RANGE RESOURCES CORP
Form 10-Q
October 25, 2007

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

(Mark one)

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

For the quarterly period ended September 30, 2007

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 is a large accelerated filer, an accelerated filer or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer þ Accelerated Filer o Non-Accelerated Filer 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

149,193,657 Common Shares were outstanding on October 22, 2007.

RANGE RESOURCES CORPORATION
FORM 10-Q
Quarter Ended September 30, 2007

Unless the context otherwise indicates, all references in this report to Range we us or our are to Range Resources Corporation and its subsidiaries.

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PART I Financial Information
ITEM 1. Financial Statements

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

	September 30, 2007	December 31, 2006
Assets		
Current assets:		
Cash and equivalents	$ 187	$ 2,382
Accounts receivable, less allowance for doubtful accounts of $459 and $746	146,618	125,421
Assets held for sale		79,304
Assets of discontinued operation		78,161
Unrealized derivative gain	72,153	93,588
Inventory and other	12,102	10,069
Total current assets	231,060	388,925
Unrealized derivative gain	10,590	61,068
Equity method investments	111,735	13,618
Oil and gas properties, successful efforts method	4,286,179	3,359,093
Accumulated depletion and depreciation	(924,155)	(751,005)
	3,362,024	2,608,088
Transportation and field assets	99,256	80,066
Accumulated depreciation and amortization	(40,577)	(32,923)
	58,679	47,143
Other assets	74,338	68,832
Total assets	$ 3,848,426	$ 3,187,674
Liabilities		
Current liabilities:		
Accounts payable	$ 182,483	$ 171,914
Asset retirement obligation	1,251	3,853
Accrued liabilities	40,785	30,026
Liabilities of discontinued operation		28,333
Accrued interest	11,791	12,938
Unrealized derivative loss	7,657	4,621
Total current liabilities	243,967	251,685

Bank debt	266,000	452,000
Subordinated notes	847,062	596,782
Deferred tax, net	562,703	468,643
Unrealized derivative loss	4,967	266
Deferred compensation liability	133,962	90,094
Asset retirement obligation and other liabilities	80,953	72,043
Commitments and contingencies		
Stockholders equity		
Preferred stock, $1 par, 10,000,000 shares authorized, none issued and outstanding		
Common stock, $.01 par, 250,000,000 shares authorized, 148,963,308 issued at September 30, 2007 and 138,931,565 issued at December 31, 2006	1,490	1,389
Common stock held in treasury, 155,500 shares at September 30, 2007, none at December 31, 2006 at cost	(5,334)	
Additional paid-in capital	1,392,441	1,079,994
Retained earnings	343,473	160,313
Common stock held by employee benefit trust, 2,185,898 shares at September 30, 2007 and 1,853,279 shares at December 31, 2006 - at cost	(36,232)	(22,056)
Accumulated other comprehensive income	12,974	36,521
Total stockholders equity	1,708,812	1,256,161
Total liabilities and stockholders equity	$ 3,848,426	$ 3,187,674

See 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,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
Revenues (See Note 2)				
Oil and gas sales	$ 214,424	$ 153,054	$ 621,636	$ 443,143
Transportation and gathering	508	1,015	1,203	1,933
Derivative fair value income	25,002	65,306	10,618	119,914
Other	2,419	250	5,251	3,255
Total revenues	242,353	219,625	638,708	568,245
Costs and expenses				
Direct operating	28,003	22,336	78,233	57,402
Production and ad valorem taxes	11,316	9,874	32,958	27,970
Exploration	6,233	16,508	29,668	33,193
General and administrative	18,058	12,170	50,574	36,014
Deferred compensation plan	7,761	(2,638)	28,342	(347)
Interest expense	19,935	16,389	56,356	38,266
Depletion, depreciation and amortization	57,001	40,606	155,798	106,252
Total costs and expenses	148,307	115,245	431,929	298,750
Income from continuing operations before income taxes	94,046	104,380	206,779	269,495
Income tax provision				
Current	133	615	416	1,815
Deferred	34,802	38,707	73,698	99,533
	34,935	39,322	74,114	101,348
Income from continuing operations	59,111	65,058	132,665	168,147
Discontinued operations, net of income taxes	(196)	(13,728)	63,593	(9,872)
Net income	$ 58,915	$ 51,330	$ 196,258	$ 158,275
Earnings per common share:				
Basic income from continuing operations	$ 0.40	$ 0.47	$ 0.92	$ 1.27
- discontinued operations		(0.10)	0.45	(0.07)

- net income	$	0.40	$	0.37	$	1.37	$	1.20
Diluted income from continuing operations	$	0.39	$	0.46	$	0.89	$	1.22
- discontinued operations				(0.10)		0.43		(0.07)
- net income	$	0.39	$	0.36	$	1.32	$	1.15
Dividends per common share	$	0.03	$	0.02	$	0.09	$	0.06
Weighted average common shares outstanding:								
Basic		147,182		136,983		143,508		132,426
Diluted		152,391		142,022		148,671		137,466

See accompanying notes.

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

	Nine Months Ended September 30, 2007	2006
Operating activities:		
Net income	$ 196,258	$ 158,275
Adjustments to reconcile to net cash provided from operating activities:		
(Gains)/losses from discontinued operations	(63,593)	9,872
(Gains)/losses from equity method investments	(1,280)	61
Deferred income tax expense	73,698	99,533
Depletion, depreciation and amortization	155,798	106,252
Unrealized derivative gains	(502)	(3,178)
Mark-to-market (gains)/losses on oil and gas derivatives not designated as hedges	40,171	(83,734)
Exploration dry hole costs	9,072	9,291
Amortization of deferred issuance costs and other	1,667	1,221
Non-cash compensation	46,770	13,839
Loss on sale of assets and other	2,247	1,009
Changes in working capital, net of amounts from business acquisitions:		
Accounts receivable	(29,595)	29,323
Inventory and other	(1,672)	(1,911)
Accounts payable	11,597	(17,801)
Accrued liabilities and other	4,894	(2,387)
Net cash provided from continuing operations	445,530	319,665
Net cash provided from discontinued operations	10,189	28,475
Net cash provided from operating activities	455,719	348,140
Investing activities:		
Additions to oil and gas properties	(601,046)	(328,362)
Additions to field service assets	(20,318)	(10,033)
Acquisitions, net of cash acquired	(309,660)	(336,735)
Investment in equity method affiliates and other	(93,313)	(21,008)
Purchases of marketable securities held by deferred compensation plan	(34,724)	
Proceeds from sales of marketable securities held by deferred compensation plan	33,823	
Proceeds from disposal of assets	25	166
Proceeds from disposal of discontinued operations	234,304	
Investing activities of discontinued operations	(7,375)	(18,630)
Net cash used in investing activities	(798,284)	(714,602)
Financing activities:		
Borrowings on credit facility	718,000	650,500
Repayments on credit facility	(904,000)	(535,000)

Debt issuance costs	(2,727)	(5,560)
Dividends paid	(13,098)	(8,021)
Issuance of common stock, net	292,753	12,544
Issuance of subordinated notes	250,000	249,500
Proceeds from sales of common stock held by deferred compensation plan and other	4,845	
Purchases of common stock held by deferred compensation plan and other treasury stock purchases	(5,403)	
Net cash provided from financing activities	340,370	363,963
Net decrease in cash and equivalents	(2,195)	(2,499)
Cash and equivalents at beginning of period	2,382	4,750
Cash and equivalents at end of period	$ 187	$ 2,251

See accompanying notes.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Net income	$ 58,915	$ 51,330	$ 196,258	$ 158,275
Net deferred hedge gains/(losses), net of tax:				
Contract settlements reclassified to income	18,337	14,511	(8,863)	50,130
Change in unrealized deferred hedging gains/(losses)	(17,093)	66,692	(16,295)	108,672
Change in unrealized gains on securities held by deferred compensation plan, net of taxes	491	433	1,611	191
Comprehensive income	$ 60,650	$ 132,966	$ 172,711	$ 317,268

See accompanying notes.

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RANGE RESOURCES CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

(1) ORGANIZATION AND NATURE OF BUSINESS

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

(2) BASIS OF PRESENTATION

Certain disclosures have been condensed or omitted from these statements. Therefore, these interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Range Resources Corporation 2006 Annual Report on Form 10-K and our Form 8-K filed on June 19, 2007. 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 for complete financial statements. Certain reclassifications have been made to the presentation of prior periods to conform to the current year presentation, which includes the presentation of our Gulf of Mexico operations as discontinued operations and the reclassification of settled derivatives that do not qualify for hedge accounting from oil and gas sales to derivative fair value income. We previously had been reclassifying the realized gain or loss from non-hedge derivatives into oil and gas sales. This reclassification will now present all gains and losses, realized and unrealized, on the derivative fair value income line in our consolidated statements of operations. These are changes to presentation only and do not affect previously reported net income, total revenues or earnings per share. The following table details the affected financial statement line items related to the revenue reclassification for the periods previously reported, including the six months ended June 30, 2007 and the nine months ended September 30, 2006 (in thousands):

	Three Months Ended March 31, 2007	Three Months Ended June 30, 2007	Six Months Ended June 30, 2007
As reported:			
Oil and gas sales	$ 217,026	$ 221,591	$ 438,617
Mark-to-market on oil and gas derivatives	(66,111)	20,322	(45,789)
	$ 150,915	$ 241,913	$ 392,828
As reclassified:			
Oil and gas sales	$ 193,316	$ 213,896	$ 407,212
Derivative fair value income	(42,401)	28,017	(14,384)
	$ 150,915	$ 241,913	$ 392,828

	Three Months Ended March 31, 2006	Three Months Ended June 30, 2006	Three Months Ended September 30, 2006	Nine Month Ended September 30, 2006
As reported:				

Oil and gas sales	$ 166,555	$ 149,358	$ 163,410	$ 479,323
Mark-to-market on oil and gas derivatives	11,281	17,503	54,950	83,734
	$ 177,836	$ 166,861	$ 218,360	$ 563,057
As reclassified:				
Oil and gas sales	$ 150,658	$ 139,431	$ 153,054	$ 443,143
Derivative fair value income	27,178	27,430	65,306	119,914
	$ 177,836	$ 166,861	$ 218,360	$ 563,057

During the first quarter of 2007, we sold our interests in our Austin Chalk properties that we purchased as part of the Stroud acquisition. We also sold our Gulf of Mexico properties at the end of the first quarter of 2007. In accordance with Statement of Financial Accounting Standards (SFAS) No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, we have reflected the results of operations of the above divestitures as discontinued operations, rather than a component of continuing operations. See Note 4 for additional information regarding discontinued operations.

(3) ACQUISITIONS AND DISPOSITIONS

Acquisitions

In May 2007, we acquired additional interests in the Nora field of Virginia and entered into a joint development plan with Equitable Resources, Inc (Equitable). As a result of this transaction, Equitable and Range equalized their working interests in the Nora field, including producing wells, undrilled acreage and gathering systems. Range retained its separately owned royalty interest in the Nora field. Equitable will operate the producing wells, manage the drilling operations of all future coal bed methane wells and manage the gathering system. Range will oversee the drilling of formations below the coal bed methane formations, including tight gas, shale and deeper formations. A newly formed limited liability corporation will hold the investment in the gathering system which is owned 50% by Equitable and 50% by Range. All business decisions require a unanimous consent of both parties. The gathering system investment is accounted for as an equity method investment. Including estimated transaction costs, we paid $278.6 million which includes $188.3 million allocated to oil and gas properties, $93.4 million allocated to our equity method investment and a $3.1 million asset retirement obligation. No pro forma information has been provided as the acquisition was not considered significant.

In June 2006, we acquired Stroud Energy, Inc. (Stroud), a private oil and gas company with operations in the Barnett Shale in North Texas, the Cotton Valley in East Texas and the Austin Chalk in Central Texas. To acquire Stroud, we paid $171.5 million of cash and issued 6.5 million shares of our common stock.

The following table summarizes the final purchase price allocation to assets acquired and liabilities assumed at closing in the Stroud acquisition (in thousands):

Cash paid (including transaction costs)	$ 171,529
6.5 million shares of common stock (at fair value of $27.26 per share)	177,641
Stock options assumed (652,000 options)	9,478
Debt retired	106,700
Total	$ 465,348
Allocation of purchase price:	
Working capital deficit	$ (13,557)
Other long-term assets	55
Oil and gas properties	487,345
Assets held for sale	140,000
Deferred income taxes	(147,062)
Asset retirement obligation	(1,433)
Total	$ 465,348

Pro Forma

The following unaudited pro forma data includes the results of operations as if the Stroud acquisition had been consummated at the beginning of 2006. See also Note 4 for additional information on discontinued operations. The pro forma data are based on historical information and do not necessarily reflect the actual results that would have occurred, nor are they necessarily indicative of future results of operations (in thousands, except per share data).

	Nine Months Ended September 30, 2006
Revenues	$602,920
Income from continuing operations	167,570
Net income	161,571
Per share data:	
Income from continuing operations basic	$ 1.22
Income from continuing operations diluted	1.18
Net income basic	$ 1.18
Net income diluted	1.14

Dispositions

In February 2007, we sold the Stroud Austin Chalk properties for proceeds of $80.4 million and recorded a loss on the sale of $2.3 million. These properties were originally acquired in mid 2006 as part of our Stroud acquisition and were classified as assets held for sale since the acquisition date. In March 2007, we sold our Gulf of Mexico properties for proceeds of $155.0 million and recorded a gain on the sale of $95.1 million. The properties included any properties within the waters of the Gulf of Mexico (either state or federal). We have reflected the results of operations of the above divestitures as discontinued operations rather than a component of continuing operations. See Note 4 for additional information.

(4) DISCONTINUED OPERATIONS

As part of the Stroud acquisition, we purchased Austin Chalk properties in East Texas which we sold in February 2007 for proceeds of $80.4 million. These Austin Chalk properties were classified as Assets Held for Sale on our balance sheet as of December 31, 2006 and were reflected in discontinued operations in our consolidated statement of operations in the twelve months ended December 31, 2006. In March 2007, we sold our Gulf of Mexico properties for proceeds of $155.0 million. All prior year periods include the reclassification of our Gulf of Mexico operations to discontinued operations.

Discontinued operations for the three months and the nine months ended September 30, 2007 and 2006 are summarized as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Revenues:				
Oil and gas sales	$	$ 18,959	$ 15,187	$ 38,022
Transportation and gathering		19	10	76
Other		(1)	310	(2)
Gain (loss) on disposition of assets and other	(298)		92,757	
	(298)	18,977	108,264	38,096
Costs and expenses:				
Direct operating		2,923	2,559	8,113
Production and ad valorem taxes		409	141	777
Exploration and other	3	179	215	1,349
Interest expense		1,259	845	1,936
Depletion, depreciation and amortization		5,652	6,672	11,406
Impairment		30,362		30,362
	3	40,784	10,432	53,943
Income (loss) from discontinued operations before income taxes	(301)	(21,807)	97,832	(15,847)
Income tax expense (benefit)	(105)	(8,079)	34,239	(5,975)
Income (loss) from discontinued operations, net of taxes	$ (196)	$ (13,728)	$ 63,593	$ (9,872)
Production:				
Crude oil (bbls)		43,323	40,634	100,515
Natural gas (mcf)		2,734,521	1,990,277	5,187,183
Total (mcfe)		2,994,459	2,234,081	5,790,273

Due to falling oil and gas prices since the acquisition, we recognized a $30.4 million impairment on the Austin Chalk properties during the three months ended September 30, 2006. Ultimately, for the twelve months ended December 31, 2006, we recognized an impairment of $74.9 million.

(5) INCOME TAXES

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006

Income tax expense	$34,935	$39,322	$74,114	$101,348
Effective tax rate	37.1%	37.7%	35.8%	37.6%

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 or loss, except for discrete items. Income taxes for discrete items are computed and recorded in the period that the specific transaction occurs. For the three months and nine months ended September 30, 2007, our overall effective tax rate on continuing operations was different than the statutory rate of 35% primarily due to state income taxes and an increase in our deferred tax assets related to state tax credit carryovers. The nine months ended September 30, 2007 includes a $3.0 million non-recurring tax benefit related to an increase in the Texas margin tax carryforward. For the three months and nine months ended September 30, 2006, our overall effective tax rate on continuing operations was different than the statutory rate of 35% due primarily to state income taxes. We expect our effective tax rate to be approximately 37% for the remainder of 2007.

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At December 31, 2006, we had regular tax net operating loss (NOL) carryovers of $216.4 million and alternative minimum tax (AMT) NOL carryovers of $173.4 million that expire between 2012 and 2026. Even with the gain recognized on the sale of our Gulf of Mexico assets, we expect our NOL carryovers to increase in 2007 due to the current deduction of intangible drilling costs for tax purposes. Our deferred tax asset related to regular NOL carryovers at December 31, 2006 was $51.6 million, net of the SFAS No. 123(R) deduction for unrealized excess tax benefits. At December 31, 2006, we had AMT credit carryovers of $777,000 that are not subject to limitation or expiration.

(6) EARNINGS PER COMMON SHARE

The following table sets forth the computation of basic and diluted earnings per common share (in thousands except per share amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Numerator:				
Income from continuing operations	$ 59,111	$ 65,058	$ 132,665	$ 168,147
Income (loss) from discontinued operations, net of taxes	(196)	(13,728)	63,593	(9,872)
Net income	$ 58,915	$ 51,330	$ 196,258	$ 158,275
Denominator:				
Weighted average shares outstanding	148,586	138,318	144,705	133,767
Stock held in the deferred compensation plan and treasury stock	(1,404)	(1,335)	(1,197)	(1,341)
Weighted average shares, basic	147,182	136,983	143,508	132,426
Effect of dilutive securities:				
Weighted average shares outstanding	148,586	138,318	144,705	133,767
Employee stock options, SARs and other	3,883	3,704	3,992	3,699
Treasury shares	(78)		(26)	
Dilutive potential common shares for diluted earnings per share	152,391	142,022	148,671	137,466
Earnings per common share basic and diluted:				
Basic income from continuing operations	$ 0.40	$ 0.47	$ 0.92	$ 1.27
discontinued operations		(0.10)	0.45	(0.07)
net income	$ 0.40	$ 0.37	$ 1.37	$ 1.20
Diluted income from continuing operations	$ 0.39	$ 0.46	$ 0.89	$ 1.22
discontinued operations		(0.10)	0.43	(0.07)

net income	$ 0.39	$ 0.36	$ 1.32	$ 1.15

Stock appreciation rights for 544,133 and 281,597 shares were outstanding but not included in the computations of diluted net income per share for the three months and the nine months ended September 30, 2007 because the grant prices of the SARs were greater than the average market price of the common shares and would be anti-dilutive to the computations. Stock appreciation rights for 48,000 and 18,000 shares were outstanding but not included in the computations of diluted net income per share for the three months and the nine months ended September 30, 2006 because the grant price of the SARs was greater than the average price of the common shares and would be anti-dilutive to the computations.

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(7) SUSPENDED EXPLORATORY WELL COSTS

The following table reflects the changes in capitalized exploratory well costs for the nine months ended September 30, 2007 and the year ended December 31, 2006 (in thousands):

	September 30, 2007	December 31, 2006
Beginning balance at January 1	$ 9,984	$ 25,340
Additions to capitalized exploratory well costs pending the determination of proved reserves	12,861	4,695
Reclassifications to wells and equipment based on determination of proved reserves	(3,430)	(16,710)
Capitalized exploratory well costs charged to expense	(8,225)	(3,341)
Divested wells	(1,325)	
Balance at end of period	9,865	9,984
Less exploratory well costs that have been capitalized for a period of one year or less	(8,828)	(4,792)
Capitalized exploratory well costs that have been capitalized for a period greater than one year	$ 1,037	$ 5,192
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	2	3

The $9.9 million of capitalized exploratory well costs at September 30, 2007 was incurred in 2007 ($6.9 million) and in 2006 ($3.0 million). As of September 30, 2007, of the $1.0 million of exploratory costs that have been capitalized for more than one year, one of the wells is not operated by us and the other well has been delayed due to rig availability.

(8) INDEBTEDNESS

We had the following debt outstanding as of the dates shown below (in thousands) (bank debt interest rate at September 30, 2007 is shown parenthetically). No interest expense was capitalized during the three months or the nine months ended September 30, 2007 and 2006.

	September 30, 2007	December 31, 2006
Bank debt (6.3%)	$ 266,000	$ 452,000
Subordinated debt:		
7.375% Senior Subordinated Notes due 2013, net of discount	197,515	197,262
6.375% Senior Subordinated Notes due 2015	150,000	150,000
7.5% Senior Subordinated Notes due 2016, net of discount	249,547	249,520
7.5% Senior Subordinated Notes due 2017	250,000	
Total debt	$ 1,113,062	$ 1,048,782

Bank Debt

In October 2006, we entered into an amended and restated revolving bank facility, which we refer to as our bank debt or bank credit facility, which is secured by substantially all of our assets. The bank credit facility provides for an initial commitment equal to the lesser of a facility amount or the borrowing base. On September 30, 2007, the facility amount was $900.0 million. On October 22, 2007, the borrowing base was redetermined to be $1.5 billion and the maturity date was extended to October 25, 2012. The bank credit facility provides for a borrowing base subject to redeterminations semi annually each April and October and pursuant to certain unscheduled redeterminations. Redeterminations other than increases require approval of 75% of the lenders, while increases require unanimous approval. Subject to certain conditions, the facility amount may be increased to the borrowing base amount with twenty days notice. At September 30, 2007, the outstanding balance under the bank credit facility was $266.0 million and there was $634.0 million of borrowing capacity available. Borrowing under the bank credit facility can either be base rate loans or LIBOR loans. On all base rate loans, the rate per annum is equal to the lesser of (i) the maximum rate (the weekly ceiling as defined in Section 303 of the Texas Finance Code or other applicable laws if greater) (the Maximum Rate) or, (ii) the sum of the higher of (1) the prime rate for such date, or (2) the sum of the federal funds effective rate for such date plus one half of one percent (0.50%) per annum, plus a base rate margin of between 0.0% to 0.5% per annum depending on the total outstanding under the bank credit facility relative to the borrowing base. On all LIBOR loans, we pay a varying rate per annum equal to the lesser of (i) the Maximum Rate, or (ii) the sum of the quotient of (A) the LIBOR base rate, divided by (B) one minus the reserve requirement applicable to such interest period, plus a LIBOR margin of between 1.0% and 1.75% per annum depending on the total outstanding under the bank credit facility 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 6.5% for the three months ended September 30, 2007 compared to 6.7% for the three months ended September 30, 2006. The weighted average interest rate on the bank credit facility was 6.5% for the nine months ended September 30, 2007 compared to 6.3% for the same period of 2006. A commitment fee is paid on the undrawn balance based on an annual rate of between 0.25% and 0.375%. At September 30, 2007, the commitment fee was 0.25% and the interest rate margin was 1.0%. On October 22, 2007, the interest rate on the bank credit facility (including applicable margin) was 6.2%.

Senior Subordinated Notes

In 2003, we issued $100.0 million principal amount of 7.375% senior subordinated notes due 2013 (7.375% Notes). In 2004, we issued an additional $100.0 million of 7.375% Notes; therefore, $200.0 million of the 7.375% Notes is currently outstanding. In 2005, we issued $150.0 million principal amount of 6.375% senior subordinated notes due 2015 (6.375% Notes). In May 2006, we issued $150.0 million principal amount of the 7.5% senior subordinated notes due 2016 (7.5% Notes due 2016). In August 2006, we issued an additional $100.0 million of the 7.5% Notes due 2016; therefore, $250.0 million of the 7.5% Notes due 2016 is currently outstanding. On September 28, 2007, we issued $250.0 million principal amount of 7.5% senior subordinated notes due 2017 (7.5% Notes due 2017). Interest on our senior subordinated notes is payable semi annually, at varying times, and each of the notes is guaranteed by certain of our subsidiaries.

We may redeem the 7.375% Notes, in whole or in part, at any time on or after July 15, 2008, at redemption prices of 103.7% of the principal amount as of July 15, 2008, and declining to 100.0% on July 15, 2011 and thereafter. We may redeem the 6.375% Notes, in whole or in part, at any time on or after March 15, 2010, at redemption prices from 103.2% of the principal amount as of March 15, 2010 and declining to 100% on March 15, 2013 and thereafter. Prior to March 15, 2008, we may redeem up to 35% of the original aggregate principal amount of the 6.375% Notes at a redemption price of 106.4% of the principal amount thereof plus accrued and unpaid interest, if any, with the proceeds of certain equity offerings. We may redeem the 7.5% Notes due 2016, in whole or in part, at any time on or after May 15, 2011 at redemption prices from 103.75% of the principal amount as of May 15, 2011 and declining to 100% on May 15, 2014 and thereafter. Prior to May 15, 2009, we may redeem up to 35% of the original aggregate principal amount of the 7.5% Notes due 2016 at a redemption price of 107.5% of principal amount thereof plus accrued and unpaid interest if any, with the proceeds of certain equity offerings provided that at least 65% of the original aggregate principal amount of our 7.5% Notes due 2016 remains outstanding immediately after the occurrence of such redemption and provided that such redemption occurs within 60 days of the date of closing the equity sale. We may redeem the 7.5% Notes due 2017, in whole or in part, at any time on or after October 1, 2012 at redemption prices from 103.75% of the principal amount as of October 1, 2012 and declining to 100% on October 1, 2015 and thereafter. Prior to October 1, 2010, we may redeem up to 35% of the original aggregate principal amount of the 7.5% Notes due 2017 at a redemption price of 107.5% of principal amount thereof plus accrued and unpaid interest, if any, with the proceeds of certain equity offerings provided that at least 65% of the original aggregate principal amount of our 7.5% Notes due 2017 remains outstanding immediately after the occurrence of such redemption and provided that such redemption occurs within 60 days of the date of closing the equity sale.

If we experience a change of control, there may be a requirement to repurchase all or a portion of the senior subordinated notes at 101% of the principal amount plus accrued and unpaid interest, if any. All of the senior subordinated notes and the guarantees by our subsidiary guarantors are general unsecured obligations and are subordinated to our bank debt and will be subordinated to future senior debt that we or our subsidiary guarantors are permitted to incur under the bank credit facility and the indentures governing the senior subordinated notes.

Subsidiary Guarantors

Range Resources Corporation is a holding company which owns no operating assets and has no significant operations independent of its subsidiaries. The guarantees of the 7.375% Notes, the 6.375% Notes, the 7.5% Notes due 2016 and the 7.5% Notes due 2017 are full and unconditional and joint and several; any subsidiaries other than the subsidiary guarantors are minor subsidiaries.

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Debt Covenants

The debt agreements contain covenants relating to working capital, dividends and financial ratios. We were in compliance with all covenants at September 30, 2007. Under the bank credit facility, dividends are permitted, subject to the provisions of the restricted payment basket. The bank credit facility provides for a restricted payment basket of $20.0 million plus 50% of net income and 66 2/3% of net cash proceeds from common stock issuances. Approximately $726.4 million was available under the bank credit facility s restricted payment basket on September 30, 2007. The terms of each of our subordinated notes limit restricted payments (including dividends) to the greater of $20.0 million or a formula based on earnings and equity issuances since the original issuance of the notes. The 7.5% Notes due 2016 also allows for any cash proceeds received from the sale of oil and gas property purchased in the Stroud acquisition to be added to the restricted payment basket. At September 30, 2007, $900.8 million was available under the restricted payment baskets for each of the 7.375% Notes, 6.375% Notes and the 7.5% Notes due 2017. There was $981.8 million available under the restricted payment basket for the 7.5% Notes due 2016.

(9) ASSET RETIREMENT OBLIGATION

A reconciliation of our liability for plugging and abandonment costs, including discontinued operations, for the nine months ended September 30, 2007 and 2006 is as follows (in thousands):

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Beginning of period	$ 95,588	$ 68,063
Liabilities incurred	3,004	3,150
Acquisitions	3,091	1,433
Liabilities settled	(1,056)	(2,973)
Disposition of wells	(20,850)	
Accretion expense continuing operations	3,843	2,307
Accretion expense discontinued operations	382	1,119
Change in estimate	(3,442)	3,634
End of period	$ 80,560	$ 76,733

Accretion expense is included as a component of depreciation, depletion and amortization.

(10) CAPITAL STOCK

We have authorized capital stock of 260 million shares, which includes 250 million shares of common stock and 10 million shares of preferred stock. The following is a schedule of changes in the number of common shares issued:

	Nine Months Ended September 30, 2007	Year Ended December 31, 2006
Beginning of period	138,931,565	129,913,046
Equity offering	8,050,000	
Shares issued for Stroud acquisition		6,517,498
Stock options/SARs exercised	1,544,193	1,956,164
Restricted stock grants	394,497	474,609
Deferred compensation plan	13,570	12,998
In lieu of bonuses	29,483	20,686

Contributed to 401(k) plan		36,564
	10,031,743	9,018,519
End of period	148,963,308	138,931,565

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Treasury Stock

The Board of Directors has approved up to $10.0 million of repurchases of common stock based on market conditions and opportunities. In the third quarter of 2007, we bought in open market purchases, 155,500 shares at an average price of $34.30. We intend to use such treasury shares for our compensation arrangements to reduce dilution to stockholders.

(11) DERIVATIVE ACTIVITIES

At September 30, 2007, we had open swap contracts covering 73.9 Bcf of gas at prices averaging $8.99 per mcf. We also had collars covering 29.2 Bcf of gas at weighted average floor and cap prices which range from $7.68 to $10.94 per mcf, and 7.0 million barrels of oil at weighted average floor and cap prices that range from $61.11 to $74.99 per barrel. Their fair value, represented by the estimated amount that would be realized upon termination, based on a comparison of the contract prices and a reference price, generally New York Mercantile Exchange (NYMEX), on September 30, 2007, was a net unrealized pre-tax gain of $68.9 million. These contracts expire monthly through December 2009.

Settled transaction gains and losses for derivatives that qualify for hedge accounting are determined monthly and are included as increases or decreases to oil and gas sales in the period the hedged production is sold. Oil and gas sales were increased by realized gains of $4.1 million in the third quarter of 2007 compared to realized losses of $23.0 million in the third quarter of 2006. Oil and gas sales were increased by realized gains of $14.1 million in the first nine months of 2007 compared with realized losses of $79.6 million in the first nine months of 2006. Other revenues in our consolidated statement of operations include ineffective hedging gains on hedges that qualified for hedge accounting of $502,000 in the first nine months of 2007 compared with gains of $3.5 million in the first nine months of 2006.

In the fourth quarter of 2005, certain of our gas hedges no longer qualified for hedge accounting due to the effect of gas price volatility on the correlation between realized prices and hedge reference prices. Also, as a result of the sale of our Gulf of Mexico assets in the first quarter of 2007, a portion of the derivatives which were designated to our Gulf Coast production is now being marked to market. These derivatives have been retained to serve as economic hedges for our production even though we can no longer apply hedge accounting.

The following table sets forth our natural gas and oil derivative volumes by year as of September 30, 2007:

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price
Natural Gas			
2007 4th quarter	Swaps	107,500 Mmbtu/day	$9.49
2007 4th quarter	Collars	98,500 Mmbtu/day	$7.12 $9.93
2008	Swaps	135,000 Mmbtu/day	$9.11
2008	Collars	55,000 Mmbtu/day	$7.93 $11.40
2009	Swaps	40,000 Mmbtu/day	8.24
Crude Oil			
2007 4th quarter	Collars	8,300 bbl/day	$57.69 $68.98
2008	Collars	9,000 bbl/day	$59.34 $75.48
2009	Collars	8,000 bbl/day	$64.01 $76.00

During the third quarter of 2007, in addition to the swaps and collars above, we entered into basis swap agreements which do not qualify as hedges for hedge accounting purposes and are marked to market. The price we receive for our gas production can be less then NYMEX price because of adjustments for delivery location (basis), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively fix our basis adjustments. The fair value of the basis swaps was a net realized pre-tax gain of $1.3 million at September 30, 2007.

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Prior to July 1, 2007, we had been reclassifying the realized gain and loss from non-hedge derivatives into oil and gas sales. Effective July 1, 2007, we have retroactively reclassified the realized gains and losses from non-hedge derivatives to the line derivative fair value income. Thus, all gains and losses realized and unrealized from non-hedge derivatives are now presented as derivative fair value income. The following is a summary of derivative fair value income included in our consolidated statements of operations (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Change in unrealized mark-to-market on oil and gas derivative contracts not designated as hedges	$ 5,618	$ 54,950	$ (40,171)	$ 83,734
Cash receipts realized on settlements of non-hedge contracts gas[a]	19,417	10,356	50,818	36,180
Cash payments realized on settlements of non-hedge contracts oil[a]	(33)		(29)	
Derivative fair value income	$ 25,002	$ 65,306	$ 10,618	$ 119,914

[a] These amounts represent the realized gains and losses on settled non-hedge derivative, which prior to settlement have been recognized as unrealized mark-to-market gains and losses within derivative fair value income.

The combined fair values of derivatives included in the consolidated balance sheets at September 30, 2007 and December 31, 2006 are summarized below. Hedging activities are conducted with major financial and commodities trading institutions which we believe are acceptable credit risks. At times, such risks may be concentrated with certain counterparties. We have master netting agreements with our counterparties. The creditworthiness of the counterparties is subject to continuing review.

	September 30, 2007	December 31, 2006
Derivative assets:		
Natural gas swaps	$ 78,559	$ 121,792
collars	17,478	36,973
basis swaps	937	
Crude oil collars	(14,231)	(4,109)

	$ 82,743	$ 154,656
Derivative liabilities:		
Natural gas swaps	(810)	248
collars	(1,929)	(2,337)
basis swaps	(316)	
Crude oil collars	15,679	6,976
	$ 12,624	$ 4,887

(12) EMPLOYEE BENEFIT AND EQUITY PLANS

We have six equity-based stock plans, of which two are active. Under the active plans, incentive and non-qualified options, stock appreciation rights (SARs), restricted stock awards, phantom stock rights and annual cash incentive awards may be issued to directors and employees pursuant to decisions of the Compensation Committee which is made up of independent directors from the Board of Directors. All awards granted have been issued at prevailing market prices at the time of the grant. During 2007 and 2006, the only type of award issued under our two active plans has been SARs to reduce the dilutive impact of our equity plans. Information with respect to stock option and SARs activities is summarized below:

	Shares	Weighted Average Exercise Price
Outstanding on December 31, 2006	8,852,126	$ 12.76
Granted	1,667,143	33.71
Exercised	(1,754,643)	10.74
Expired/forfeited	(293,865)	23.32
Outstanding on September 30, 2007	8,470,761	$ 16.94

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The following table shows information with respect to outstanding stock options and SARs at September 30, 2007:

Range of Exercise Prices		Outstanding Shares	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Exercisable Shares	Weighted-Average Exercise Price
$ 1.29	$ 9.99	2,961,039	2.19	$ 4.71	2,961,039	$ 4.71
10.00	19.99	2,425,931	2.64	16.21	1,407,814	15.84
20.00	29.99	1,498,823	3.49	24.44	443,390	24.38
30.00	39.99	1,580,568	4.48	33.80	44,100	38.02
40.00	41.01	4,400	4.81	40.66		
Total		8,470,761	2.98	$ 16.94	4,856,343	$ 10.03

The weighted average fair value of a SAR to purchase one share of common stock granted during 2007 was $10.64. The fair value of each SAR granted during 2007 was estimated as of the date of grant using the Black-Scholes-Merton option pricing model based on the following weighted average assumptions: risk-free interest rate of 4.74%, dividend yield of 0.36%, expected volatility of 35.66% and an expected life of 3.54 years.

As of September 30, 2007, the aggregate intrinsic value (the difference in value between exercise and market price) of all awards outstanding was $200.9 million. The aggregate intrinsic value and weighted average remaining contractual life of awards currently exercisable was $148.7 million and 2.48 years, respectively. As of September 30, 2007, the number of fully-vested awards and awards expected to vest was 8.3 million shares. The weighted average exercise price and weighted average remaining contractual life of these awards were $16.65 and 2.95 years, respectively, and the aggregate intrinsic value was $198.8 million. As of September 30, 2007, unrecognized compensation cost related to the awards was $21.2 million, which is expected to be recognized over a weighted average period of 1.08 years. Of the total outstanding awards at September 30, 2007, 4.3 million stock options are outstanding with a weighted-average exercise price of $7.93 and 4.2 million SARs are outstanding with a weighted average grant price of $26.36.

Restricted Stock Grants

During the first nine months of 2007, 429,100 shares of restricted stock were issued to directors and employees as compensation at an average price of $34.75. The grants to directors are immediately vested while the employee grants have a three-year vesting period. In the first nine months of 2006, we issued 476,200 shares of restricted stock as compensation to directors and employees at an average price of $24.32. We recorded compensation expense related to restricted stock grants which is based upon the market value of the shares on the date of grant of $2.3 million in the third quarter of 2007 compared to $1.3 million in the same quarter of the prior year. We recorded compensation expense related to restricted stock grants of $6.4 million in the first nine months of 2007 compared to $2.8 million in the same period of 2006. All restricted shares are granted in lieu of cash awards and are placed in the deferred compensation plan (see below). As of September 30, 2007, unrecognized compensation cost related to these restricted stock awards was $20.8 million, which is expected to be recognized over the next 3 years.

Deferred Compensation Plan

In December 2004, we adopted the Range Resources Corporation Deferred Compensation Plan (2005 Deferred Compensation Plan). The 2005 Deferred Compensation Plan gives directors, officers and key employees the ability to defer all or a portion of their salaries and bonuses and invests such amounts in Range common stock or makes other investments at the individual s discretion. The assets of the plan are held in a rabbi trust, which we refer to as the Rabbi Trust, and are therefore available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. Our stock held in the Rabbi Trust is treated in a manner similar to treasury stock with an offsetting amount reflected as a deferred compensation liability and the carrying value of the deferred compensation liability is adjusted to fair value each reporting period by a charge or credit to deferred compensation plan expense on our consolidated statement of operations. The assets of the Rabbi Trust, other than Range common stock, are invested in marketable securities and reported at market value in other assets on our consolidated balance sheet. The deferred compensation liability on our balance sheet reflects the market value of the securities held in the Rabbi Trust. The cost of common stock held in the Rabbi Trust is shown as a reduction to stockholders equity. Changes in the market value of the marketable securities are reflected in other comprehensive income (OCI), while changes in the market value of the Range common stock held in the Rabbi Trust are charged or credited to deferred compensation plan expense each quarter. We recorded non-cash mark-to-market expense related to our deferred

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compensation plan of $7.8 million in the third quarter of 2007 compared to income of $2.6 million in the third quarter of 2006. We recorded non-cash mark-to-market expense related to our deferred compensation plan of $28.3 million in the first nine months of 2007 compared to income of $348,000 in the first nine months of 2006.

(13) SUPPLEMENTAL CASH FLOW INFORMATION

	Nine Months Ended September 30,	
	2007	2006
	(in thousands)	
Non-cash investing and financing activities included:		
Common stock issued under compensation arrangements	$ 7,660	$ 3,679
Asset retirement costs capitalized	(438)	6,765
Common stock issued for Stroud purchase		177,641
Stock options assumed in Stroud acquisition		9,478
Net cash provided from operating activities included:		
Income taxes paid	$ 144	$ 86
Interest paid	56,657	39,168

(14) COMMITMENTS AND CONTINGENCIES

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

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

	September 30, 2007	December 31, 2006
	(in thousands)	
Oil and gas properties:		
Properties subject to depletion	$ 4,021,173	$ 3,132,830
Unproved properties	265,006	226,263
Total	4,286,179	3,359,093
Accumulated depreciation, depletion and amortization	(924,155)	(751,005)
Net capitalized costs	$ 3,362,024	$ 2,608,088

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

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

	Nine Months Ended September 30, 2007	Year Ended December 31, 2006
	(in thousands)	
Acquisitions:		
Unproved leasehold	$ 4,552	$ 132,821
Proved oil and gas properties	246,264	209,262
Purchase price adjustment [b]		147,062
Asset retirement obligation	3,091	896
Acreage purchases	59,477	79,762
Development	549,786	464,586
Exploration [c]	66,402	70,870
Gas gathering facilities	13,808	19,690
Subtotal	943,380	1,124,949
Asset retirement obligation	(438)	25,821
Total costs incurred [d]	$ 942,942	$ 1,150,770

(a) Includes costs incurred whether capitalized or expensed.

(b) Represents non-cash gross up to account for difference in book and tax basis.

(c) Includes $29.7 million of exploration costs expensed in the nine months ended

September 30, 2007 and $45.3 million of exploration costs expensed in the year ended December 31, 2006. Exploration expense includes $2.6 million of stock-based compensation in the nine months ended September 30, 2007 and $3.1 million of stock-based compensation in the year ended December 31, 2006.

(d) The year ended December 31, 2006, includes $21.5 million related to our divested Gulf of Mexico properties.

(17) NEW ACCOUNTING STANDARD

In June 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes (FIN 48). FIN 48 is an interpretation of FASB Statement No. 109, Accounting for Income Taxes, and seeks to reduce the diversity in practice associated with certain aspects of measurement and recognition in accounting for income taxes. In addition, FIN 48 provides guidance on de-recognition, classification, interest and penalties, and accounting in interim periods and requires expanded disclosure with respect to the uncertainty in income taxes. We adopted the provisions of FIN 48 on January 1, 2007. There was no cumulative effect as a result of applying FIN 48. No adjustment was made to our opening balance of retained earnings. We have approximately $600,000 of unrecognized tax benefits recorded as of the date of adoption.

We file consolidated tax returns in the United States federal jurisdiction and separate income tax returns in many state jurisdictions. We are subject to U.S. Federal income tax examinations for years after 2002 and we are subject to various state tax examinations for years after 2001.

Our continuing practice is to recognize interest related to income tax expense in interest expense, and penalties in general and administrative expense. We do not have any accrued interest or penalties as of September 30, 2007.

(18) ACCOUNTING STANDARDS NOT YET ADOPTED

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. SFAS No. 157 standardizes the definition of fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures related to the use of fair value measures in financial statements. SFAS No. 157 applies whenever other standards require (or permit) assets or liabilities to be measured at fair value but does not expand the use of fair value measurements. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. We do not expect the implementation of SFAS 157 to have a material impact on our results of operations or financial condition.

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In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities including an amendment of FASB Statement No. 115. SFAS No. 159 permits entities to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis. This statement allows entities to measure eligible items at fair value at specified election dates, with resulting changes in fair value reported in earnings. SFAS No. 159 is effective as of the beginning of an entity s first fiscal year that begins after November 15, 2007. We are currently evaluating the provisions of this statement.

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

The following discussion should be read in conjunction with management s discussion and analysis contained in our 2006 Annual Report on Form 10-K, our Form 8-K filed on June 19, 2007 as well as the consolidated financial statements and notes thereto included in this quarterly report on Form 10-Q.

Statements in our discussion may be forward-looking. These forward-looking statements involve risks and uncertainties. For additional risk factors affecting our business, see the information in Item 1A in our 2006 Annual Report on Form 10-K and subsequent filings. Except where noted, discussions in this report relate to our continuing operations.

Critical Accounting Estimates and Policies

The preparation of financial statements in accordance with generally accepted accounting principles requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. Actual results could differ from the estimates and assumptions used. There have been no significant changes to our critical accounting estimates or policies subsequent to December 31, 2006.

Results of Continuing Operations

Volume data

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Production:				
Crude oil (bbls)	839,863	768,832	2,559,992	2,264,827
NGLs (bbls)	284,088	277,161	837,625	831,814
Natural gas (mcf)	23,261,704	18,889,135	64,469,734	51,157,365
Total (mcfe) [(a)]	30,005,410	25,165,093	84,855,436	69,737,211
Average daily production:				
Crude oil (bbls)	9,129	8,357	9,377	8,296
NGLs (bbls)	3,088	3,013	3,068	3,047
Natural gas (mcf)	252,845	205,317	236,153	187,390
Total (mcfe) [(a)]	326,146	273,534	310,826	255,448

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

Overview

Total revenues increased 10% for the third quarter of 2007 over the same period of 2006. This increase is due to higher production and realized prices. These increases were partially offset by a lower gain from derivative fair value income. For the third quarter of 2007, production increased 19% due to the continued success of our drilling program and acquisitions. Realized oil and gas prices were 20% higher in the third quarter of 2007 compared to the same period of 2006. Our hedges increased oil and gas sales by $4.1 million in the third quarter of 2007 compared to a decrease of $23.0 million in the same period of 2006.

Higher production volumes and higher realized oil and gas prices have improved our profit margins. However, Range and the oil and gas industry as a whole continued to experience higher operating costs due to heightened competition for qualified employees, goods and services. On a unit cost basis, our direct operating costs increased $0.04 per mcfe, a 4% increase from the third quarter of 2006 to the third quarter of 2007. It is anticipated that service and personnel costs will remain high as long as oil and gas industry fundamentals remain favorable.

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In the first quarter of 2007, we sold our Gulf of Mexico assets and our Austin Chalk properties that were purchased as part of our Stroud acquisition. These operations are shown in discontinued operations for all periods presented.

Comparison of Quarter Ended September 30, 2007 and 2006

Oil and gas sales and average price calculations for the three months ended September 30, 2007 and 2006 (in thousands) are summarized in the following tables:

	Three Months Ended September 30,			
	2007	2006	Change	%
Oil and Gas Sales:				
Oil wellhead	$ 59,218	$ 49,611	$ 9,607	19%
Oil hedges realized	(5,120)	(13,993)	8,873	63%
Total oil revenue	$ 54,098	$ 35,618	$ 18,480	52%
Gas wellhead	$ 138,832	$ 115,534	$ 23,298	20%
Gas hedges realized	9,235	(9,040)	18,275	202%
Total gas revenue	$ 148,067	$ 106,494	$ 41,573	39%
NGL revenue	$ 12,259	$ 10,942	$ 1,317	12%
Combined wellhead	$ 210,309	$ 176,087	$ 34,222	19%
Combined hedges realized	4,115	(23,033)	27,148	118%
Total oil and gas sales	$ 214,424	$ 153,054	$ 61,370	40%
Components of Derivative Fair Value Income:				
Change in unrealized mark-to-market on oil and gas derivative contracts not designated as hedges[a]	$ 5,618	$ 54,950	$ (49,332)	90%
Cash receipts realized on settlements of non-hedge contracts gas[d]	19,417	10,356	9,061	87%
Cash payments realized on settlements of non-hedge contracts oil[d]	(33)		(33)	
Derivative fair value income	$ 25,002	$ 65,306	$ (40,304)	62%
Average Sales Price Calculation:				
Average sales prices (wellhead):				
Crude oil (per bbl)	$ 70.51	$ 64.53	$ 5.98	9%
NGLs (per bbl)	$ 43.15	$ 39.48	$ 3.67	9%
Natural gas (per mcf)	$ 5.97	$ 6.12	$ (0.15)	2%

Total (per mcfe) [b]	$ 7.01	$ 7.00	$ 0.01	
Average sales prices (including hedges):				
Crude oil (per bbl)	$ 64.41	$ 46.33	$ 18.08	39%
NGLs (per bbl)	$ 43.15	$ 39.48	$ 3.67	9%
Natural gas (per mcf)	$ 6.37	$ 5.64	$ 0.73	13%
Total (per mcfe) [b]	$ 7.15	$ 6.08	$ 1.07	18%
Average sales prices (including all derivative settlements):				
Crude oil (per bbl)	$ 64.37	$ 46.33	$ 18.04	39%
NGLs (per bbl)	$ 43.15	$ 39.48	$ 3.67	9%
Natural gas (per mcf)	$ 7.20	$ 6.19	$ 1.01	17%
Total (per mcfe) [b]	$ 7.79	$ 6.49	$ 1.30	20%
Average NYMEX prices[c]				
Oil (per bbl)	$ 75.38	$ 70.48	$ 4.90	7%
Natural gas (per mcf)	$ 6.13	$ 6.53	$ (0.40)	6%

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

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

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

(d) These amounts represent the realized gains and losses on settled non-hedge derivative, which prior to settlement have been recognized as unrealized mark-to-market gains and losses within derivative fair value income.

The average sales price (including all derivative settlements) received for oil, gas and NGLs during the third quarter of 2007 was $7.79 per mcfe, up 20% or $1.30 per mcfe from the same quarter of the prior year. The average price received in the third quarter for oil increased 39% to $64.37 per barrel and increased 17% to $7.20 per mcf for gas from the same period of 2006. Our derivative program increased realized prices $0.78 per mcfe in the third quarter of 2007 versus a decrease of $0.51 per mcfe in the same period of 2006.

Production volumes increased 19% from the third quarter of 2006 due to continued drilling success and acquisitions partially offset by natural decline. Production for the third quarter was 326.1 Mmcfe per day of which 60% was attributable to the Southwestern division, 38% to the Appalachian division and 2% to the Gulf Coast division.

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Derivative fair value income includes a gain of $25.0 million in 2007 compared to a gain of $65.3 million in the same period of 2006. Beginning in the fourth quarter of 2005, certain of our gas hedges no longer qualified for hedge accounting due to the effect of gas price volatility on the correlation between realized prices and hedge reference prices. Also, as a result of the sale of our Gulf of Mexico assets in the first quarter of 2007, the portion of our derivatives which were designated to our Gulf of Mexico production is now being marked to market. The loss of hedge accounting treatment creates volatility in our revenues as gains and losses from non-hedge derivatives are included in total revenues and are not included in other comprehensive income. As commodity prices increase or decrease, such changes will have an opposite effect on the mark-to-market value of our derivatives. Because gas prices decreased in the third quarter, our derivatives became comparatively more valuable. However, we expect these gains will be offset by lower wellhead revenues in the future. Beginning in the third quarter of 2007, we have also entered into basis swap agreements which do not qualify as hedges for hedge accounting purposes and are also marked to market.

Transportation and gathering revenue of $508,000 decreased $507,000 from 2006. This decrease is primarily due to lower processing margins and lower transmission revenues.

Other revenue increased in 2007 to $2.4 million from $250,000 in 2006. The 2007 period includes $28,000 of ineffective hedging losses, income from equity method investments of $483,000 and $2.2 million of proceeds received from insurance settlements. Other revenue for 2006 includes $184,000 of ineffective hedging gains. The ineffective hedging gains are related to those derivatives that qualified for hedge accounting.

Our unit costs have increased as we continue to grow. We believe some of our expense fluctuations are best analyzed on a unit-of-production, or per mcfe basis. The following presents information about certain of our expenses on an mcfe basis for the three months ended September 30, 2007 and 2006:

Expenses per mcfe	2007	2006	Change	%
Direct operating expense (excluding $0.01 per mcfe stock-based compensation in 2007 and $0.02 per mcfe in 2006)	$0.92	$0.87	$ 0.05	6%
Production and ad valorem tax expense	0.38	0.39	(0.01)	3%
General and administrative expense (excluding stock-based compensation of $0.16 per mcfe in 2007 and $0.16 per mcfe in 2006)	0.44	0.33	0.11	33%
Interest expense	0.66	0.65	0.01	2%
Depletion, depreciation and amortization expense	1.90	1.61	0.29	18%

Direct operating expense (excluding stock-based compensation) increased $5.6 million in the third quarter of 2007 to $27.5 million due to higher oilfield service costs and higher volumes. Our operating expenses are increasing as we add new wells and maintain production from our existing properties. We incurred $1.9 million ($0.06 per mcfe) of workover costs in 2007 versus $712,000 ($0.03 per mcfe) in 2006. On a per mcfe basis, direct operating expenses (excluding stock-based compensation) increased $0.05 from the same period of 2006 with the increase consisting primarily of higher water disposal costs ($0.01 per mcfe) and higher workover costs ($0.03 per mcfe).

Production and ad valorem taxes are paid based on market prices, not hedged prices. These taxes increased $1.4 million or 15% from the same period of the prior year due to higher volumes and higher prices. On a per mcfe basis, production and ad valorem taxes decreased to $0.38 in 2007 from $0.39 in the same period of 2006.

General and administrative expense (excluding stock-based compensation) for the third quarter of 2007 increased $5.1 million to $13.3 million from 2006 primarily due to higher salaries and benefits ($3.1 million), higher office rent and general office expense ($690,000) and higher professional and accounting fees ($554,000). On a per mcfe basis, general and administration expense (excluding stock-based compensation) increased from $0.33 in the third quarter of 2006 to $0.44 in the third quarter of 2007.

Interest expense for the third quarter of 2007 increased $3.5 million to $19.9 million due to higher debt balances and the refinancing of floating bank debt to higher fixed rate debt. In 2006, we issued $250.0 million of 7.5% Notes due 2016 which added $896,000 of interest costs in the third quarter of 2007. In September 2007, we issued

$250.0 million of 7.5% Notes due 2017 which added $156,000 of interest costs in the third quarter of 2007. The proceeds from the issuance of both of the 7.5% subordinated notes were used to retire lower floating rate bank debt and we issued the longer term, fixed rate debt to better match the maturities of our debt with the life of our properties. Average debt outstanding on the bank credit facility for the third quarter of 2007 was $492.6 million compared to $412.9 million for the third quarter of 2006 and the average interest rates were 6.5% in the third quarter of 2007 compared to 6.7% in the same quarter of the prior year.

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Depletion, depreciation and amortization (DD&A) increased $16.4 million or 40% to $57.0 million in the third quarter of 2007 with a 19% increase in production, an 18% increase in depletion rates and a $1.7 million unproved acreage impairment in our Gulf Coast business unit. The increase in DD&A per mcfe is related to our Stroud acquisition, increasing drilling costs, the mix of our production and a $0.06 per mcfe unproved acreage impairment. On a per mcfe basis, DD&A increased from $1.61 in the third quarter of 2006 to $1.90 in the third quarter of 2007.

Costs and expenses also include stock-based compensation, exploration expense and non-cash deferred compensation plan expenses that generally do not trend with production. In 2006 and 2007, stock-based compensation represents the amortization of restricted stock grants and other stock-based compensation under SFAS No. 123(R). In 2007, stock-based compensation is a component of direct operating expense ($485,000), exploration expense ($931,000), general and administrative expense ($4.7 million) and a $103,000 reduction of net gas transportation revenues for a total of $6.2 million. In 2006, stock-based compensation is a component of direct operating expense ($378,000), exploration expense ($757,000), general and administrative expense ($3.9 million) and an $86,000 reduction of net gas transportation revenues for a total of $5.1 million.

Exploration expense for the third quarter of 2007 decreased $10.3 million to $6.2 million due to lower dry hole and seismic costs. The following table details our exploration-related expenses for the three months ended September 30, 2007 and 2006 (in thousands):

Exploration expenses	2007	2006	Change	%
Dry hole expense	$ 173	$ 5,564	$ (5,391)	97%
Seismic	1,924	7,248	(5,324)	73%
Personnel expense	2,216	1,761	455	26%
Stock-based compensation expense	930	757	173	23%
Delay rentals and other	990	1,178	(188)	16%
Total exploration expense	$ 6,233	$ 16,508	$ (10,275)	62%

Deferred compensation plan expense for the third quarter of 2007 increased $10.4 million to $7.8 million from the same period of 2006 due to an increase in our stock price. Our stock price increased from $37.41 at June 30, 2007 to $40.66 at September 30, 2007. This non-cash category reflects increases or decreases in value of our common stock and other investments held in our non-qualified deferred compensation plans.

Income tax expense for 2007 decreased to $34.9 million reflecting an 11% decrease in income from continuing operations before taxes compared to the same period of 2006. The third quarter of 2007 provides for tax expense at an effective rate of approximately 37% compared to 38% in the same period of 2006. Current income tax expense of $133,000 represents state income tax of $283,000 offset by a reduction of federal tax expense of $150,000. See also Note 5 to our consolidated financial statements.

Discontinued operations include the operating results related to our Gulf of Mexico properties and Austin Chalk properties that we sold in the first quarter of 2007. The third quarter of 2007 and 2006 provide for tax expense at an effective rate of approximately 35%. See also Note 4 to our consolidated financial statements.

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Comparison of Nine Months Ended September 30, 2007 and 2006

Oil and gas sales and average price calculations for the nine months ended September 30, 2007 and 2006 (in thousands) are summarized in the following tables:

	Nine Months Ended September 30,			
	2007	2006	Change	%
Oil and Gas Sales:				
Oil wellhead	$ 161,019	$ 143,213	$ 17,806	12%
Oil hedges realized	(7,068)	(37,239)	30,171	81%
Total oil revenue	$ 153,951	$ 105,974	$ 47,977	45%
Gas wellhead	$ 414,758	$ 350,489	$ 64,269	18%
Gas hedges realized	21,136	(42,332)	63,468	150%
Total gas revenue	$ 435,894	$ 308,157	$ 127,737	41%
NGL revenue	$ 31,791	$ 29,012	$ 2,779	10%
Combined wellhead	$ 607,568	$ 522,714	$ 84,854	16%
Combined hedges realized	14,068	(79,571)	93,639	118%
Total oil and gas sales	$ 621,636	$ 443,143	$ 178,493	40%
Components of Derivative Fair Value Income:				
Change in unrealized mark-to-market on oil and gas derivative contracts not designated as hedges[a]	$ (40,171)	$ 83,734	$ (123,905)	148%
Cash receipts realized on settlements of non-hedge contracts gas[d]	50,818	36,180	14,638	40%
Cash payments realized on settlements of non-hedge contracts oil[d]	(29)		(29)	
Derivative fair value income	$ 10,618	$ 119,914	$ (109,296)	91%
Average Sales Price Calculation:				
Average sales prices (wellhead):				
Crude oil (per bbl)	$ 62.90	$ 63.23	$ (0.33)	1%
NGLs (per bbl)	$ 37.95	$ 34.88	$ 3.07	9%
Natural gas (per mcf)	$ 6.43	$ 6.95	$ (0.52)	7%
Total (per mcfe) [b]	$ 7.16	$ 7.50	$ (0.34)	5%

Average sales prices (including hedges)				
Crude oil (per bbl)	$ 60.14	$ 46.79	$ 13.35	29%
NGLs (per bbl)	$ 37.95	$ 34.88	$ 3.07	9%
Natural gas (per mcf)	$ 6.76	$ 6.02	$ 0.74	12%
Total (per mcfe) (b)	$ 7.33	$ 6.35	$ 0.98	15%
Average sales prices (including all derivative settlements):				
Crude oil (per bbl)	$ 60.13	$ 46.79	$ 13.34	29%
NGLs (per bbl)	$ 37.95	$ 34.88	$ 3.07	9%
Natural gas (per mcf)	$ 7.55	$ 6.73	$ 0.82	12%
Total (per mcfe) (b)	$ 7.92	$ 6.87	$ 1.05	15%
Average NYMEX prices(c)				
Oil (per bbl)	$ 66.23	$ 68.22	$ (1.99)	3%
Natural gas (per mcf)	$ 6.88	$ 7.47	$ (0.59)	8%

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

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

(c) Based on average bid week prompt month prices.

(d) These amounts represent the realized gains and losses on settled non-hedge derivative, which prior to settlement have been recognized as unrealized mark-to-market gains and losses within derivative fair value income.

The average sales price (including all derivative settlements) received for oil, gas and NGLs during the first nine months of 2007 was $7.92 per mcfe, up 15% or $1.05 per mcfe from the same period of the prior year. The average price received in the first nine months for oil increased 29% to $60.13 per barrel and increased 12% to $7.55 per mcf for gas from the same period of 2006. Our derivative program increased realized prices $0.76 per mcfe in the first nine months of 2007 versus a decrease of $0.63 per mcfe in the same period of 2006.

Production volumes increased 22% from the first nine months of 2006 primarily due to continued drilling success and acquisitions partially offset by natural decline. Production for the first nine months was 310.8 Mmcfe per day of which 61% was attributable to the Southwestern division, 37% to the Appalachian division and 2% to the Gulf Coast division.

Derivative fair value income includes a gain of $10.6 million in 2007 compared to a gain of $119.9 million in the same period of 2006. In the fourth quarter of 2005, certain of our gas hedges no longer qualified for hedge accounting due to the effect of gas price volatility on the correlation between realized prices and hedge reference prices. Also, as a result of the

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sale of our Gulf of Mexico assets in the first quarter of 2007, a portion of the derivatives which were designated to our Gulf of Mexico production is now being marked to market. The loss of hedge accounting treatment creates volatility in our revenues as gains and losses from non-hedge derivatives are not included in other comprehensive income. Because gas prices decreased in the first nine months, our derivatives became comparatively more valuable. However, we expect these gains will be offset by lower wellhead revenues in the future. Beginning in the third quarter of 2007, we also have entered into basis swap agreements which do not qualify as hedges for hedge accounting purposes and are marked to market.

Other revenue increased in 2007 to $5.3 million from $3.3 million in 2006. The 2007 period includes insurance proceeds of $2.8 million, income from equity method investments of $1.3 million and $502,000 of ineffective hedging gains. Other revenue for 2006 includes $3.5 million of ineffective hedging gains. The ineffective hedging gains are related to those derivatives that qualified for hedge accounting.

Our unit costs have increased as we continue to grow. We believe some of our expense fluctuations are best analyzed on a unit-of-production, or per mcfe basis. The following presents information about certain of our expenses on an mcfe basis for the nine months ended September 30, 2007 and 2006:

Expenses per mcfe	2007	2006	Change	%
Direct operating expense (excluding $0.02 per mcfe stock-based compensation in 2007 and $0.01 per mcfe in 2006)	$0.91	$0.81	$ 0.10	12%
Production and ad valorem tax expense	0.39	0.40	(0.01)	3%
General and administrative expense (excluding stock-based compensation of $0.16 per mcfe in 2007 and $0.14 per mcfe in 2006)	0.43	0.37	0.06	16%
Interest expense	0.66	0.54	0.12	22%
Depletion, depreciation and amortization expense	1.84	1.53	0.31	20%

Direct operating expense (excluding stock-based compensation) increased $20.5 million in the first nine months of 2007 to $76.9 million due to higher oilfield service costs, higher volumes and our acquisitions. Our operating expenses are increasing as we add new wells and maintain production from our existing properties. We incurred $5.2 million ($0.06 per mcfe) of workover costs in 2007 versus $2.1 million ($0.03 per mcfe) in 2006. On a per mcfe basis, direct operating expenses (excluding stock-based compensation) increased $0.10 from the same period of 2006 with the increase consisting primarily of higher water disposal costs ($0.03 per mcfe), higher well service costs ($0.04 per mcfe) and higher workover costs ($0.03 per mcfe).

Production and ad valorem taxes are paid based on market prices, not hedged prices. These taxes increased $5.0 million or 18% from the same period of the prior year due to higher volumes offset by lower prices and assessed values. On a per mcfe basis, production and ad valorem taxes decreased to $0.39 in 2007 from $0.40 in the same period of 2006.

General and administrative expense (excluding stock-based compensation) for the first nine months of 2007 increased $11.2 million to $36.9 million primarily due to higher salaries and benefits ($7.7 million), higher office rent and general office expense ($1.5 million) and higher professional and accounting fees ($1.2 million). On a per mcfe basis, general and administration expense (excluding stock-based compensation) increased from $0.37 in the first nine months of 2006 to $0.43 in the first nine months of 2007.

Interest expense for the first nine months of 2007 increased $18.1 million to $56.4 million due to rising interest rates, higher average debt balances and the refinancing of floating bank debt to higher fixed rate debt. In 2006, we issued $250.0 million of 7.5% Notes due 2016 which added $9.1 million of interest costs in the first nine months of 2007. In September 2007, we issued $250.0 million of 7.5% Notes due 2017 which added $156,000 of interest costs in the first nine months of 2007. The proceeds from the issuance of both the 7.5% senior subordinated notes were used to retire lower floating rate bank debt and we issued the longer term, fixed rate debt to better match the maturities of our debt with the life of our properties. Average debt outstanding on the bank credit facility for the first nine months of 2007 was $452.5 million compared to $318.7 million for the first nine months of 2006 and the average interest rates were 6.5% in the first nine months of 2007 compared to 6.3% in the same period of the prior year.

Depletion, depreciation and amortization (DD&A) increased $49.5 million or 47% to $155.8 million in the first nine months of 2007 with a 22% increase in production, a 20% increase in depletion rates and a $1.7 million acreage impairment. The increase in DD&A per mcfe is related to our Stroud acquisition, increasing drilling costs, the mix of our production and a $0.02 per mcfe unproved acreage impairment. On a per mcfe basis, DD&A increased from $1.53 in the first nine months of 2006 to $1.84 in the first nine months of 2007.

Costs and expenses also include stock-based compensation, exploration expense and non-cash deferred compensation plan expenses that generally do not trend with production. In 2006 and 2007, stock-based compensation represents the amortization of restricted stock grants and other stock-based compensation under SFAS No. 123(R). In 2007, stock-based compensation is a component of direct operating expense ($1.4 million), exploration expense ($2.6 million), general and administrative expense ($13.7 million) and a $297,000 reduction of net gas transportation revenues for a total of $18.0 million. In 2006, stock-based compensation is a component of direct operating expense ($1.0 million), exploration expense ($2.2 million), general and administrative expense ($10.3 million) and a $237,000 reduction of net gas transportation revenues for a total of $13.8 million.

Exploration expense for the first nine months of 2007 decreased $3.5 million to $29.7 million due to lower seismic costs partially offset by higher personnel costs. The following table details our exploration-related expenses for the first nine months ended September 30, 2007 and 2006 (in thousands):

Exploration expenses	2007	2006	Change	%
Dry hole expense	$ 9,071	$ 9,293	$ (222)	2%
Seismic	8,260	14,191	(5,931)	42%
Personnel expense	6,543	4,925	1,618	33%
Stock-based compensation expense	2,589	2,196	393	18%
Delay rentals and other	3,205	2,588	617	24%
Total exploration expense	$ 29,668	$ 33,193	$ (3,525)	11%

Deferred compensation plan expense for the first nine months of 2007 increased $28.7 million from the same period of 2006 due to an increase in our stock price. Our stock price increased from $27.46 at December 31, 2006 to $40.66 at September 30, 2007. This non-cash category reflects increases or decreases in value of our common stock and other investments held in our non-qualified deferred compensation plans.

Income t**ax expense** for 2007 decreased to $74.1 million reflecting the 23% decrease in income from continuing operations before taxes compared to the same period of 2006. The first nine months of 2007 provides for tax expense at an effective rate of approximately 36% compared to 38% in the same period of 2006. The nine months ended September 30, 2007 includes a non-recurring $3.0 million tax benefit related to an increase in the Texas margin tax credit carryover. Current income tax of $416,000 represents state income tax of $545,000 offset by a reduction of federal tax expense of $129,000. See also Note 5 to our consolidated financial statements.

Discontinued operations include the operating results related to our Gulf of Mexico properties and Austin Chalk properties that we sold in the first quarter of 2007. The first nine months of 2007 and 2006 provide for tax expense at an effective rate of approximately 35%. See also Note 4 to our consolidated financial statements.

Liquidity and Capital Resources

Our main sources of liquidity and capital resources are internally generated cash flow from operations, a committed bank credit facility and access to both the debt and equity capital markets. During the nine months ended September 30, 2007, net cash provided from continuing operations of $445.5 million, proceeds from our April 2007 common stock offering of $280.4 million and proceeds from the sale of assets of $234.3 million were used to fund $1.0 billion of capital expenditures (including acquisitions and equity investments). At September 30, 2007, we had $187,000 in cash and total assets of $3.8 billion. Our debt to capitalization ratio was 39.4% at September 30, 2007 compared to 45.5% at December 31, 2006. As of September 30, 2007 and December 31, 2006, our total capitalization was as follows (in thousands):

	September 30, 2007	December 31, 2006
Bank debt	$ 266,000	$ 452,000
Senior subordinated notes	847,062	596,782

Total debt	1,113,062	1,048,782
Stockholders equity	1,708,812	1,256,161
Total capitalization	$ 2,821,874	$ 2,304,943

Long-term debt at September 30, 2007 totaled $1.1 billion, including $266.0 million of bank credit facility debt and $847.1 million of senior subordinated notes. Available borrowing capacity under the bank credit facility at September 30, 2007 was $634.0 million. Cash is required to fund capital expenditures necessary to offset inherent declines in production and proven reserves which is typical in the capital-intensive oil and gas industry. Future success in growing reserves and production will be highly dependent on capital resources available and the success of finding or acquiring additional reserves. We believe that net cash generated from operating activities and unused committed borrowing capacity under the bank credit facility combined with our oil and gas price hedges currently in place will be adequate to satisfy near-term financial obligations and liquidity needs. However, long-term cash flows are subject to a number of variables including the level of production and prices as well as various economic conditions that have historically affected the oil and gas business. A material drop in oil and gas prices or a reduction in production and reserves would reduce our ability to fund capital expenditures, reduce debt, meet financial obligations and remain profitable. We operate in an environment with numerous financial and operating risks, including, but not limited to, the inherent risks of the search for, development and production of oil and gas, the ability to buy properties and sell production at prices which provide an attractive return and the highly competitive nature of the industry. Our ability to expand our reserve base is, in part, dependent on obtaining sufficient capital through internal cash flow, bank borrowings, asset sales or the issuance of debt or equity securities. There can be no assurance that internal cash flow and other capital sources will provide sufficient funds to maintain capital expenditures on prospective projects that we believe are necessary to offset inherent declines in production and proven reserves.

Bank Debt and Senior Subordinated Notes

The debt agreements contain covenants relating to working capital, dividends and financial ratios. We were in compliance with all covenants at September 30, 2007. Under the bank credit facility, common and preferred dividends are permitted, subject to the terms of the restricted payment basket. The bank credit facility provides for a restricted payment basket of $20.0 million plus 50% of net income plus 66-2/3% of net cash proceeds from common stock issuances occurring since December 31, 2001. Approximately $726.4 million was available under the bank credit facility s restricted payment basket on September 30, 2007. The terms of our senior subordinated notes limit restricted payments (including dividends) to the greater of $20.0 million or a formula based on earnings since the issuance of the notes and 100% of net cash proceeds from common stock issuances. The 7.5% Notes due 2016 also allow for any cash proceeds received from the sale of oil and gas properties purchased in the Stroud acquisition to be added to the restricted payment basket. Approximately $900.8 million was available under the restricted payment basket for each of the 7.375% Notes, 6.375% Notes and the 7.5% Notes due 2017 on September 30, 2007. There was $981.8 million available under the restricted payment basket for 7.5% Notes due 2016 at September 30, 2007.

On September 28, 2007, we issued $250.0 million principal amount of 7.5% senior subordinated notes due 2017. The proceeds from the issuance of these notes were used to pay down our bank credit facility. We maintain a $900.0 million revolving bank credit facility commitment. The facility is secured by substantially all our assets. Availability under the facility is subject to a borrowing base set by the banks semi-annually and in certain other circumstances more frequently. The borrowing base is dependent on a number of factors, primarily the lenders assessment of future cash flows. Redeterminations other than increases require the approval of 75% of the lenders, while increases require unanimous approval. On October 22, 2007, the borrowing base was redetermined to be $1.5 billion and the maturity date was extended to October 25, 2012. Credit availability is equal to the lesser of the facility amount or the borrowing base, resulting in credit availability of $589.0 million on October 22, 2007.

Cash Flow

Our principal sources of cash are operating cash flow and bank borrowings and at times, the sale of assets and the issuance of debt and equity securities. Our operating cash flow is highly dependent on oil and gas prices. As of September 30, 2007, we have entered into derivative agreements covering 23.5 Bcfe, 89.3 Bcfe and 32.1 Bcfe for 2007, 2008 and 2009, which represents 80%, 72% and 24% of our forecasted production, respectively. Net cash provided from continuing operations for the nine months ended September 30, 2007 was $445.5 million compared to $319.7 million in the nine months ended September 30, 2006. Cash flow from operations was higher than the prior year due to higher volumes and realized prices partially offset by higher operating costs. Net cash used in investing for the nine months ended September 30, 2007 was $798.3 million compared to $714.6 million in the same period of

2006. The 2007 period includes $601.0 million of additions to oil and gas properties and $309.7 million of acquisitions, partially offset by proceeds of $234.3 million from asset sales. The 2006 period included $328.4 million of additions to oil and gas properties and $336.7 million of acquisitions. Net cash provided from financing for the nine months ended September 30, 2007 was $340.4 million compared to $364.0 million in the first nine months of 2006. During the first nine months of 2007 total debt increased $64.3 million.

Dividends

On September 1, 2007, the Board of Directors declared a dividend of three cents per share ($4.5 million) on our common stock, payable on September 28, 2007 to stockholders of record at the close of business on September 17, 2007.

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Capital Requirements and Contractual Cash Obligations

The 2007 capital budget is currently set at $890.0 million (excluding acquisitions) and based on current projections, is expected to be funded with internal cash flow and asset sales. For the nine months ended September 30, 2007, $616.2 million of development and exploration spending was funded with internal cash flow and proceeds from the sale of assets.

There have been no significant changes to our contractual obligations subsequent to December 31, 2006. There have been no significant changes to our off-balance sheet arrangements subsequent to December 31, 2006.

Other Contingencies

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

Hedging Oil and Gas Prices

We enter into derivative agreements to reduce the impact of oil and gas price volatility on our operations. At September 30, 2007, swaps were in place covering 73.9 Bcf of gas at prices averaging $8.99 per mcf. We also had collars covering 29.2 Bcf of gas at weighted average floor and cap prices which range from $7.68 to $10.94 per mcf, and 7.0 million barrels of oil at weighted average floor and cap prices that range from $61.11 to $74.99 per barrel. The derivative fair value, represented by the estimated amount that would be realized or payable on termination, based on a comparison of the contract price and a reference price, generally NYMEX, was a net unrealized pre-tax gain of $68.9 million at September 30, 2007. Settled transaction gains and losses for derivatives that qualify for hedge accounting are determined monthly and are included as increases or decreases in oil and gas revenues in the period the hedged production is sold. An ineffective portion (changes in contract prices that do not match changes in the hedge price) of open hedge contracts that qualify for hedge accounting is recognized in earnings quarterly in other revenue.

At September 30, 2007, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Average Hedge Price
Natural Gas			
2007 4th quarter	Swaps	107,500 Mmbtu/day	$9.49
2007 4th quarter	Collars	98,500 Mmbtu/day	$7.12 - $9.93
2008	Swaps	135,000 Mmbtu/day	$9.11
2008	Collars	55,000 Mmbtu/day	$7.93 - $11.40
2009	Swaps	40,000 Mmbtu/day	$8.24
Crude Oil			
2007 4th quarter	Collars	8,300 bbl/day	$57.69 - $68.98
2008	Collars	9,000 bbl/day	$59.34 - $75.48
2009	Collars	8,000 bbl/day	$64.01 - $76.00

As of the fourth quarter of 2005, certain of our gas hedges no longer qualify for hedge accounting and are marked to market. Also, as a result of the sale of our Gulf of Mexico assets in the first quarter of 2007, a portion of derivatives which were designated to our Gulf Coast production is now being marked to market. As of September 30, 2007 hedges on 63.1 Bcfe no longer qualify or are not designated for hedge accounting.

During the third quarter of 2007, in addition to the swaps and collars above, we entered into basis swap agreements which do not qualify as hedges for hedge accounting purposes and are marked to market. The price we receive for our production can be less than NYMEX price because of adjustments for delivery location (basis), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively fix the basis adjustments. The fair value of the basis swaps was a net unrealized pre tax gain of $1.3 million at September 30, 2007. All of these situations where we are marking derivatives to market resulted in a gain of $10.6 million in the first nine months of 2007 compared to a gain of $119.9 million in the first nine months of 2006.

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Interest Rates

At September 30, 2007, we had $1.1 billion of debt outstanding. Of this amount, $850.0 million bore interest at fixed rates averaging 7.3%. Bank debt totaling $266.0 million bears interest at floating rates, which average 6.3% at September 30, 2007. The 30 day LIBOR rate on September 30, 2007 was 5.1%.

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 oil and gas prices, the costs to produce our reserves and capital market availability. Oil and gas prices are subject to significant fluctuations that are beyond our ability to control or predict. During the third quarter of 2007, we received an average of $70.51 per barrel of oil and $5.97 per mcf of gas before derivative contracts compared to $64.53 per barrel of oil and $6.12 per mcf of gas in the same period of the prior year. Although certain of our costs are affected by general inflation, inflation does not normally have a significant effect on our business. Commodity prices for oil and gas increased significantly in 2004, 2005 and 2006 and commodity prices for oil continued to increase in 2007. The higher prices have led to increased activity in the industry and, consequently, rising costs. These cost trends have put pressure not only on our operating costs but also on capital costs. We expect these costs to remain high for the remainder of 2007 even in the face of moderating or declining near-term gas prices.

New Accounting Standards

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. SFAS No. 157 standardizes the definition of fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures related to the use of fair value measures in financial statements. SFAS No. 157 applies whenever other standards require (or permit) assets or liabilities to be measured at fair value but does not expand the use of fair value measurements. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. We do not expect the implementation of SFAS 157 to have a material impact on our results of operations or financial condition.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities including an amendment of FASB Statement No. 115. SFAS No. 159 permits entities to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis. This statement allows entities to measure eligible items at fair value at specified election dates, with resulting changes in fair value reported in earnings. SFAS No. 159 is effective as of the beginning of an entity s first fiscal year that begins after November 15, 2007. We are currently evaluating the provisions of this statement.

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Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

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

Commodity Price Risk. We periodically enter into hedging arrangements with respect to our oil and gas production. These arrangements are intended to reduce the impact of oil and gas price fluctuations. Certain of our derivatives are swaps where we receive a fixed price for our production and pay market prices to the counterparty. Our derivatives program also includes collars which establish a minimum floor price and a predetermined ceiling price. Realized gains or losses on derivatives that qualify for hedge accounting are recognized in oil and gas revenue when the associated production occurs. Gains or losses on open contracts are recorded either in current period income or other comprehensive income. Generally, derivative losses occur when market prices increase, which are offset by gains on the underlying commodity transaction. Conversely, derivative gains occur when market prices decrease, which are offset by losses on the underlying commodity transaction. Ineffective gains and losses on those derivatives that qualify for hedge accounting are recognized in earnings in other revenues. We do not enter into derivative instruments for trading purposes. Though not all of our derivatives qualify or are designated as accounting hedges, the purpose of entering into the contracts is to economically hedge oil and gas prices. Those that do not qualify as accounting hedges are marked to market through earnings in the line derivative fair value income.

As of September 30, 2007, we had gas swaps in place covering 73.9 Bcf of gas. We also had collars covering 29.2 Bcf of gas and 7.0 million barrels of oil. Their fair value, represented by the estimated amount that would be realized upon immediate liquidation, based on contract versus NYMEX prices, approximated a net unrealized pre-tax gain of $68.9 million at that date. These contracts expire monthly through December 2009. Gains or losses on open and closed hedging transactions are determined as the difference between the contract price received by us for the sale of our hedged production and the hedge price, generally closing prices on the NYMEX. Losses or gains due to commodity hedge ineffectiveness on derivatives that qualify for hedge accounting are recognized in earnings in other revenues in our consolidated statement of operations.

At September 30, 2007, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Average Hedge Price	Fair Market Value (In thousands)
Natural Gas				
2007 4th quarter	Swaps	107,500 Mmbtu/day	$9.49	$ 24,435
2007 4th quarter	Collars	98,500 Mmbtu/day	$7.12 - $9.93	$ 5,284
2008	Swaps	135,000 Mmbtu/day	$9.11	$ 55,330
2008	Collars	55,000 Mmbtu/day	$7.93 - $11.40	$ 14,123
2009	Swaps	40,000 Mmbtu/day	$8.24	$ (397)
Crude Oil				
2007 4th quarter	Collars	8,300 bbl/day	$57.69 - $68.98	$ (9,073)
2008	Collars	9,000 bbl/day	$59.34 - $75.48	$ (15,192)
2009	Collars	8,000 bbl/day	$64.01 - $76.00	$ (5,644)

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. As of the fourth quarter of 2005, certain of our gas hedges no longer qualify for hedge accounting due to the volatility in gas prices and its effect on our basis differentials and are marked to market. Also, as a result of the sale of our Gulf of Mexico assets in the first quarter of 2007 a portion of the derivatives designated against our Gulf of Mexico production is now being marked to market. In addition, during the third quarter of 2007, we entered into basis swap agreements which do not qualify as hedges for hedge accounting purposes and are marked to market. The price we receive for our gas production can be less than NYMEX price because of adjustments for delivery location (basis), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively fix the basis adjustments. The fair value of the basis swaps was a net unrealized pre tax gain of $1.3 million at September 30, 2007. In all of these situations where we are marking derivative instruments to market resulted in a gain of $10.6 million in the first nine months of 2007 compared to a gain of $119.9 million in the same period of 2006.

In the first nine months of 2007, a 10% reduction in oil and gas prices, excluding amounts fixed through hedging transactions, would have reduced revenue by $60.5 million. If oil and gas future prices at September 30, 2007 declined 10%, the unrealized hedging gain at that date would have increased by $87.5 million.

Interest rate risk. At September 30, 2007, we had $1.1 billion of debt outstanding. Of this amount, $850.0 million bore interest at fixed rates averaging 7.3%. Senior debt totaling $266.0 million bore interest at floating rates averaging 6.3%. A 1% increase or decrease in short-term interest rates would affect interest expense by approximately $2.7 million.

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Item 4. CONTROLS AND PROCEDURES

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

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PART II. OTHER INFORMATION

Item IA. Risk Factors

The information presented below updates, and should be read in conjunction with, the risk factors and information disclosed in the Risk Factors section of our 2006 Annual Report on Form 10-K. There have been no material changes from the risk factors and information disclosed in the Risk Factors section of our 2006 Annual Report on Form 10-K except that:

- In light of the sale of our Gulf of Mexico properties in March 2007, we deleted the risk factor entitled A portion of our business is subject to special risks generally related to offshore operations and specifically in the Gulf of Mexico ;

- We revised the risk factor set forth below entitled Hedging transactions may limit our potential gains and involve other risks by adding a new sentence to the risk factor as follows: As a result of the sale of our Gulf of Mexico assets in the first quarter of 2007, a portion of the derivatives which were designated to our Gulf Coast production is now being marked to market ; and

Hedging transactions may limit our potential gains and involve other risks

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

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

- our production is less than expected;

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

- a sudden, unexpected event materially impacts oil or natural gas prices or the relationship between the hedged price index and the oil and gas sales price.

In the fourth quarter of 2005, due to the trading volatility of NYMEX gas contracts, we experienced larger than usual differentials between actual prices paid at delivery points and NYMEX based gas hedges. Due to this event, certain of our gas hedges no longer qualify for hedge accounting and are marked to market. As a result of the sale of our Gulf of Mexico assets in the first quarter of 2007, a portion of the derivatives which were designated to our Gulf Coast production is now being marked to market. This may result in more volatility in our income in future periods.

- We revised the risk factor set forth below entitled Our indebtedness could limit our ability to successfully operate our business to revise the title of the risk factor and to update the capital resource estimates set forth in the risk factor.

Our significant indebtedness could limit our ability to successfully operate our business

We are leveraged and our exploration and development program will require substantial capital resources estimated to range from $800.0 million to $1.1 billion per year over the next three years, depending on the level of drilling and the expected cost of services. Our existing operations will also require ongoing capital expenditures. In addition, if we decide to pursue additional acquisitions, our capital expenditures will increase both to complete such acquisitions and to explore and develop any newly acquired properties.

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

- we may be required to dedicate a substantial portion of our cash flows from operations to the payment of our indebtedness, reducing the funds available for our operations;

- a portion of our borrowings are at variable rates of interest, making us vulnerable to increases in interest rates;

we may be more highly leveraged than some of our competitors, which could place us at a competitive disadvantage;

our degree of leverage may make us more vulnerable to a downturn in our business or the general economy;

the terms of our existing credit arrangements contain numerous financial and other restrictive covenants;

our debt level could limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and

we may have difficulties borrowing money in the future.

Despite our current levels of indebtedness we still may be able to incur substantially more debt. This could further increase the risks described above.

Item 6. Exhibits

(a) EXHIBITS

Exhibit Number	Description
3.1	Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on May 5, 2004 as amended by the Certificate of First Amendment to Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to exhibit 3.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on July 28, 2005)
3.2	Amended and Restated By-laws of Range (incorporated by reference to Exhibit 3.2 to our Form 10-K (File No. 001-12209) as filed with the SEC on March 3, 2004)
10.3	Purchase and Sale Agreement, dated April 13, 2007, by and between Pine Mountain Oil and Gas, Inc. and Equitable Production Company (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on April 16, 2007)
10.4	Contribution Agreement, dated April 13, 2007, by and between Pine Mountain Oil and Gas, Inc., Equitable Production Company, Equitable Gathering Equity, LLC and Nora Gathering LLC (incorporated by reference to Exhibit 10.2 to our Form 8-K (File No. 001-12209) as filed with the SEC on April 16, 2007)
31.1*	Certification by the President 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 President 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

* filed 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.

RANGE RESOURCES CORPORATION

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

October 24, 2007

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