facility provides for a borrowing base subject to redeterminations semi-annually each April and October and for event-driven unscheduled redeterminations. As part of our semi-annual bank review completed October 12, 2011 our borrowing base and facility amounts were reaffirmed at $2.0 billion and $1.5 billion. Remaining credit availability was approximately $1.4 billion on October 21, 2011. Our bank group is comprised of twenty-six commercial banks with no one bank holding more than 7.0% 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 $1.5 billion commitment up to the $2.0 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 4.25 to 1.0 and a current ratio (as defined in the credit agreement) of no less than 1.0 to 1.0. We were in compliance with these covenants at September 30, 2011. See Note 9 to the accompanying consolidated financial statements for additional information.

In May 2011, we issued $500.0 million aggregate principal amount of 5.75% senior subordinated notes due 2021 for net proceeds after underwriting discounts and commissions of $491.3 million. The 5.75% Notes were issued at par. Interest on the 5.75% Notes is payable semi-annually in June and December and is guaranteed by substantially all of our subsidiaries. We may redeem the 5.75% Notes, in whole or in part, at any time on or after June 1, 2016, at redemption prices of 102.875% of the principal amount as of June 1, 2016 declining to 100.0% on June 1, 2019 and thereafter. Before June 2014, we may redeem up to 35% of the original aggregate principal amount of the 5.75% Notes at a redemption price equal to 105.75% of the principal amount thereof, plus accrued and unpaid interest, if any, with the proceeds of certain equity offerings, provided that 65% of the aggregate principal amount of 5.75% Notes remain outstanding immediately after the occurrence of such redemption and also provided such redemption shall occur within 60 days of the date of closing of the equity offering. On closing, we used $112.9 million of the proceeds to redeem our 6.375% senior subordinated notes due 2015 and $207.1 million to redeem our 7.5% senior subordinated notes due 2016 as part of the tender offer described below.

On May 11, 2011, we commenced cash tender offers to purchase the entire outstanding $150.0 million principal amount of our 6.375% senior subordinated notes due 2015 and $250.0 million principal amount of our 7.5% senior subordinated notes due 2016. On May 25, 2011, after the expiration of the tender offers, we accepted for purchase $108.9 million in principal of the 2015 notes at 102.375% of par and $198.8 million in principal of the 2016 notes for 104.00% of par. We called the remaining 2015 and 2016 notes, redeeming all of the remaining outstanding 2015 notes ($41.1 million) at 102.125% of par on June 24, 2011 and redeeming all of the remaining outstanding 2016 notes ($51.2 million) at 103.75% of par on June 24, 2011. During second quarter 2011, we recognized an $18.6 million loss on early extinguishment of debt, including transaction call premium cost as well as expensing of deferred financing cost on repurchased debt.

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

As we pursue our strategy, we may utilize various financing sources, including, to the extent available, fixed and floating rate debt, or common stock. We may also issue securities in exchange for oil and gas properties.

Liquidity

Our principal sources of short-term liquidity are cash on hand and unused borrowing capacity under our bank credit facility. As of September 30, 2011, we had no outstanding borrowings under our credit facility and we were in compliance with all of its debt covenants. After adjusting for $22.2 million of undrawn and outstanding letters of credit, we had approximately $1.5 billion of unused borrowing capacity as of September 30, 2011. Our letter of credit requirements may change based on our financial condition and our debt credit ratings from the major rating agencies.

If internal cash flow and cash on hand do not meet our expectations, we may reduce our level of capital expenditures, and/or fund a portion of our capital expenditures using borrowings under our bank credit facility, issue debt or equity securities or receive cash from other sources, such as asset sales. We cannot provide any assurance that needed short-term or long-term liquidity will be available on acceptable terms or at all. Although we expect that internal operating cash flows, cash on hand and borrowing capacity under our bank credit facility will be adequate to fund capital expenditures and provide adequate liquidity to fund other needs, no assurances can be given that such funding sources will be adequate to meet our future needs. For instance, the amount that we may borrow under the bank credit facility in the future could be reduced as a result of lower oil, NGL or gas prices, among other items.

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

Capital Commitments

Our primary needs for cash are for capital expenditures on natural gas and oil assets, payment of contractual obligations, dividends and working capital obligations. Funding for these cash needs may be provided by any combination of internally- generated cash flow, proceeds from the disposition of assets or external financing sources. We expect we will be able to fund our needs for cash (excluding acquisitions) with internally-generated cash flows, cash on hand and liquidity under our credit facility, although no assurances can be given that such funding will be adequate to meet our future needs. We generally strive to limit our capital expenditures to internally-generated cash flow plus proceeds from asset sales. We establish a capital budget at the beginning of each calendar year. Our 2011 capital budget (excluding acquisitions) now stands at $1.47 billion and focuses on projects we believe will generate and lay the foundation for economic, long-term production growth.

Investing Activities

Net cash used in investing activities of continuing operations for the nine months ended September 30, 2011 was $953.3 million compared to $476.6 million in the same period of 2010. During the nine months ended September 30, 2011, we:

- spent $855.4 million on natural gas and oil property additions;
- spent $151.1 million on acreage primarily in the Marcellus Shale; and
- received proceeds of $66.2 million primarily from the sale of a low pressure pipeline, from the sale of properties in East Texas and Pennsylvania and from the sale of certain hedges as part of our Barnett Shale sale.

During the nine months ended September 30, 2010, we:

- spent $540.5 million on natural gas and oil property additions;
- spent $249.7 million on acreage primarily in the Marcellus Shale; and
- received proceeds of $327.5 million primarily from the sale of our Ohio oil and gas properties.

Dividends

On September 30, 2011, the Board of Directors declared a dividend of four cents per share ($6.4 million) on our common stock, which was paid on September 30, 2011 to stockholders of record at the close of business on September 15, 2011. Future dividends are at the discretion of the Board and, if declared, the Board may change the current dividend amount based on our liquidity and capital resources.

Contractual Obligations

Our contractual obligations include long-term debt, operating leases, drilling commitments, derivative obligations, transportation commitments and other purchase obligations. The table below summarizes our significant contractual obligations as of September 30, 2011 (in thousands).

	Payment due by period					
	Remaining 2011	2012	2013	2014 and 2015	Thereafter	Total
7.5% senior subordinated notes due 2017	$	$	$	$	$ 250,000	$ 250,000
7.25% senior subordinated notes due 2018					250,000	250,000
8.0% senior subordinated notes due 2019					300,000	300,000
6.75% senior subordinated notes due 2020					500,000	500,000
5.75% senior subordinated notes due 2021					500,000	500,000
Operating leases	2,407	11,063	10,055	18,901	28,574	71,000
Drilling rig commitments	11,344	42,777	14,673	895		69,689
Transportation commitments	22,880	91,235	90,588	177,295	510,508	892,506

Other purchase obligations[a]	31,826	119,250	56,090	328	1,626	209,120
Derivative obligations[b]						
Asset retirement obligation liability[c]	4,020	8,984	1,163	4,205	56,744	75,116
Total contractual obligations	$ 72,477	$ 273,309	$ 172,569	$ 201,624	$ 2,397,452	$ 3,117,431

(a) Includes primarily agreements for hydraulic well fracturing services.

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

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

Debt Ratings

We receive debt credit ratings from two of the major rating agencies, which are subject to regular reviews. We believe that each of the rating agencies consider many factors in determining our ratings including: production growth opportunities, liquidity, debt levels, asset composition 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.

Book Capitalization

Our net book capitalization at September 30, 2011 was $4.1 billion, consisting of $51.9 million of cash and cash equivalents, debt of $1.8 billion and stockholder s equity of $2.3 billion. Our net debt to net book capitalization was 42.7% at September 30, 2011 and 46.9% at December 31, 2010.

Capital Requirements

We currently estimate our 2011 capital spending will approximate $1.47 billion (excluding acquisitions) and based on current projections is expected to be funded with internal cash flow, property sales and our bank credit facility. Acreage purchases during the first nine months include $113.8 million of purchases in the Marcellus Shale, which were funded with borrowings under our bank credit facility and asset sales. For the nine months ended September 30, 2011, $957.2 million of our development and exploration spending was funded with internal cash flow, borrowings under our bank credit facility and 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, divestitures and continued growth. We may choose to sell assets, issue subordinated notes or other debt securities, or issue additional shares of stock to fund capital expenditures or acquisitions, extend maturities or repay debt.

Other Contingencies

We are involved in various legal actions, claims and other regulatory proceedings arising in the ordinary course of our business. While the outcome of these lawsuits cannot be predicted with certainty, we believe the resolution of these proceedings will not have a material adverse effect on our liquidity or consolidated financial position. If an unfavorable ruling were to occur, there exists the possibility of a material adverse impact on our net income or loss in the period in which the ruling occurs.

Hedging Natural Gas and Oil Prices

We use commodity-based derivative contracts to manage exposure to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. Historically, these contracts consisted of collars and fixed price swaps. We do not utilize complex derivatives such as swaptions, knockouts or extendable swaps. Reducing our exposure to price volatility helps ensure that we have adequate funds available for our capital program. Our decision on the quantity and price at which we choose to hedge our future production is based in part on our view of current and future market conditions. In light of current worldwide economic uncertainties, we have employed a strategy to hedge a portion of our production looking out 12 to 36 months from each quarter. At September 30, 2011, we had open swap contracts covering 25.6 Bcf of natural gas at prices averaging $5.00 and 2.5 million barrels of NGLs (the C5 component) at an average price of $103.00 per barrel. At September 30, 2011, we had collars covering 159.8 Bcf of natural gas at weighted average floor and cap prices of $5.24 and $5.87 per mcf and 0.7 million barrels of oil at weighted average floor and cap prices of $70.00 and $80.00 per barrel. At September 30, 2011, we also had sold call options covering 2.2 million barrels of oil at a weighted average price of $83.86. At the time of settlement of these monthly call options, if the market price exceeds the fixed price of the call option, we will pay the counterparty such excess and if the market settles below the fixed price of the call option, no payment is due from either party. The fair value of all of our derivative contracts, represented by the estimated amount that would be realized upon termination, based on a comparison of contract prices and a reference price, generally NYMEX, on September 30, 2011 was a net unrealized pre-tax gain of $183.6 million. The contracts expire monthly through December 2013. Settled transaction gains and losses for derivatives that qualify for hedge accounting are determined monthly and are included as increases or decreases in natural gas, NGLs and oil sales in the period the hedged production is sold. In the first nine months of 2011, natural gas, NGLs and oil sales included realized hedging gains of $80.7 million compared to gains of $35.2 million in the same period of 2010.

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At September 30, 2011, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Average Hedge Price	
Natural Gas				
2012	Swaps	70,000 Mmbtu/day	$5.00	
2011	Collars	348,200 Mmbtu/day	$5.33	$6.18
2012	Collars	189,641 Mmbtu/day	$5.32	$5.91
2013	Collars	160,000 Mmbtu/day	$5.09	$5.65
Crude Oil				
2012	Collars	2,000 bbls/day	$70.00	$80.00
2011	Call options	5,500 bbls/day	$80.00	
2012	Call options	4,700 bbls/day	$85.00	
NGLs				
2011	Swaps	7,000 bbls/day	$104.17	
2012	Swaps	5,000 bbls/day	$102.59	

Some of our derivatives do not qualify for hedge accounting or are not designated as a hedge but provide an economic hedge of our exposure to commodity price risk associated with anticipated future natural gas and oil production. These contracts are accounted for using the mark-to-market accounting method. Under this method, the contracts are carried at their fair value as unrealized derivative gains and losses in the accompanying consolidated balance sheets. We recognize all unrealized and realized gains and losses related to these contracts as derivative fair value income or loss in our consolidated statements of operations. As of September 30, 2011, derivatives on 37.2 Bcfe no longer qualify or are not designated for hedge accounting.

Interest Rates

At September 30, 2011, we had $1.8 billion of debt outstanding which bears interest at fixed rates averaging 6.9%.

Inflation and Changes in Prices

Our revenues, the value of our assets and our ability to obtain bank loans or additional capital on attractive terms have been, and will continue to be affected by changes in natural gas and oil prices and the costs to produce our reserves. Natural gas and oil prices are subject to fluctuations that are beyond our ability to control or predict. During third quarter 2011, we received an average of $3.61 per mcf of gas and $81.18 per barrel of oil before derivative contracts compared to $3.86 per mcf of gas and $66.74 per barrel of oil in the same period of the prior year. Although certain of our costs are affected by general inflation, inflation does not normally have a significant effect on our business. In a trend that began in 2004 and accelerated through the middle of 2008, commodity prices for oil and gas increased significantly. The higher prices led to increased activity in the industry and, consequently, rising costs. These cost trends put pressure not only on our operating costs but also on capital costs. Due to the decline in commodity prices since then, costs have generally moderated but are increasing in areas with high levels of drilling activity that utilize specialized services for horizontal drilling and completions. We expect costs in 2011 and 2012 to continue to be a function of supply and demand.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Market Risk

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

Commodity Price Risk

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

As of September 30, 2011, we had swaps covering 25.6 Bcf of natural gas and 2.5 million barrels of NGLs, collars covering 159.8 Bcf of natural gas and 0.7 million barrels of oil and call options for 2.2 million barrels of oil. These contracts expire monthly through December 2013. The fair value, represented by the estimated amount that would be realized upon immediate liquidation as of September 30, 2011, approximated a net unrealized pre-tax gain of $183.6 million.

We expect our NGL production to continue to increase. In the first nine months 2011, we entered into NGL swap contracts for the natural gasoline component (C5) of NGLs. In our Marcellus Shale operations, propane is a large product component of our NGL production and we believe NGL prices are somewhat seasonal. Therefore, the percentage of NGL prices to NYMEX WTI (or West Texas Intermediate) will vary due to product components, seasonality and geographic supply and demand.

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At September 30, 2011, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Average Hedge Price	Fair Market Value as of September 30, 2011 Asset (Liability) (in thousands)
Natural Gas				
2012	Swaps	70,000 Mmbtu/day	$5.00	$ 19,304
2011	Collars	348,200 Mmbtu/day	$5.33 $6.18	$ 48,376
2012	Collars	189,641 Mmbtu/day	$5.32 $5.91	$ 77,664
2013	Collars	160,000 Mmbtu/day	$5.09 $5.65	$ 26,461
Crude Oil				
2012	Collars	2,000 bbls/day	$70.00 $80.00	$ (4,340)
2011	Call options	5,500 bbls/day	$80.00	$ (2,945)
2012	Call options	4,700 bbls/day	$85.00	$ (17,792)
NGLs				
2011	Swaps	7,000 bbls/day	$104.17	$ 8,186
2012	Swaps	5,000 bbls/day	$102.59	$ 28,695

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. We currently have not entered into any basis derivatives.

The following table shows the fair value of our swaps, collars and call options and the hypothetical change in the fair value that would result from a 10% and a 25% change in commodity prices at September 30, 2011 (in thousands):

		Hypothetical Change in Fair Value Increase of		Hypothetical Change in Fair Value Decrease of	
	Fair Value	10%	25%	10%	25%
Swaps	$ 56,185	$ (32,340)	$ (80,720)	$ 32,335	$ 80,840
Collars	148,161	(67,327)	(164,444)	68,901	175,182
Call options	(20,737)	(10,419)	(29,456)	8,094	15,824

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Form 10-Q. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of September 30, 2011 at the reasonable assurance level.

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Changes in Internal Control over Financial Reporting

There was no change in our system of internal control over financial reporting (as defined in Rules 13a-15(f) and 15-d-15(f) under the Exchange Act) during the quarter ended September 30, 2011 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II OTHER INFORMATION

ITEM 1A. RISK FACTORS

We are subject to various risks and uncertainties in the course of our business. In addition to the factors discussed elsewhere in this report, you should carefully consider the risks and uncertainties described under Item 1A. Risk Factors filed in our Annual Report on Form 10-K for the year ended December 31, 2010. There have been no material changes from the risk factors previously disclosed in that Form 10-K.

ITEM 6. EXHIBITS
(a) EXHIBITS

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

* filed herewith

** furnished herewith

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SIGNATURES

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

Date: October 25, 2011

RANGE RESOURCES CORPORATION

By: /s/ ROGER S. MANNY
Roger S. Manny
Executive Vice President and Chief Financial Officer

Date: October 25, 2011

RANGE RESOURCES CORPORATION

By: /s/ DORI A. GINN
Dori A. Ginn
Principal Accounting Officer and Vice President Controller

Exhibit index

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