RANGE RESOURCES CORP
Form 10-Q
October 25, 2012


# 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, 2012**

**OR**

¨ **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 ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for shorter period that the registrant was required to submit and post such files). Yes þ No ¨

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

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

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

162,629,126 Common Shares were outstanding on October 22, 2012.

**Table of Contents**

**RANGE RESOURCES CORPORATION**

**FORM 10-Q**

**Quarter Ended September 30, 2012**

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

**TABLE OF CONTENTS**

Table of Contents

**PART I FINANCIAL INFORMATION**

**ITEM 1. Financial Statements**

**RANGE RESOURCES CORPORATION**

**CONSOLIDATED BALANCE SHEETS**

**(In thousands, except per share data)**

| | September 30, 2012 (Unaudited) | December 31, 2011 |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 151 | $ 92 |
| Accounts receivable, less allowance for doubtful accounts of $1,635 and $4,015 | 120,120 | 127,180 |
| Unrealized derivative gain | 131,841 | 173,921 |
| Inventory and other | 18,423 | 14,070 |
| Total current assets | 270,535 | 315,263 |
| Unrealized derivative gain | 20,648 | 77,579 |
| Equity method investments | 135,867 | 138,130 |
| Natural gas and oil properties, successful efforts method | 8,000,845 | 6,784,027 |
| Accumulated depletion and depreciation | (1,942,698) | (1,626,461) |
| | 6,058,147 | 5,157,566 |
| Transportation and field assets | 117,364 | 123,349 |
| Accumulated depreciation and amortization | (73,142) | (70,671) |
| | 44,222 | 52,678 |
| Other assets | 128,301 | 104,254 |
| **Total assets** | $ 6,657,720 | $ 5,845,470 |
| **Liabilities** | | |
| Current liabilities: | | |
| Accounts payable | $ 318,492 | $ 311,369 |
| Asset retirement obligations | 5,005 | 5,005 |
| Accrued liabilities | 133,369 | 109,109 |
| Liabilities of discontinued operations | | 653 |
| Deferred tax liability | 37,300 | 56,595 |
| Accrued interest | 47,284 | 29,201 |
| Unrealized derivative loss | 4,294 | |
| Total current liabilities | 545,744 | 511,932 |
| Bank debt | 461,000 | 187,000 |
| Subordinated notes | 2,388,869 | 1,787,967 |

| | | |
|---|---|---|
| Deferred tax liability | 656,849 | 710,490 |
| Unrealized derivative loss | 8,939 | 173 |
| Deferred compensation liability | 198,082 | 169,188 |
| Asset retirement obligations and other liabilities | 116,410 | 86,300 |
| Total liabilities | 4,375,893 | 3,453,050 |
| Commitments and contingencies | | |
| **Stockholders Equity** | | |
| Preferred stock, $1 par, 10,000,000 shares authorized, none issued and outstanding | | |
| Common stock, $0.01 par, 475,000,000 shares authorized, 162,592,198 issued at September 30, 2012 and 161,302,973 issued at December 31, 2011 | 1,626 | 1,613 |
| Common stock held in treasury, 131,158 shares at September 30, 2012 and 171,426 shares at December 31, 2011 | (4,879) | (6,343) |
| Additional paid-in capital | 1,903,249 | 1,866,554 |
| Retained earnings | 314,534 | 373,969 |
| Accumulated other comprehensive income | 67,297 | 156,627 |
| Total stockholders equity | 2,281,827 | 2,392,420 |
| **Total liabilities and stockholders equity** | $ 6,657,720 | $ 5,845,470 |

**See the accompanying notes.**

Table of Contents

**RANGE RESOURCES CORPORATION**

**CONSOLIDATED STATEMENTS OF OPERATIONS**

**(Unaudited, in thousands, except per share data)**

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2012** | **2011** | **2012** | **2011** |
| **Revenues and other income:** | | | | |
| Natural gas, NGLs and oil sales | $ 337,040 | $ 304,230 | $ 953,006 | $ 841,546 |
| Derivative fair value (loss) income | (40,728) | 65,761 | 47,008 | 77,966 |
| Gain (loss) on the sale of assets | 949 | 203 | (12,704) | (1,280) |
| Other | (2,368) | 442 | (3,084) | 357 |
| Total revenues and other income | 294,893 | 370,636 | 984,226 | 918,589 |
| **Costs and expenses:** | | | | |
| Direct operating | 29,628 | 29,828 | 85,691 | 87,054 |
| Transportation, gathering and compression | 51,600 | 32,431 | 137,164 | 86,179 |
| Production and ad valorem taxes | 8,819 | 7,317 | 57,239 | 21,746 |
| Exploration | 14,752 | 17,606 | 51,785 | 56,385 |
| Abandonment and impairment of unproved properties | 40,118 | 16,627 | 104,048 | 52,064 |
| General and administrative | 44,497 | 35,907 | 127,231 | 108,986 |
| Deferred compensation plan | 20,052 | 8,717 | 21,555 | 33,569 |
| Interest expense | 43,997 | 34,181 | 124,090 | 90,343 |
| Loss on early extinguishment of debt | | (4) | | 18,576 |
| Depletion, depreciation and amortization | 123,059 | 93,619 | 332,012 | 244,129 |
| Impairment of proved properties and other assets | 1,281 | 38,681 | 1,281 | 38,681 |
| Total costs and expenses | 377,803 | 314,910 | 1,042,096 | 837,712 |
| **(Loss) income from continuing operations before income taxes** | (82,910) | 55,726 | (57,870) | 80,877 |
| Income tax (benefit) expense | | | | |
| Current | | (7) | | 1 |
| Deferred | (29,074) | 22,547 | (17,910) | 35,345 |
| | (29,074) | 22,540 | (17,910) | 35,346 |
| **(Loss) income from continuing operations** | (53,836) | 33,186 | (39,960) | 45,531 |
| **Discontinued operations, net of taxes** | | 1,569 | | 15,484 |
| **Net (loss) income** | $ (53,836) | $ 34,755 | $ (39,960) | $ 61,015 |
| **(Loss) income per common share:** | | | | |
| Basic-(loss) income from continuing operations | $ (0.34) | $ 0.21 | $ (0.25) | $ 0.28 |
| -discontinued operations | | 0.01 | | 0.10 |
| -net (loss) income | $ (0.34) | $ 0.22 | $ (0.25) | $ 0.38 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Diluted-(loss) income from continuing operations | $ | (0.34) | $ | 0.20 | $ | (0.25) | $ | 0.28 |
| -discontinued operations | | | | 0.01 | | | | 0.10 |
| -net (loss) income | $ | (0.34) | $ | 0.21 | $ | (0.25) | $ | 0.38 |
| Dividends per common share | $ | 0.04 | $ | 0.04 | $ | 0.12 | $ | 0.12 |
| **Weighted average common shares outstanding:** | | | | | | | | |
| Basic | | 159,563 | | 158,154 | | 159,297 | | 157,901 |
| Diluted | | 159,563 | | 159,322 | | 159,297 | | 158,939 |

**See the accompanying notes.**

2

Table of Contents

**RANGE RESOURCES CORPORATION**

**CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME**

**(Unaudited, in thousands)**

| | Three Months Ended September 30, 2012 | 2011 | Nine Months Ended September 30, 2012 | 2011 |
|---|---|---|---|---|
| **Net (loss) income** | $ (53,836) | $ 34,755 | $ (39,960) | $ 61,015 |
| Other comprehensive income: | | | | |
| Realized loss (gain) on hedge derivative contract settlements reclassified into earnings from other comprehensive income, net of taxes | (37,495) | (16,724) | (120,871) | (55,791) |
| Change in unrealized deferred hedging (losses) gains, net of taxes | (52,246) | 56,993 | 31,541 | 74,530 |
| **Total comprehensive (loss) income** | $ (143,577) | $ 75,024 | $ (129,290) | $ 79,754 |

**See the accompanying notes.**

Table of Contents

**RANGE RESOURCES CORPORATION**

**CONSOLIDATED STATEMENTS OF CASH FLOWS**

**(Unaudited, in thousands)**

| | Nine Months Ended September 30, 2012 | 2011 |
|---|---|---|
| **Operating activities:** | | |
| Net (loss) income | $ (39,960) | $ 61,015 |
| Adjustments to reconcile net (loss) income to net cash provided from operating activities: | | |
| Income from discontinued operations | | (15,484) |
| Loss from equity method investments, net of distributions | 2,252 | 18,777 |
| Deferred income tax (benefit) expense | (17,910) | 35,345 |
| Depletion, depreciation and amortization and impairment | 333,293 | 282,810 |
| Exploration dry hole costs | 832 | 2,516 |
| Mark-to-market on natural gas, NGLs and oil derivatives not designated as hedges | (30,076) | (67,093) |
| Abandonment and impairment of unproved properties | 104,048 | 52,064 |
| Unrealized derivative loss (gain) | 5,061 | (2,531) |
| Allowance for bad debts | | 446 |
| Amortization of deferred financing costs, loss on extinguishment of debt and other | 5,970 | 23,753 |
| Deferred and stock-based compensation | 58,573 | 66,759 |
| Loss on the sale of assets | 12,704 | 1,280 |
| Changes in working capital: | | |
| Accounts receivable | (9,479) | (34,356) |
| Inventory and other | (5,394) | 875 |
| Accounts payable | 11,074 | (7,262) |
| Accrued liabilities and other | 30,135 | 9,953 |
| Net cash provided from continuing operations | 461,123 | 428,867 |
| Net cash provided from discontinued operations | | 19,478 |
| Net cash provided from operating activities | 461,123 | 448,345 |
| **Investing activities:** | | |
| Additions to natural gas and oil properties | (1,151,167) | (859,785) |
| Additions to field service assets | (3,056) | (5,915) |
| Acreage purchases | (175,041) | (151,118) |
| Proceeds from disposal of assets | 32,082 | 40,264 |
| Purchase of marketable securities held by the deferred compensation plan | (33,997) | (15,626) |
| Proceeds from the sales of marketable securities held by the deferred compensation plan | 21,485 | 8,452 |
| Net cash used in investing activities from continuing operations | (1,309,694) | (983,728) |
| Net cash provided from investing activities from discontinued operations | | 840,723 |
| Net cash used in investing activities | (1,309,694) | (143,005) |
| **Financing activities:** | | |
| Borrowing on credit facilities | 1,139,000 | 490,826 |
| Repayment on credit facilities | (865,000) | (764,826) |
| Issuance of subordinated notes | 600,000 | 500,000 |
| Repayment of subordinated notes | | (413,698) |
| Dividends paid | (19,475) | (19,305) |

| | | |
|---|---|---|
| Debt issuance costs | (12,606) | (22,003) |
| Issuance of common stock | 2,073 | 585 |
| Change in cash overdrafts | (15,750) | (39,761) |
| Proceeds from the sales of common stock held by the deferred compensation plan | 20,388 | 11,878 |
| Net cash provided from (used in) financing activities | 848,630 | (256,304) |
| **Increase in cash and cash equivalents** | 59 | 49,036 |
| **Cash and cash equivalents at beginning of period** | 92 | 2,848 |
| **Cash and cash equivalents at end of period** | $ 151 | $ 51,884 |

**See the accompanying notes.**

4

**RANGE RESOURCES CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)**

**(1) SUMMARY OF ORGANIZATION AND NATURE OF BUSINESS**

Range Resources Corporation ( Range, we, us, or our ) is a Fort Worth, Texas-based independent natural gas, natural gas liquids ( NGLs ) and company primarily engaged in the exploration, development and acquisition of natural gas and oil properties in the Appalachian and Southwestern regions of the United States. Our objective is to build stockholder value through consistent growth in reserves and production on a cost-efficient basis. Range is a Delaware corporation with our common stock listed and traded on the New York Stock Exchange under the symbol RRC.

**(2) BASIS OF PRESENTATION**

**Presentation**

These interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Range Resources Corporation 2011 Annual Report on Form 10-K filed on February 22, 2012, as amended by the Form 10-K/A filed on February 23, 2012. The results of operations for the quarter and the nine months ended September 30, 2012 are not necessarily indicative of the results to be expected for the full year. These consolidated financial statements are unaudited but, in the opinion of management, reflect all adjustments necessary for fair presentation of the results for the periods presented. All adjustments are of a normal recurring nature unless otherwise disclosed. These consolidated financial statements, including selected notes, have been prepared in accordance with the applicable rules of the Securities and Exchange Commission ( SEC ) and do not include all of the information and disclosures required by accounting principles generally accepted in the United States of America ( U.S. GAAP ) for complete financial statements. Certain reclassifications have been made to prior year s reported amounts in order to conform with the current year presentation. These reclassifications include third party transportation and gathering costs which were previously reflected as a component of natural gas, NGL and oil sales and are currently reported as a separate operating expense. These reclassifications have no impact on previously reported net income.

In first quarter 2012, the Pennsylvania legislature passed an impact fee on unconventional natural gas and oil production. The impact fee is a per well annual fee imposed for a period of fifteen years on all unconventional wells drilled in Pennsylvania. The fee is based on the average annual price of natural gas and the Consumer Price Index. The annual fee per well declines each year over the fifteen year time period as long as the well is producing. We have recorded in the first nine months 2012, a retroactive impact fee of $24.7 million for wells drilled during 2011 and prior. This expense is reflected in our statement of operations category production and ad valorem taxes. In second quarter 2012, we also recorded a $23.1 million abandonment and impairment expense related to a transaction involving individually significant unproved leases in two Pennsylvania counties where we do not expect to drill. In third quarter 2012, we recorded a $19.6 million abandonment and impairment expense related to individually significant unproved leases in the North Texas Barnett Shale where we also do not expect to drill.

**Discontinued Operations**

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

**(3) NEW ACCOUNTING STANDARDS**

In May 2011, the Financial Accounting Standards Board ( FASB ) issued ASU No. 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS. This pronouncement was issued to provide a consistent definition of fair value and ensure that the fair value measurement and disclosure requirements are similar between U.S. GAAP and International Financial Reporting Standards. ASU 2011-04 changes certain fair value measurement principles and enhances the disclosure requirements, particularly for Level 3 fair value measurements. This pronouncement is effective for reporting periods beginning on or after December 15, 2011, with early adoption prohibited. The new guidance requires prospective application. We adopted this new requirement in first quarter 2012 and it did not have a material effect on our consolidated financial statements.

Table of Contents

In December 2011, the FASB issued ASU No. 2011-11, Disclosures about Offsetting Assets and Liabilities requiring additional disclosures about offsetting and related arrangements. ASU 2011-11 is effective retrospectively for annual reporting periods beginning on or after January 1, 2013. The adoption of ASU 2011-11 is not expected to impact our future financial position, results of operation or liquidity.

**(4) DISPOSITIONS**

**2012 Dispositions**

In September 2012, we sold unproved properties in three counties in Pennsylvania for proceeds of $13.9 million resulting in a pre-tax gain of $746,000. As part of this agreement, we retained an overriding royalty of 1% to 5% on a large portion of the leases. In June 2012, we sold a suspended exploratory well in the Marcellus Shale for proceeds of $2.5 million resulting in a pre-tax loss of $2.5 million. In March 2012, we sold seventy-five percent of a prospect in East Texas which included unproved properties and a suspended exploratory well to a third party for $8.6 million resulting in a pre-tax loss of $10.9 million. As part of this agreement, we retained a carried interest on the first well drilled and an overriding royalty of 2.5% to 5.0% in the prospect.

On October 9, 2012, we signed a definitive agreement to sell certain of our oil and gas properties in southern Oklahoma which includes approximately 45 producing wells for a purchase price of $135.0 million, subject to normal post-closing adjustments. The completion of the sale is dependent on prospective buyer due diligence procedures and there can be no assurance the sale will be completed or that there will not be changes to the sales price. We currently expect the closing date to be on November 19, 2012.

**2011 Dispositions**

In third quarter 2011, we sold various producing properties in East Texas for proceeds of $10.5 million. We recognized an impairment charge of $31.2 million in third quarter 2011 related to these properties. For more information on this impairment charge, see Note 13. Also in third quarter 2011, we sold producing properties in Pennsylvania for proceeds of $5.4 million, with no gain or loss recognized, as the sale did not materially impact the depletion rate of the remaining properties in the amortization base.

In February 2011, we entered into an agreement to sell substantially all of our Barnett Shale properties located in North Central Texas (Dallas, Denton, Ellis, Hill, Hood, Johnson, Parker, Tarrant and Wise Counties), which was subject to normal post-closing adjustments. We closed substantially all of this sale in April 2011 and closed the remainder in August 2011. The gross cash proceeds were approximately $889.3 million, including certain derivative contracts assumed by the buyer. The agreements had a February 1, 2011 effective date and consequently operating net revenues after January 2011 were a downward adjustment to the sales price. As indicated in Notes 2 and 5, the historic results of our Barnett Shale operations are presented as discontinued operations. In first quarter 2011, we also sold a low pressure pipeline for $14.7 million in proceeds, with no gain or loss recognized.

Also as part of the sale of our Barnett Shale properties, certain derivative contracts were assumed by the buyer. This resulted in a loss of $1.7 million in second quarter 2011, which is included in continuing operations. The hedges assumed as part of the sale were not designated to our Barnett production.

Table of Contents

**(5) DISCONTINUED OPERATIONS**

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

| | Three Months Ended September 30, 2011 | Nine Months Ended September 30, 2011 |
|---|---|---|
| **Revenues and other income:** | | |
| Natural gas, NGLs and oil sales | $ 1,673 | $ 58,997 |
| Other | | 10 |
| Gain on the sale of assets | 1,032 | 4,852 |
| Total revenues and other income | 2,705 | 63,859 |
| **Costs and expenses:** | | |
| Direct operating | (611) | 9,835 |
| Transportation, gathering and compression | 950 | 5,240 |
| Production and ad valorem taxes | (44) | 1,206 |
| Exploration expense | | 37 |
| Interest expense [a] | | 14,791 |
| Depletion, depreciation and amortization | | 8,894 |
| Total costs and expenses | 295 | 40,003 |
| **Income before income taxes** | 2,410 | 23,856 |
| Income tax expense | | |
| Current | | |
| Deferred | 841 | 8,372 |
| | 841 | 8,372 |
| **Net income from discontinued operations** | $ 1,569 | $ 15,484 |

[a] Interest expense is allocated to discontinued operations based on the ratio of net assets of discontinued operations to our consolidated net assets plus long-term debt.

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

| | December 31, 2011 |
|---|---|
| **Composition of liabilities of discontinued operations:** | |
| Accrued liabilities | $ 653 |
| Total current liabilities of discontinued operations | $ 653 |

**(6) INCOME TAXES**

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| Income tax (benefit) expense | $ (29,074) | $ 22,540 | $ (17,910) | $ 35,346 |
| Effective tax rate | 35.1% | 40.4% | 30.9% | 43.7% |

7

We compute our quarterly taxes under the effective tax rate method based on applying an anticipated annual effective rate to our year-to-date income, except for discrete items. Income taxes for discrete items are computed and recorded in the period that the specific transaction occurs. For third quarter and nine months ended September 30, 2012 and 2011, our overall effective tax rate on pre-tax income from continuing operations was different than the statutory rate of 35% due primarily to state income taxes, valuation allowances and other permanent differences.

**(7) INCOME (LOSS) PER COMMON SHARE**

Basic income or loss per share attributable to common shareholders is computed as (1) income or loss attributable to common shareholders (2) less income allocable to participating securities (3) divided by weighted average basic shares outstanding. Diluted income or loss per share attributable to common stockholders is computed as (1) basic income or loss attributable to common shareholders (2) plus diluted adjustments to income allocable to participating securities (3) divided by weighted average diluted shares outstanding. The following tables set forth a reconciliation of income or loss attributable to common shareholders to basic income or loss attributable to common shareholders and to diluted income or loss attributable to common shareholders (in thousands except per share amounts):

| | Three Months Ended September 30, 2012 | | | Three Months Ended September 30, 2011 | | |
|---|---|---|---|---|---|---|
| | Continuing Operations | Discontinued Operations | Total | Continuing Operations | Discontinued Operations | Total |
| (Loss) income as reported | $ (53,836) | $ | $ (53,836) | $ 33,186 | $ 1,569 | $ 34,755 |
| Participating basic earnings [a] | (119) | | (119) | (585) | (28) | (613) |
| Basic (loss) income attributed to common shareholders | (53,955) | | (53,955) | 32,601 | 1,541 | 34,142 |
| Reallocation of participating earnings [a] | | | | 3 | | 3 |
| Diluted (loss) income attributed to common shareholders | $ (53,955) | $ | $ (53,955) | $ 32,604 | $ 1,541 | $ 34,145 |
| (Loss) income per common share: | | | | | | |
| Basic | $ (0.34) | $ | $ (0.34) | $ 0.21 | $ 0.01 | $ 0.22 |
| Diluted | $ (0.34) | $ | $ (0.34) | $ 0.20 | $ 0.01 | $ 0.21 |

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

| | Nine Months Ended September 30, 2012 | | | Nine Months Ended September 30, 2011 | | |
|---|---|---|---|---|---|---|
| | Continuing Operations | Discontinued Operations | Total | Continuing Operations | Discontinued Operations | Total |
| (Loss) income as reported | $ (39,960) | $ | $ (39,960) | $ 45,531 | $ 15,484 | $ 61,015 |
| Participating basic earnings [a] | (348) | | (348) | (818) | (278) | (1,096) |
| Basic (loss) income attributed to common shareholders | (40,308) | | (40,308) | 44,713 | 15,206 | 59,919 |
| Reallocation of participating earnings [a] | | | | 3 | 2 | 5 |
| Diluted (loss) income attributed to common shareholders | $ (40,308) | $ | $ (40,308) | $ 44,716 | $ 15,208 | $ 59,924 |

| | | | | | | |
|---|---|---|---|---|---|---|
| (Loss) income per common share: | | | | | | |
| Basic | $ (0.25) | $ | $ (0.25) | $ 0.28 | $ 0.10 | $ 0.38 |
| Diluted | $ (0.25) | $ | $ (0.25) | $ 0.28 | $ 0.10 | $ 0.38 |

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

Table of Contents

The following table provides a reconciliation of basic weighted average common shares outstanding to diluted weighted average common shares outstanding (in thousands):

| | Three Months Ended September 30, 2012 | Three Months Ended September 30, 2011 | Nine Months Ended September 30, 2012 | Nine Months Ended September 30, 2011 |
|---|---|---|---|---|
| Denominator: | | | | |
| Weighted average common shares outstanding basic | 159,563 | 158,154 | 159,297 | 157,901 |
| Effect of dilutive securities: | | | | |
| Director and employee stock options and SARs | | 1,168 | | 1,038 |
| Weighted average common shares outstanding diluted | 159,563 | 159,322 | 159,297 | 158,939 |

Weighted average common shares basic for the three months ended September 30, 2012 excludes 3.0 million shares and the three months ended September 30, 2011 excludes 2.9 million shares of restricted stock held in our deferred compensation plans (although all awards are issued and outstanding upon grant). Weighted average common shares-basic for the nine months ended September 30, 2012 and 2011 excludes 2.9 million shares of restricted stock. Due to our loss from continuing operations for the three months and the nine months ended September 30, 2012, we excluded all outstanding stock options, stock appreciation rights ( SARs ) and restricted stock from the computations of diluted net income per share because the effect would have been anti-dilutive to the computations. SARs of 347,000 for the three months ended September 30, 2011 and 855,000 for the nine months ended September 30, 2011 were outstanding but not included in the computations of diluted income from continuing operations per share because the grant prices of the SARs were greater than the average market price of the common shares.

**(8) SUSPENDED EXPLORATORY WELL COSTS**

We capitalize exploratory well costs until a determination is made that the well has either found proved reserves or that it is impaired. Capitalized exploratory well costs are presented in natural gas and oil properties in the accompanying consolidated balance sheets. If an exploratory well is determined to be impaired, the well costs are charged to exploration expense in the accompanying consolidated statements of operations. The following table reflects the changes in capitalized exploratory well costs for the nine months ended September 30, 2012 and the year ended December 31, 2011 (in thousands except for number of projects):

| | September 30, 2012 | December 31, 2011 |
|---|---|---|
| Balance at beginning of period | $ 93,388 | $ 23,908 |
| Additions to capitalized exploratory well costs pending the determination of proved reserves | 186,087 | 86,996 |
| Reclassifications to wells, facilities and equipment based on determination of proved reserves | (178,422) | (17,516) |
| Divested wells | (4,980) | |
| Balance at end of period | 96,073 | 93,388 |
| Less exploratory well costs that have been capitalized for a period of one year or less | (74,269) | (83,860) |
| Capitalized exploratory well costs that have been capitalized for a period greater than one year | $ 21,804 | $ 9,528 |
| Number of projects that have exploratory well costs that have been capitalized for a period greater than one year | 8 | 3 |

Table of Contents

As of September 30, 2012, $21.8 million of capitalized exploratory well costs have been capitalized for more than one year with five of the wells waiting on pipelines and three of the wells currently in the completion stage. Seven of the wells are located in our Marcellus Shale area. In second quarter 2012, we sold a Marcellus Shale exploratory well. In first quarter 2012, we sold a seventy-five percent interest in an East Texas exploratory well. For additional information, see Note 4. The following table provides an aging of capitalized exploratory well costs that have been suspended for more than one year as of September 30, 2012 (in thousands):

| | Total | 2012 | 2011 | 2010 | 2009 | 2008 |
|---|---|---|---|---|---|---|
| Capitalized exploratory well costs that have been capitalized for more than one year | $ 21,804 | $ 7,019 | $ 10,306 | $ 72 | $ 2,884 | $ 1,523 |

**(9) INDEBTEDNESS**

We had the following debt outstanding as of the dates shown below (in thousands) (bank debt interest rate at September 30, 2012 is shown parenthetically). No interest was capitalized during the three months or the nine months ended September 30, 2012 or 2011.

| | September 30, 2012 | December 31, 2011 |
|---|---|---|
| Bank debt (1.8%) | $ 461,000 | $ 187,000 |
| Senior subordinated notes: | | |
| 7.50% senior subordinated notes due 2017 | 250,000 | 250,000 |
| 7.25% senior subordinated notes due 2018 | 250,000 | 250,000 |
| 8.00% senior subordinated notes due 2019, net of $11,131 and $12,033 discount, respectively | 288,869 | 287,967 |
| 6.75% senior subordinated notes due 2020 | 500,000 | 500,000 |
| 5.75% senior subordinated notes due 2021 | 500,000 | 500,000 |
| 5.00% senior subordinated notes due 2022 | 600,000 | |
| Total debt | $ 2,849,869 | $ 1,974,967 |

**Bank Debt**

In February 2011, we entered into an amended and restated revolving bank facility, which we refer to as our bank debt or our bank credit facility, which is secured by substantially all of our assets. The bank credit facility provides for an initial commitment equal to the lesser of the facility amount or the borrowing base. On September 30, 2012, the facility amount was $1.75 billion and the borrowing base was $2.0 billion. The bank credit facility provides for a borrowing base subject to redeterminations semi-annually and for event-driven unscheduled redeterminations. As part of our semi-annual bank review completed on October 4, 2012, our borrowing base was reaffirmed at $2.0 billion and our facility amount was also reaffirmed at $1.75 billion. Our current bank group is comprised of twenty-eight financial institutions, with no one bank holding more than 9% of the total facility and includes three additional banks that were added in April 2012. The facility amount may be increased to the borrowing base amount with twenty days notice, subject to the banks agreeing to participate in the facility increase and payment of a mutually acceptable commitment fee to those banks. As of September 30, 2012, the outstanding balance under our bank credit facility was $461.0 million. Additionally, we had $62.1 million of undrawn letters of credit leaving $1.2 billion of borrowing capacity available under the facility amount. The facility matures on February 18, 2016. Borrowings under the bank facility can either be at the Alternate Base Rate (as defined) plus a spread ranging from 0.50% to 1.5% or LIBOR borrowings at the Adjusted LIBO Rate (as defined) plus a spread ranging from 1.5% to 2.5%. The applicable spread is dependent upon borrowings relative to the borrowing base. We may elect, from time to time, to convert all or any part of our LIBOR loans to base rate loans or to convert all or any of the base rate loans to LIBOR loans. The weighted average interest rate was 2.1% for the three months ended September 30, 2012. The weighted average interest rate was 2.2% for the nine months ended September 30, 2012 compared to 2.2% for the nine months ended September 30, 2011. A commitment fee is paid on the undrawn balance based on an annual rate of 0.375% to 0.50%. At September 30, 2012, the commitment fee was 0.375% and the interest rate margin was 1.5% on our LIBOR loans and 0.5% on our base rate loans.

**Senior Subordinated Notes**

In March 2012, we issued $600.0 million aggregate principal amount of 5.00% senior subordinated notes due 2022 (   5.00% Notes   ) for net proceeds of $589.5 million after underwriting discounts and commissions of $10.5 million. The 5.00% Notes were issued at par. Interest on the 5.00% Notes is payable semi-annually in February and August and is guaranteed by all of our subsidiary guarantors. We may redeem the 5.00% Notes, in whole or in part, at any time on or after February 15, 2017, at a redemption price of 102.5% of the principal amount as of February 15, 2017, declining to 100% on February 15, 2020 and thereafter. Before February 2015, we may redeem up to 35% of the original aggregate principal amount of the 5.00% Notes at a redemption price equal to 105% of the principal amount thereof, plus accrued and unpaid interest, if any, with the proceeds of certain equity offerings, provided that 65% of the aggregate principal amount of 5.00% Notes remains outstanding immediately after the occurrence of such redemption and also provided such redemption shall occur within 60 days of the date of the closing of the equity offering. On closing of the 5.00% Notes, we used $350.0 million of the proceeds to pay down our outstanding credit facility balance.

If we experience a change of control, bondholders may require us to repurchase all or a portion of all of our senior subordinated notes at 101% of the aggregate 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 subordinated notes.

**Guarantees**

Range Resources Corporation is a holding company which owns no operating assets and has no significant operations independent of its subsidiaries. The guarantees by our subsidiaries of our senior subordinated notes are full and unconditional and joint and several.

**Debt Covenants and Maturity**

Our bank credit facility contains negative covenants that limit our ability, among other things, to pay cash dividends, incur additional indebtedness, sell assets, enter into certain hedging contracts, change the nature of our business or operations, merge, consolidate, or make investments. In addition, we are required to maintain a ratio of debt to EBITDAX (as defined in the credit agreement) of no greater than 4.25 to 1.0 and a current ratio (as defined in the credit agreement) of no less than 1.0 to 1.0. We were in compliance with our covenants under the bank credit facility at September 30, 2012.

The indentures governing our senior subordinated notes contain various restrictive covenants that are substantially identical to each other and may limit our ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, enter into transactions with affiliates, or change the nature of our business. At September 30, 2012, we were in compliance with these covenants.

## (10) ASSET RETIREMENT OBLIGATIONS

Our asset retirement obligations primarily represent the estimated present value of the amounts we will incur to plug, abandon and remediate our producing properties at the end of their productive lives. Significant inputs used in determining such obligations include estimates of plugging and abandonment costs, estimated future inflation rates and well life. The inputs are calculated based on historical data as well as current estimated costs. A reconciliation of our liability for plugging and abandonment costs for the first nine months 2012 is as follows (in thousands):

| | Nine Months Ended September 30, 2012 |
|---|---|
| Beginning of period | $ 84,810 |
| Liabilities incurred | 7,400 |
| Liabilities settled | (3,073) |
| Disposition of wells | (1,286) |
| Accretion expense | 6,444 |
| Change in estimate | 22,295 |
| End of period | 116,590 |
| Less current portion | (5,005) |

| | | |
|---|---|---|
| Long-term asset retirement obligations | $ | 111,585 |

11

Table of Contents

Accretion expense is recognized as a component of depreciation, depletion and amortization expense in the accompanying statements of operations.

### (11) CAPITAL STOCK

We have authorized capital stock of 485.0 million shares which includes 475.0 million shares of common stock and 10.0 million shares of preferred stock. We currently have no preferred stock issued or outstanding. The following is a schedule of changes in the number of common shares outstanding since the beginning of 2011:

| | Nine Months Ended September 30, 2012 | Year Ended December 31, 2011 |
|---|---|---|
| Beginning balance | 161,131,547 | 159,909,052 |
| Stock options/SARs exercised | 878,963 | 862,774 |
| Restricted stock granted | 354,674 | 326,591 |
| Restricted stock units vested | 55,588 | |
| Treasury shares issued | 40,268 | 33,130 |
| Ending balance | 162,461,040 | 161,131,547 |

### (12) DERIVATIVE ACTIVITIES

We use commodity-based derivative contracts to manage exposure to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. We do not utilize complex derivatives as we typically utilize commodity swap, collar, call or put option contracts to (1) reduce the effect of price volatility of the commodities we produce and sell and (2) support our annual capital budget and expenditure plans. In 2011, we sold NGLs derivative swap contracts ( sold swaps ) for the natural gasoline (or C5) component of natural gas liquids and in 2012, we also entered into purchased derivative swaps ( purchased swaps ) for C5 volumes. These purchased swaps were, in some cases, with the same counterparties as our sold swaps. We entered into these purchased swaps to lock in certain natural gasoline derivative gains. In second quarter 2012, we also entered into NGL derivative swap contracts for the propane (or C3) component of NGLs. At September 30, 2012, we had open swap contracts covering 89.6 Bcf of natural gas at prices averaging $3.62 per mcf, 3.3 million barrels of oil at prices averaging $95.70 per barrel, 3.0 million net barrels of NGLs (the C5 component of NGLs) at prices averaging $95.80 per barrel and 2.4 million barrels of NGLs (the C3 component of NGLs) at prices averaging $36.27 per barrel. At September 30, 2012, we had collars covering 232.0 Bcf of natural gas at weighted average floor and cap prices of $4.23 to $4.83 per mcf and 2.0 million barrels of oil at weighted average floor and cap prices of $86.88 to $98.17 per barrel. At September 30, 2012, we also had sold call options for 0.4 million barrels of oil at a weighted average price of $85.00 per barrel and purchased put options for 0.2 million barrels of oil at a weighted average price of $80.00 per barrel. The fair value of these contracts, represented by the estimated amount that would be realized upon termination, based on a comparison of the contract price and a reference price, generally the New York Mercantile Exchange ( NYMEX ), approximated a net unrealized pre-tax gain of $139.3 million at September 30, 2012. These contracts expire monthly through December 2014. The following table sets forth our derivative volumes by year as of September 30, 2012.

| Period | Contract Type | Volume Hedged | Weighted Average Hedge Price |
|---|---|---|---|
| Natural Gas | | | |
| 2012 | Collars | 279,641 Mmbtu/day | $ 4.76 $ 5.22 |
| 2013 | Collars | 240,000 Mmbtu/day | $ 4.73 $ 5.20 |
| 2014 | Collars | 325,000 Mmbtu/day | $ 3.75 $ 4.47 |
| 2012 | Swaps | 270,000 Mmbtu/day | $3.77 |
| 2013 | Swaps | 177,521 Mmbtu/day | $3.57 |
| Crude Oil | | | |
| 2012 | Collars | 2,000 bbls/day | $ 70.00 $ 80.00 |
| 2013 | Collars | 3,000 bbls/day | $ 90.60 $ 100.00 |
| 2014 | Collars | 2,000 bbls/day | $ 85.55 $ 100.00 |
| 2012 | Call Options | 4,700 bbls/day | $85.00 |
| 2012 | Put Options | 2,500 bbls/day | $80.00 |
| 2013 | Swaps | 5,081 bbls/day | $96.59 |
| 2014 | Swaps | 4,000 bbls/day | $94.56 |
| NGLs (Natural Gasoline) | | | |
| 2012 | Sold Swaps | 12,000 bbls/day | $96.28 |
| 2013 | Sold Swaps | 8,000 bbls/day | $89.64 |
| 2012 | Purchased Swaps | 5,500 bbls/day | $82.37 |
| 2013 | Purchased Swaps | 1,500 bbls/day | $76.30 |
| NGLs (Propane) | | | |
| 2012 | Swaps | 6,000 bbls/day | $38.67 |
| 2013 | Swaps | 5,000 bbls/day | $35.55 |

Every derivative instrument is required to be recorded on the balance sheet as either an asset or a liability measured at its fair value. Fair value is determined based on the difference between the fixed contract price and the underlying market price at the determination date. Changes in the fair value of our derivatives that qualify for hedge accounting are recorded as a component of accumulated other comprehensive income ( AOCI ) in the stockholders equity section of the accompanying consolidated balance sheets, which is later transferred to natural gas, NGLs and oil sales when the underlying physical transaction occurs and the hedging contract is settled. As of September 30, 2012, an unrealized pre-tax derivative gain of $110.3 million was recorded in AOCI. This gain will be reclassified into earnings as a gain of $43.4 million in fourth quarter 2012, a gain of $71.8 million in 2013 and a loss of $4.9 million in 2014 as the contracts settle. The actual reclassification to earnings will be based on market prices at the contract settlement date. If the derivative does not qualify as a hedge or is not designated as a hedge, changes in fair value of these non-hedge derivatives are recognized in earnings in derivative fair value income (loss).

For those derivative instruments that qualify for hedge accounting, settled transaction gains and losses are determined monthly, and are included as increases or decreases to natural gas, NGLs and oil sales in the period the hedged production is sold. Through September 2012, we have elected to designate our commodity derivative instruments that qualify for hedge accounting as cash flow hedges. Natural gas, NGLs and oil sales include $61.5 million of gains in third quarter 2012 compared to gains of $26.8 million in the same period of 2011 related to settled hedging transactions. Natural gas, NGLs and oil sales include $197.7 million of gains in the first nine months 2012 compared to $80.7 million in the same period of 2011. Any ineffectiveness associated with these hedge derivatives are reflected in derivative fair value income (loss) in the accompanying statements of operations. The ineffective portion is generally calculated as the difference between the changes in fair value of the derivative and the estimated change in future cash flows from the item hedged. Derivative fair value income (loss) for the three months ended September 30, 2012 includes ineffective losses (unrealized and realized) of $3.7 million compared to a loss of $1.9 million in the three months ended September 30, 2011. Derivative fair value income (loss) for the nine months ended September 30, 2012 includes ineffective losses (unrealized and realized) of $1.6 million compared to gains of $7.1 million in the same period of 2011.

Table of Contents

**Derivative fair value (loss) income**

The following table presents information about the components of derivative fair value (loss) income for the three months and the nine months ended September 30, 2012 and 2011 (in thousands):

| | Three Months Ended September 30, 2012 | Three Months Ended September 30, 2011 | Nine Months Ended September 30, 2012 | Nine Months Ended September 30, 2011 |
|---|---|---|---|---|
| Change in fair value of derivatives that do not qualify for hedge accounting [a] | $ (53,646) | $ 58,990 | $ 30,075 | $ 67,093 |
| Realized gain (loss) on settlement natural gas [a] [b] | | 5,334 | | 8,424 |
| Realized gain (loss) on settlement oil [a] [b] | 1,955 | 285 | (1,899) | (7,727) |
| Realized gain (loss) on settlement NGLs [a] [b] | 14,682 | 3,087 | 20,442 | 3,087 |
| Hedge ineffectiveness realized | 988 | 2,036 | 3,451 | 4,558 |
| unrealized | (4,707) | (3,971) | (5,061) | 2,531 |
| Derivative fair value (loss) income | $ (40,728) | $ 65,761 | $ 47,008 | $ 77,966 |

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

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

**Derivative assets and liabilities**

The combined fair value of derivatives included in the accompanying consolidated balance sheets as of September 30, 2012 and December 31, 2011 is summarized below (in thousands). As of September 30, 2012, we are conducting derivative activities with sixteen financial institutions, of which all but two are secured lenders in our bank credit facility. We believe all of these institutions are acceptable credit risks. At times, such risks may be concentrated with certain counterparties. The credit worthiness of our counterparties is subject to periodic review. The assets and liabilities are netted where derivatives with both gain and loss positions are held by a single counterparty and we have master netting arrangements.

| | September 30, 2012 | December 31, 2011 |
|---|---|---|
| Derivative assets: | | |
| Natural gas swaps | $ (2,922) | $ 54,162 |
| collars | 116,531 | 228,228 |
| Crude oil swaps | 9,848 | (263) |
| collars | (1,441) | (16,607) |
| call options | (3,733) | (29,348) |
| put options | 46 | |
| NGLs C5 swaps | 33,864 | 15,328 |
| C3 swaps | 296 | |
| | $ 152,489 | $ 251,500 |
| Derivative liabilities: | | |
| Natural gas swaps | $ (2,764) | $ |

| | | | |
|---|---|---|---|
| | collars | (5,603) | |
| Crude oil | collars | 141 | |
| | put options | 31 | |
| NGLs | C5 swaps | 2,378 | (173) |
| | C3 swaps | (7,416) | |
| | | $ (13,233) | $ (173) |

**Table of Contents**

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

| | September 30, 2012 | | | December 31, 2011 | | |
|---|---|---|---|---|---|---|
| | Assets Carrying Value | (Liabilities) Carrying Value | Net Carrying Value | Assets Carrying Value | (Liabilities) Carrying Value | Net Carrying Value |
| Derivatives that qualify for cash flow hedge accounting : | | | | | | |
| Swaps [(a)] | $ 24,344 | $ (20,184) | $ 4,160 | $ 54,318 | $ (419) | $ 53,899 |
| Collars [(a)] | 130,842 | (18,816) | 112,026 | 228,228 | (1,954) | 226,274 |
| Put options [(a)] | 77 | | 77 | | | |
| | $ 155,263 | $ (39,000) | $ 116,263 | $ 282,546 | $ (2,373) | $ 280,173 |
| Derivatives that do not qualify for hedge accounting : | | | | | | |
| Sold swaps [(a)] | $ 31,933 | $ (7,594) | $ 24,339 | $ 17,949 | $ (2,794) | $ 15,155 |
| Purchased swaps [(a)] | 5,571 | (788) | 4,783 | | | |
| Collars [(a)] | | (2,396) | (2,396) | | (14,653) | (14,653) |
| Call options [(a)] | | (3,733) | (3,733) | | (29,348) | (29,348) |
| | $ 37,504 | $ (14,511) | $ 22,993 | $ 17,949 | $ (46,795) | $ (28,846) |

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

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

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | Change in Hedge Derivative Fair Value | | Realized Gain (Loss) Reclassified from OCI into Revenue (a) | | Change in Hedge Derivative Fair Value | | Realized Gain (Loss) Reclassified from OCI into Revenue (a) | |
| | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 |
| Swaps | $ (33,311) | $ 15,739 | $ 18,204 | $ | $ 22,525 | $ 17,854 | $ 69,851 | $ |
| Put options | (994) | | (682) | | (1,908) | | (998) | |
| Collars | (51,344) | 75,449 | 43,945 | 26,758 | 32,704 | 97,873 | 128,823 | 80,660 |
| Collars discontinued operations | | | | | | 412 | | 8,607 |
| Income taxes | 33,403 | (34,195) | (23,972) | (10,034) | (21,780) | (41,609) | (76,805) | (33,476) |
| | $ (52,246) | $ 56,993 | $ 37,495 | $ 16,724 | $ 31,541 | $ 74,530 | $ 120,871 | $ 55,791 |

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

15

**Table of Contents**

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

| | Three Months Ended September 30, | | | | | |
|---|---|---|---|---|---|---|
| | Gain (Loss) Recognized in Income (Non-hedge Derivatives) | | Gain (Loss) Recognized in Income (Ineffective Portion) | | Derivative Fair Value Income (Loss) | |
| | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 |
| Swaps | $ (45,998) | $ 26,219 | $ (1,556) | $ | $ (47,554) | $ 26,219 |
| Purchased swaps | 12,822 | | | | 12,822 | |
| Collars | (1,714) | 15,828 | (2,163) | (1,935) | (3,877) | 13,893 |
| Call options | (2,119) | 25,649 | | | (2,119) | 25,649 |
| Total | $ (37,009) | $ 67,696 | $ (3,719) | $ (1,935) | $ (40,728) | $ 65,761 |

| | Nine Months Ended September 30, | | | | | |
|---|---|---|---|---|---|---|
| | Gain (Loss) Recognized in Income (Non-hedge Derivatives) | | Gain (Loss) Recognized in Income (Ineffective Portion) | | Derivative Fair Value Income (Loss) | |
| | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 |
| Swaps | $ 30,330 | $ 39,968 | $ (890) | $ | $ 29,440 | $ 39,968 |
| Purchased swaps | 4,078 | | | | 4,078 | |
| Collars | 3,381 | 14,693 | (720) | 7,089 | 2,661 | 21,782 |
| Call options | 10,829 | 16,259 | | | 10,829 | 16,259 |
| Basis swaps | | (43) | | | | (43) |
| Total | $ 48,618 | $ 70,877 | $ (1,610) | $ 7,089 | $ 47,008 | $ 77,966 |

The United States Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as Range, that participate in that market. The new regulation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act required the Commodities Futures Trading Commission (the CFTC ) and the SEC to promulgate rules and regulations implementing the new legislation. In July 2012 certain definitions were adopted by the SEC and the CFTC and based on those definitions, we believe we will qualify for the end-user exception related to the clearing requirement for swaps but we will be required to adhere to new reporting requirements.

**(13) FAIR VALUE MEASUREMENTS**

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

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

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

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

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

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy.

Table of Contents

***Fair Values-Recurring***

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

| | Fair Value Measurements at September 30, 2012 using: | | | |
|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Total Carrying Value as of September 30, 2012 |
| Trading securities held in the deferred compensation plans | $ 67,429 | $ | $ | $ 67,429 |
| Derivatives swaps | | 33,282 | | 33,282 |
| collars | | 109,629 | | 109,629 |
| call options | | (3,732) | | (3,732) |
| put options | | 77 | | 77 |

| | Fair Value Measurements at December 31, 2011 using: | | | |
|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Total Carrying Value as of December 31, 2011 |
| Trading securities held in the deferred compensation plans | $ 50,237 | $ | $ | $ 50,237 |
| Derivatives swaps | | 69,054 | | 69,054 |
| collars | | 211,621 | | 211,621 |
| call options | | (29,348) | | (29,348) |

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

Our trading securities held in the deferred compensation plan are accounted for using the mark-to-market accounting method and are included in other assets in the accompanying consolidated balance sheets. We elected to adopt the fair value option to simplify our accounting for the investments in our deferred compensation plan. Interest, dividends, and mark-to-market gains or losses are included in deferred compensation plan expense in the accompanying statement of operations. For third quarter 2012, interest and dividends were $122,000 and the mark-to-market adjustment was a gain of $3.8 million. For third quarter 2011, interest and dividends were $84,000 and the mark-to-market adjustment was a loss of $7.9 million. For the nine months ended September 30, 2012, interest and dividends were $279,000 and the mark-to-market adjustment was a gain of $5.7 million. For the nine months ended September 30, 2011, interest and dividends were $179,000 and the mark-to-market adjustment was a loss of $6.6 million.

***Fair Values-Nonrecurring***

We review our long-lived assets to be held and used, including proved natural gas and oil properties, whenever events or circumstances indicate the carrying value of those assets may not be recoverable. In third quarter 2012, we evaluated certain surface property we own which included a consideration for the potential sale of these assets. As a result, we recognized an impairment charge of $1.3 million.

Several long-lived assets held for use were evaluated for impairment during 2011 due to reductions in estimated reserves and lower natural gas prices. The fair value of our onshore Gulf Coast assets in 2011 was measured using an income approach based upon internal estimates of future production levels, prices, drilling and operating costs and discount rates, which are Level 3 inputs. Our projected undiscounted cash flows associated with these assets was less than their carrying value and therefore, we recorded an impairment of $7.5 million in third quarter 2011 related to our onshore Gulf Coast proved properties.

Table of Contents

Also during third quarter 2011, we evaluated our East Texas properties for impairment which included a consideration for the potential sale of some of these assets, along with a reduction in estimated reserves and lower natural gas prices. This analysis reflected undiscounted cash flows for these properties was less than their carrying value and we recognized an impairment charge of $31.2 million. Some of these properties were sold in third quarter 2011 for proceeds of $10.5 million.

The following table presents the value of these assets measured at fair value on a nonrecurring basis (in thousands). All such fair value measurements represent Level 3 measurements.

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2012 | | 2011 | | 2012 | | 2011 | |
| | Fair Value | Impairment | Fair Value | Impairment | Fair Value | Impairment | Fair Value | Impairment |
| Surface property | $ 6,269 | $ 1,281 | $ | $ | $ 6,269 | $ 1,281 | $ | $ |
| Natural gas and oil properties | $ | $ | $ 24,388 | $ 38,681 | $ | $ | $ 24,388 | $ 38,681 |

***Fair Values Reported***

The following table presents the carrying amounts and the fair values of our financial instruments as of September 30, 2012 and December 31, 2011 (in thousands):

| | September 30, 2012 | | December 31, 2011 | |
|---|---|---|---|---|
| | Carrying Value | Fair Value | Carrying Value | Fair Value |
| Assets: | | | | |
| Commodity swaps, collars, call and put options | $ 152,489 | $ 152,489 | $ 251,500 | $ 251,500 |
| Marketable securities[a] | 67,429 | 67,429 | 50,237 | 50,237 |
| Liabilities: | | | | |
| Commodity swaps, collars, call and put options | (13,233) | (13,233) | (173) | (173) |
| Bank credit facility[b] | (461,000) | (461,000) | (187,000) | (187,000) |
| 7.50% senior subordinated notes due 2017[b] | (250,000) | (260,000) | (250,000) | (265,625) |
| 7.25% senior subordinated notes due 2018[b] | (250,000) | (264,375) | (250,000) | (267,500) |
| 8.00% senior subordinated notes due 2019[b] | (288,869) | (333,000) | (287,967) | (334,500) |
| 6.75% senior subordinated notes due 2020[b] | (500,000) | (550,000) | (500,000) | (555,000) |
| 5.75% senior subordinated notes due 2021[b] | (500,000) | (537,500) | (500,000) | (541,250) |
| 5.00% senior subordinated notes due 2022[b] | (600,000) | (633,000) | | |

(a) Marketable securities, which are held in our deferred compensation plans, and are actively traded on major exchanges.
(b) The book value of our bank debt approximates fair value because of its floating rate structure. The fair value of our senior subordinated notes is based on end of period market quotes which are Level 2 market values.

Our current assets and liabilities contain financial instruments, the most significant of which are trade accounts receivables and payables. We believe the carrying values of our current assets and liabilities approximate fair value. Our fair value assessment incorporates a variety of considerations, including (1) the short-term duration of the instruments and (2) our historical incurrence of and expected future insignificance of bad debt expense.

**Concentrations of Credit Risk**

As of September 30, 2012, our primary concentrations of credit risk are the risks of collecting accounts receivable and the risk of counterparties failure to perform under derivative obligations. Most of our receivables are from a diverse group of companies, including major energy companies, pipeline companies, local distribution companies, financial institutions and end-users in various industries. Letters of credit or other appropriate security are obtained as necessary to limit our risk of loss. Our allowance for uncollectible receivables was $1.6 million at September 30, 2012 compared to $4.0 million at December 31, 2011. As of September 30, 2012, our derivative contracts consist of swaps, collars, call options and put options. Our exposure is diversified primarily among major investment grade financial institutions, the majority of which we have master netting agreements which provide for offsetting payables against receivables from separate derivative contracts. To manage

18

counterparty risk associated with our derivatives, we select and monitor our counterparties based on our assessment of their financial strength and/or credit ratings. We may also limit the level of exposure with any single counterparty. At September 30, 2012 our derivative counterparties include sixteen financial institutions, of which all but two are secured lenders in our bank credit facility. At September 30, 2012, our net derivative assets include a receivable from the two counterparties not included in our bank credit facility of $12.7 million. For those counterparties that are not secured lenders in our bank credit facility or for which we do not have master netting arrangements, net derivative asset values are determined, in part, by reviewing credit default swap spreads for the counterparties. Net derivative liabilities are determined, in part, by using our market-based credit spread. None of our derivative contracts have margin requirements or collateral provisions that would require funding prior to the scheduled cash settlement date. We have also entered into the International Swaps and Derivatives Association Master Agreements ( ISDA Agreements ) with our counterparties. The terms of the ISDA Agreements provide us and our counterparties with rights of set off upon the occurrence of defined acts of default by either us or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party.

## (14) STOCK-BASED COMPENSATION PLANS

### Stock-Based Awards

Stock options represent the right to purchase shares of stock in the future at the fair value of the stock on the date of grant. Most stock options granted under our stock option plans vest over a three-year period and expire five years from the date they are granted. Beginning in 2005, we began granting SARs to reduce the dilutive impact of our equity plans. Similar to stock options, SARs represent the right to receive a payment equal to the excess of the fair market value of shares of common stock on the date the right is exercised over the value of the stock on the date of grant. All SARs granted under the 2005 Plan will be settled in shares of stock, vest over a three-year period and have a maximum term of five years from the date they are granted. Beginning in first quarter 2011, the Compensation Committee also began granting restricted stock units under our equity-based stock compensation plans. These restricted stock units, which we refer to as restricted stock Equity Awards, vest over a three-year period. All awards granted have been issued at prevailing market prices at the time of grant and the vesting of these shares is based upon an employee s continued employment with us.

The Compensation Committee also grants restricted stock to certain employees and non-employee directors of the Board of Directors as part of their compensation. Compensation expense is recognized over the balance of the vesting period, which is typically three years for employee grants and immediate vesting for non-employee directors. All restricted stock awards are issued at prevailing market prices at the time of the grant and vesting is based upon an employee s continued employment with us. Prior to vesting, all restricted stock awards have the right to vote such stock and receive dividends thereon. Upon grant of these restricted shares, which we refer to as restricted stock Liability Awards, the shares are placed in our deferred compensation plan and, upon vesting, employees are allowed to take withdrawals either in cash or in stock. These Liability Awards are classified as a liability and are remeasured at fair value each reporting period. This mark-to-market adjustment is reported in deferred compensation plan expense in the accompanying consolidated statements of operations.

### Total Stock-Based Compensation Expense

Stock-based compensation represents amortization of restricted stock grants and SARs expense. In third quarter 2012, stock-based compensation was allocated to operating expense ($598,000), exploration expense ($1.1 million) and general and administrative expense ($10.1 million) for a total expense of $12.2 million. In third quarter 2011, stock-based compensation was allocated to operating expense ($463,000), exploration expense ($902,000) and general and administrative expense ($8.5 million) for a total expense of $10.2 million. In the first nine months 2012, stock-based compensation was allocated to operating expense ($1.6 million), exploration expense ($3.0 million) and general and administrative expense ($30.8 million) for a total expense of $36.8 million. In the first nine months 2011, stock-based compensation was allocated to operating expense ($1.4 million), exploration expense ($3.2 million) and general and administrative expense ($27.5 million) for a total expense of $33.2 million. Unlike the other forms of stock-based compensation mentioned above, the mark-to-market adjustment of the liability related to the vested restricted stock held in our deferred compensation plans is directly tied to the change in our stock price and not directly related to the functional expenses and therefore, is not allocated to the functional categories.

### Stock and Option Plans

We have two active equity-based stock plans, the 2005 Plan and the Director Plan. Under these plans, incentive and non-qualified stock options, SARs, restricted stock units and various other awards may be issued to directors and employees pursuant to decisions of the Compensation Committee, which is made up of non-employee, independent directors from the Board of Directors. All awards granted under these plans have been issued at prevailing market prices at the time of the grant. Of the 3.6 million grants outstanding at September 30, 2012, 32,450 of the grants relate to stock options with the remainder of 3.6 million grants relating to SARs. Information with respect to stock option and SARs activities is summarized below.

Table of Contents

| | Shares | Weighted Average Exercise Price |
|---|---|---|
| Outstanding at December 31, 2011 | 4,558,609 | $ 41.47 |
| Granted | 754,471 | 64.14 |
| Exercised | (1,697,091) | 28.61 |
| Expired/forfeited | (12,419) | 48.06 |
| Outstanding at September 30, 2012 | 3,603,570 | $ 52.25 |

**Stock Appreciation Right Awards**

During first nine months 2012, we granted SARs to officers and non-officer employees. The weighted average grant date fair value of these SARs, based on our Black-Scholes-Merton assumptions, is shown below:

| | Nine Months Ended September 30, 2012 |
|---|---|
| Weighted average exercise price per share | $ 64.14 |
| Expected annual dividends per share | 0.25% |
| Expected life in years | 3.7 |
| Expected volatility | 45% |
| Risk-free interest rate | 0.5% |
| Weighted average grant date fair value | $ 21.32 |

**Restricted Stock Awards**

*Equity Awards*

In the first nine months 2012, we granted 360,000 restricted stock Equity Awards to employees at an average grant price of $63.37 compared to 329,000 granted to employees at an average grant price of $49.47 in the same period of 2011. These awards generally vest over a three-year period. We recorded compensation expense for these awards of $8.2 million in the first nine months 2012 compared to $2.9 million in the same period of 2011. Equity Awards are not issued to employees until they are vested. Employees do not have the option to receive cash.

*Liability Awards*

In first nine months 2012, we granted 356,000 shares of restricted stock Liability Awards as compensation to employees at an average price of $63.88 with vesting generally over a three-year period and 14,700 were granted to directors at an average price of $64.35 with immediate vesting. In the same period of 2011, we granted 334,200 shares of Liability Awards as compensation to employees at an average price of $51.11 with vesting generally over a three-year period and 15,500 shares were granted to directors at an average price of $52.35 with immediate vesting. We recorded compensation expense for Liability Awards of $15.2 million in the first nine months 2012 compared to $14.6 million in the same period of 2011. Substantially all of these awards are held in our deferred compensation plan, are classified as a liability and are remeasured at fair value each reporting period. This mark-to-market adjustment is reported in the deferred compensation expense in our consolidated statements of operations (see additional discussion below).

Table of Contents

A summary of the status of our non-vested restricted stock outstanding at September 30, 2012 is summarized below:

| | Equity Awards | | Liability Awards | |
|---|---|---|---|---|
| | Shares | Weighted Average Grant Date Fair Value | Shares | Weighted Average Grant Date Fair Value |
| Outstanding at December 31, 2011 | 221,609 | $ 49.64 | 487,244 | $ 48.76 |
| Granted | 359,732 | 63.37 | 370,385 | 63.90 |
| Vested | (140,818) | 56.83 | (324,433) | 51.30 |
| Forfeited | (23,782) | 58.37 | (2,093) | 50.50 |
| Outstanding at September 30, 2012 | 416,741 | $ 58.56 | 531,103 | $ 57.76 |

**Deferred Compensation Plan**

Our deferred compensation plan gives directors, officers and key employees the ability to defer all or a portion of their salaries and bonuses and invest in Range common stock or make other investments at the individual s discretion. Range provides a partial matching contribution which vests over three years. The assets of the plans are held in a grantor trust, which we refer to as the Rabbi Trust, and are therefore available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. Our stock held in the Rabbi Trust is treated as a liability award as employees are allowed to take withdrawals from the Rabbi Trust either in cash or in Range stock. The liability for the vested portion of the stock held in the Rabbi Trust is reflected in the deferred compensation liability in the accompanying consolidated balance sheets and is adjusted to fair value each reporting period by a charge or credit to deferred compensation plan expense on our consolidated statements of operations. The assets of the Rabbi Trust, other than our common stock, are invested in marketable securities and reported at their market value in other assets in the accompanying consolidated balance sheets. The deferred compensation liability reflects the vested market value of the marketable securities and Range stock held in the Rabbi Trust. Changes in the market value of the marketable securities and changes in the fair value of the deferred compensation plan liability are charged or credited to deferred compensation plan expense each quarter. We recorded mark-to-market loss of $20.1 million in third quarter 2012 compared to mark-to-market loss of $8.7 million in third quarter 2011. We recorded mark-to-market loss of $21.6 million in the first nine months 2012 compared to mark-to-market loss of $33.6 million in the same period of 2011. The Rabbi Trust held 2.8 million shares (2.3 million of vested shares) of Range stock at September 30, 2012 compared to 2.8 million shares (2.3 million of vested shares) at December 31, 2011.

**(15) SUPPLEMENTAL CASH FLOW INFORMATION**

| | Nine Months Ended September 30, | |
|---|---|---|
| | 2012 | 2011 |
| | (in thousands) | |
| Net cash provided from operating activities included: | | |
| Income taxes paid to taxing authorities | $ 436 | $ 309 |
| Interest paid | 99,828 | 95,536 |
| Non-cash investing and financing activities included: | | |
| Asset retirement costs capitalized, net | 29,695 | 13,569 |

**(16) COMMITMENTS AND CONTINGENCIES**
**Litigation**

We are the subject of, or party to, a number of pending or threatened legal actions and claims arising in the ordinary course of our business. While many of these matters involve inherent uncertainty, we believe that the amount of the liability, if any, ultimately incurred with respect to proceedings or claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future annual results of operations. We will continue to evaluate our litigation on a quarter-by-quarter basis and will establish and adjust any litigation reserves as appropriate to reflect our assessment of the then current status of litigation.

Table of Contents

**Transportation and Gathering Contracts**

As of September 30, 2012, future minimum firm transportation and gathering contracts are as follows (in thousands):

| | Transportation and Gathering Contracts |
|---|---|
| 2012 (remaining) | $ 35,581 |
| 2013 | 145,981 |
| 2014 | 143,925 |
| 2015 | 153,468 |
| 2016 | 155,828 |
| Thereafter | 861,431 |
| | $ 1,496,214 |

**Drilling Contracts**

As of September 30, 2012, we have contracts with drilling contractors to use three drilling rigs with terms of up to four years with minimum future commitments of $5.9 million in fourth quarter 2012, $23.2 million in fiscal year 2013, $9.9 million in fiscal year 2014 and $2.2 million in fiscal year 2015. Early termination of these contracts at September 30, 2012 would require us to pay maximum penalties of $30.0 million. We do not expect to pay early termination penalties related to these contracts.

**(17) Capitalized Costs and Accumulated Depreciation, Depletion and Amortization [(a)]**

| | September 30, 2012 | December 31, 2011 |
|---|---|---|
| | (in thousands) | |
| Natural gas and oil properties: | | |
| Properties subject to depletion | $ 7,219,474 | $ 6,035,429 |
| Unproved properties | 781,371 | 748,598 |
| Total | 8,000,845 | 6,784,027 |
| Accumulated depreciation, depletion and amortization | (1,942,698) | (1,626,461) |
| Net capitalized costs | $ 6,058,147 | $ 5,157,566 |

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

**(18) Costs Incurred for Property Acquisition, Exploration and Development [(a)]**

| | Nine Months Ended September 30, 2012 | Year Ended December 31, 2011 |
|---|---|---|
| | (in thousands) | |

| | | |
|---|---|---|
| Acreage purchases | $ 173,718 | $ 220,576 |
| Development | 855,650 | 1,007,049 |
| Exploration: | | |
| Drilling | 268,328 | 226,920 |
| Expense | 48,738 | 77,259 |
| Stock-based compensation expense | 3,047 | 4,108 |
| Gas gathering facilities: | | |
| Development | 32,520 | 53,387 |
| Subtotal | 1,382,001 | 1,589,299 |
| Asset retirement obligations | 29,695 | 24,061 |
| Total Continuing operations | 1,411,696 | 1,613,360 |
| Discontinued operations | | 3,241 |
| Total costs incurred | $ 1,411,696 | $ 1,616,601 |

(a) Includes cost incurred whether capitalized or expensed.

Table of Contents

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

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. Certain sections of Management s Discussion and Analysis of Financial Condition and Results of Operations include forward-looking statements concerning trends or events potentially affecting our business. These statements contain words such as anticipates, believes, expects, targets, plans, projects, could, may, should, would or similar words indicating that future outcomes are uncertain. In accordance with provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, which could cause future outcomes to differ materially from those set forth in the forward-looking statements. These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. While management believes that these forward-looking statements are reasonable when made, there can be no assurance that future developments affecting us will be those that we anticipate. All comments concerning our expectations for future revenues and operating results are based on our forecasts for our existing operations and do not include the potential impact of any future acquisitions. For additional risk factors affecting our business, see Item 1A. Risk Factors as filed with our Annual Report on Form 10-K for the year ended December 31, 2011 as filed with the SEC on February 22, 2012.

**Overview of Our Business**

We are a Fort Worth, Texas-based independent natural gas, natural gas liquids ( NGLs ) and oil company primarily engaged in the exploration, development and acquisition of natural gas and oil properties in the Appalachian and Southwestern regions of the United States. We operate in one segment and have a single company-wide management team that administers all properties as a whole rather than by discrete operating segments. Unless otherwise indicated, the information included herein relates to our continuing operations.

Our objective is to build stockholder value through consistent growth in reserves and production on a cost-efficient basis. Our strategy to achieve our objective is to increase reserves and production through internally generated drilling projects occasionally coupled with complementary acquisitions. Our revenues, profitability and future growth depend substantially on prevailing prices for natural gas, NGLs and crude oil and on our ability to economically find, develop, acquire and produce natural gas, NGLs and oil reserves. We use the successful efforts method of accounting for our natural gas, NGLs and oil activities. Our corporate headquarters is located at 100 Throckmorton Street, Fort Worth, Texas.

**Recent Developments**

On October 9, 2012, we signed a definitive agreement to sell certain of our oil and gas properties in southern Oklahoma which includes approximately 45 producing wells for a purchase price of $135.0 million, subject to normal post-closing adjustments. The completion of the sale is dependent on prospective buyer due diligence procedures and there can be no assurance the sale will be completed or that there will not be changes to the sales price. The closing date is currently expected to be November 19, 2012.

**Market Conditions**

Prices for our products significantly impact our revenue, net income and cash flow. Natural gas, NGLs and oil are commodities and prices for commodities are inherently volatile. The following table lists average NYMEX prices for natural gas and oil for three months and nine months ended September 30, 2012 and 2011.

| | Three Months Ended September 30, 2012 | Three Months Ended September 30, 2011 | Nine Months Ended September 30, 2012 | Nine Months Ended September 30, 2011 |
|---|---|---|---|---|
| Average NYMEX prices [a] | | | | |
| Natural gas (per mcf) | $ 2.81 | $ 4.18 | $ 2.61 | $ 4.22 |
| Oil (per bbl) | $ 92.58 | $ 89.54 | $ 95.78 | $ 95.47 |

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

Table of Contents

**Consolidated Results of Operations**

***Overview of 2012 Results***

During third quarter 2012, we achieved the following financial and operating results:

- increased revenue from the sale of natural gas, NGL and oil by 11% from the same period of 2011;
- achieved 48% production growth;
- continued expansion of our activities in the Marcellus Shale by growing production, proving up acreage and acquiring additional unproved acreage;
- continued expansion of our activities in the horizontal Mississippian oil play by growing production and acquiring additional unproved acreage;
- reduced direct operating expenses per mcfe 33%;
- reduced our depletion, depreciation and amortization ( DD&A ) rate 11%;
- entered into additional derivative contracts for 2012, 2013 and 2014; and
- realized $178.2 million of cash flow from operating activities.

Total revenues decreased $75.7 million or 20% in third quarter 2012 over the same period of 2011. This decrease was due to a decrease in mark-to-market gain from derivatives and lower realized prices partially offset by higher production. Our third quarter 2012 production growth was due to the continued success of our drilling program, particularly in the Marcellus Shale. Third quarter 2012 natural gas production increased over 50% and, as we continue to focus our efforts on growth of our liquids production, third quarter production for oil and NGLs increased over 30%.

During the first nine months 2012, we achieved the following financial and operating results:

- increased revenue from the sale of natural gas, NGL and oil by 13% from the same period of 2011;
- achieved 50% production growth (excluding our Barnett Shale properties which were sold in April 2011);
- reduced direct operating expenses per mcfe 35%;
- reduced our DD&A rate 9%;

maintained a strong balance sheet by issuing $600.0 million of new 5.00% 10-year senior subordinated notes;

entered into additional derivative contracts for 2012, 2013 and 2014; and

realized $461.1 million of cash flow from operating activities.

Total revenues increased $65.6 million or 7% in the first nine months 2012 over the same period of 2011. This increase was due to higher production partially offset by lower realized prices and a decrease in the mark-to-market gain from derivatives. Our first nine months 2012 production growth is due to our continued successful drilling program, particularly in the Marcellus Shale.

We believe natural gas, NGLs and oil prices will remain volatile and will be affected by, among other things, weather, the U.S. and worldwide economy, new technology and the level of oil and gas production in North America and worldwide. Although we have entered into derivative contracts covering a portion of our production volumes for the remainder of 2012, 2013 and 2014, a sustained lower price environment would result in lower prices for unprotected volumes and reduce the prices that we can enter into derivative contracts for additional volumes in the future. As a result of the decline in natural gas prices, we continue to focus our capital budget expenditures on oil and liquids-rich-gas drilling activities.

***Natural Gas, NGLs and Oil Sales, Production and Realized Price Calculations***

Our revenues vary primarily as a result of changes in realized commodity prices, production volumes and the value of certain of our derivative contracts. We generally sell natural gas, NGLs and oil under two types of agreements, which are common in our industry. Revenue from the sale of natural gas, NGLs and oil sales include netback arrangements where we sell natural gas and oil at the wellhead and collect a price, net of transportation incurred by the purchaser. In this instance, we record revenue at the price we receive from the purchaser. Revenues are also realized from sales arrangements where we sell natural gas or oil at a specific delivery point and receive proceeds from the purchaser with no transportation deduction. Third party transportation costs we incur to get our commodity to the delivery point are reported in transportation, gathering and compression expense. Hedges included in natural gas, NGLs and oil sales reflect settlements on those derivatives that qualify for hedge accounting. Cash settlements and changes in the market value of derivative contracts that are not accounted for as hedges are included in derivative fair value income or loss in the statement of operations. For more information on revenues from derivative contracts that are not accounted for as hedges, see Derivative fair value (loss) income discussion below.

Table of Contents

In third quarter 2012, natural gas, NGLs and oil sales increased 11% from the same period of 2011 with a 48% increase in production partially offset by a 25% decrease in realized prices. In the first nine months 2012, natural gas, NGLs and oil sales increased 13% from the same period of 2011 with a 50% increase in production partially offset by a 25% decrease in realized prices. The following table illustrates the primary components of natural gas, NGLs and oil sales for the three months and the nine months ended September 30, 2012 and 2011 (in thousands):

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2012 | 2011 | Change | % | 2012 | 2011 | Change | % |
| **Natural gas, NGLs and oil sales** | | | | | | | | |
| Gas wellhead | $ 159,525 | $ 165,581 | $ (6,056) | (4%) | $ 399,006 | $ 446,564 | $ (47,558) | (11%) |
| Gas hedges realized [a] | 62,150 | 26,758 | 35,392 | 132% | 198,675 | 80,659 | 118,016 | 146% |
| Total gas revenue | $ 221,675 | $ 192,339 | $ 29,336 | 15% | $ 597,681 | $ 527,223 | $ 70,458 | 13% |
| Total NGLs revenue | $ 56,826 | $ 69,430 | $ (12,604) | (18%) | $ 189,604 | $ 188,851 | $ 753 | % |
| Oil wellhead | $ 59,221 | $ 42,461 | $ 16,760 | 39% | $ 166,718 | $ 125,472 | $ 41,246 | 33% |
| Oil hedges realized [a] | (682) | | (682) | % | (997) | | (997) | % |
| Total oil revenue | $ 58,539 | $ 42,461 | $ 16,078 | 38% | $ 165,721 | $ 125,472 | $ 40,249 | 32% |
| Combined wellhead | $ 275,572 | $ 277,472 | $ (1,900) | (1%) | $ 755,328 | $ 760,887 | $ (5,559) | (1%) |
| Combined hedges [a] | 61,468 | 26,758 | 34,710 | 130% | 197,678 | 80,659 | 117,019 | 145% |
| Total natural gas, NGLs and oil sales | $ 337,040 | $ 304,230 | $ 32,810 | 11% | $ 953,006 | $ 841,546 | $ 111,460 | 13% |

(a) Cash settlements related to derivatives that qualify for hedge accounting.

Our production continues to grow through drilling success as we place new wells on production offset by the natural decline of our natural gas and oil wells and asset sales. For third quarter 2012, our production volumes increased 62% in our Appalachian region and increased 1% in our Southwestern region when compared to the same period of 2011. For the nine months ended September 30, 2012, our production volumes increased 66% in our Appalachian region and increased 6% in our Southwestern region when compared to the same period of 2011. Our production for the three months and the nine months ended September 30, 2012 and 2011 is set forth in the following table:

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2012 | 2011 | Change | % | 2012 | 2011 | Change | % |
| **Production [a]** | | | | | | | | |
| Natural gas (mcf) | 57,347,638 | 37,441,857 | 19,905,781 | 53% | 156,274,072 | 100,058,851 | 56,215,221 | 56% |
| NGLs (bbls) | 1,843,667 | 1,430,568 | 413,099 | 29% | 4,975,086 | 3,798,635 | 1,176,451 | 31% |
| Crude oil (bbls) | 712,858 | 523,074 | 189,784 | 36% | 1,943,961 | 1,462,168 | 481,793 | 33% |
| Total (mcfe) [b] | 72,686,788 | 49,163,709 | 23,523,079 | 48% | 197,788,354 | 131,623,669 | 66,164,685 | 50% |
| **Average daily production [a]** | | | | | | | | |
| Natural gas (mcf) | 623,344 | 406,977 | 216,367 | 53% | 570,343 | 366,516 | 203,827 | 56% |
| NGLs (bbls) | 20,040 | 15,550 | 4,490 | 29% | 18,157 | 13,914 | 4,243 | 30% |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Crude oil (bbls) | 7,748 | 5,686 | 2,062 | 36% | 7,095 | 5,356 | 1,739 | 32% |
| Total (mcfe) [b] | 790,074 | 534,388 | 255,686 | 48% | 721,855 | 482,138 | 239,717 | 50% |

(a) Represents volumes sold regardless of when produced.

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

Our average realized price (including all derivative settlements and third-party transportation costs) received during third quarter 2012 was $4.17 per mcfe compared to $5.75 per mcfe in the same period of 2011. Our average realized price (including all derivative settlements and third-party transportation costs) received was $4.24 per mcfe in the nine months ended September 30, 2012 compared to $5.80 per mcfe in the same period of the prior year. Because we record transportation costs on two separate bases, as required by GAAP, we believe computed final realized prices should include the total impact of transportation, gathering and compression expense. Our average realized price (including all derivative settlements and third-party transportation costs) calculation also includes all cash settlements for derivatives, whether or not they qualify for hedge accounting. Average sales prices (wellhead) do not include derivative settlements or third party transportation costs which are

Table of Contents

reported in transportation, gathering and compression expense on the accompanying statements of operations. Average sales prices (wellhead) do include transportation costs where we receive net revenue proceeds. Average realized price calculations for the three months and the nine months ended September 30, 2012 and 2011 are shown below:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| **Average Prices** | | | | |
| Average sales prices (wellhead): | | | | |
| Natural gas (per mcf) | $ 2.78 | $ 4.42 | $ 2.55 | $ 4.46 |
| NGLs (per bbl) | 30.82 | 48.53 | 38.11 | 49.72 |
| Crude oil (per bbl) | 83.08 | 81.18 | 85.76 | 85.81 |
| Total (per mcfe) [a] | 3.79 | 5.64 | 3.82 | 5.78 |
| Average realized prices (including derivative settlements that qualify for hedge accounting): | | | | |
| Natural gas (per mcf) | $ 3.87 | $ 5.14 | $ 3.82 | $ 5.27 |
| NGLs (per bbl) | 30.82 | 48.53 | 38.11 | 49.72 |
| Crude oil (per bbl) | 82.12 | 81.18 | 85.25 | 85.81 |
| Total (per mcfe) [a] | 4.64 | 6.19 | 4.82 | 6.39 |
| Average realized prices (including all derivative settlements): | | | | |
| Natural gas (per mcf) | $ 3.88 | $ 5.33 | $ 3.85 | $ 5.40 |
| NGLs (per bbl) | 38.79 | 50.69 | 42.22 | 50.53 |
| Crude oil (per bbl) | 84.86 | 81.72 | 84.27 | 80.53 |
| Total (per mcfe) [a] | 4.88 | 6.41 | 4.93 | 6.46 |
| Average realized prices (including all derivative settlements and third party transportation costs paid by Range): | | | | |
| Natural gas (per mcf) | $ 3.03 | $ 4.52 | $ 3.02 | $ 4.58 |
| NGLs (per bbl) | 37.23 | 49.31 | 40.66 | 49.39 |
| Crude oil (per bbl) | 84.86 | 81.72 | 84.27 | 80.53 |
| Total (per mcfe) [a] | 4.17 | 5.75 | 4.24 | 5.80 |

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

**Derivative fair value (loss) income** was a loss of $40.7 million in third quarter 2012 compared to income of $65.8 million in the same period of 2011. Derivative fair value (loss) income was income of $47.0 million in the nine months ended September 30, 2012 compared to income of $78.0 million in the same period of 2011. Some of our derivatives do not qualify for hedge accounting and are accounted for using the mark-to-market accounting method whereby all realized and unrealized gains and losses related to these contracts are included in derivative fair value (loss) income in the accompanying consolidated statements of operations. Mark-to-market accounting treatment results in volatility of our revenues as unrealized gains and losses from derivatives are included in total revenue. As commodity prices increase or decrease, such changes will have an opposite effect on the mark-to-market value of our derivatives. Gains on our derivatives generally indicate lower wellhead revenues in the future while losses indicate higher future wellhead revenues. The decrease in the mark-to-market gain or loss in the third quarter and the nine months ended September 30, 2012 is primarily due to the change in the fair value of our oil and NGL derivatives. Hedge ineffectiveness, also included in derivative fair value (loss) income, is associated with contracts that qualify for hedge accounting. The ineffective portion is calculated as the difference between the changes in the fair value of the derivative and the estimated change in future cash flows from the item being hedged.

Table of Contents

The following table presents information about the components of derivative fair value (loss) income for the three months and the nine months ended September 30, 2012 and 2011 (in thousands):

| | Three Months Ended September 30, 2012 | Three Months Ended September 30, 2011 | Nine Months Ended September 30, 2012 | Nine Months Ended September 30, 2011 |
|---|---|---|---|---|
| Change in fair value of derivatives that do not qualify for hedge accounting [a] | $ (53,646) | $ 58,990 | $ 30,075 | $ 67,093 |
| Realized gain (loss) on settlements natural gas [b] [c] | | 5,334 | | 8,424 |
| Realized gain (loss) on settlements oil [b] [c] | 1,955 | 285 | (1,899) | (7,727) |
| Realized gain (loss) on settlements NGLs [b] [c] | 14,682 | 3,087 | 20,442 | 3,087 |
| Hedge ineffectiveness realized [c] | 988 | 2,036 | 3,451 | 4,558 |
| unrealized [a] | (4,707) | (3,971) | (5,061) | 2,531 |
| Derivative fair value (loss) income | $ (40,728) | $ 65,761 | $ 47,008 | $ 77,966 |

(a) These amounts are unrealized and are not included in average realized price calculations.
(b) These amounts represent realized gains and losses on settled derivatives that do not qualify for hedge accounting.
(c) These settlements are included in average realized price calculations (including all derivative settlements and third party transportation costs paid by Range).

**Gain (loss) on the sale of assets** was a gain of $949,000 in third quarter 2012 compared to a gain of $203,000 in the same period of 2011. In third quarter 2012, we recorded a pre-tax gain of $746,000 on the sale of unproved property in Pennsylvania where we received proceeds of $13.9 million. Gain (loss) on the sale of assets was a loss of $12.7 million in the first nine months 2012 compared to a loss of $1.3 million in the same period of 2011. In the first nine months 2012, we also sold a seventy-five percent interest in an East Texas prospect which included a suspended exploratory well and unproved properties for proceeds of $8.6 million resulting in a pre-tax loss of $10.9 million and recorded a $2.5 million pre-tax loss on the sale of a Marcellus exploratory well where we received proceeds of $2.5 million. In the first nine months 2011, we recorded a loss of $1.7 million related to the sale of certain derivatives included with the sale of our Barnett Shale properties.

**Other** revenue in third quarter 2012 was a loss of $2.4 million compared to a gain of $442,000 in the same period of 2011. The third quarter 2012 includes loss from equity method investments of $1.0 million and a transportation and gathering loss of $1.4 million. The third quarter 2011 includes loss from equity method investments of $641,000 offset by transportation and gathering revenue of $817,000. Other revenue for the nine months ended September 30, 2012 was a loss of $3.1 million compared to a gain of $357,000 in the same period of 2011. The nine months ended September 30, 2012 includes loss from equity method investments of $195,000 and a transportation and gathering loss of $3.3 million. The nine months ended September 30, 2011 includes various lawsuit proceeds and refunds partially offset by a loss from equity method investments of $1.4 million.

We believe some of our expense fluctuations are best analyzed on a unit-of-production, or per mcfe, basis. The following presents information about certain of our expenses on a per mcfe basis for the three months and the nine months ended September 30, 2012 and 2011. For the nine months ended September 30, 2012, production and ad valorem tax expense includes a Pennsylvania impact fee of $0.21 per mcfe of which $0.12 per mcfe is a retroactive adjustment for wells drilled prior to 2012.

| | Three Months Ended September 30, 2012 | Three Months Ended September 30, 2011 | Change | % Change | Nine Months Ended September 30, 2012 | Nine Months Ended September 30, 2011 | Change | % Change |
|---|---|---|---|---|---|---|---|---|
| Direct operating expense | $ 0.41 | $ 0.61 | $ (0.20) | (33%) | $ 0.43 | $ 0.66 | $ (0.23) | (35%) |
| Production and ad valorem tax expense | 0.12 | 0.15 | (0.03) | (20%) | 0.29 | 0.17 | 0.12 | 71% |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| General and administrative expense | 0.61 | 0.73 | (0.12) | (16%) | 0.64 | 0.83 | (0.19) | (23%) |
| Interest expense | 0.61 | 0.70 | (0.09) | (13%) | 0.63 | 0.69 | (0.06) | (9%) |
| Depletion, depreciation and amortization expense | 1.71 | 1.90 | (0.19) | (10%) | 1.69 | 1.85 | (0.16) | (9%) |

**Direct operating** expense was $29.6 million in third quarter 2012 compared to $29.8 million in the same period of 2011. We experience increases in operating expenses as we add new wells and manage existing properties. Direct operating expenses include normally recurring expenses to operate and produce our wells, non-recurring well workovers and repair-related expenses. Even though our production volumes increased 48%, on an absolute basis, our spending for direct operating expenses for third quarter 2012 decreased 1% with an increase in the number of producing wells more than offset by lower water hauling and disposal costs, equipment rental and well services. We incurred $1.4 million of workover costs in third quarter 2012 compared to $1.2 million of workover costs in the same period of 2011.

Table of Contents

On a per mcfe basis, direct operating expense in third quarter 2012 declined 33% to $0.41 from the same period of 2011, with the decrease consisting of lower water hauling and disposal costs, workover costs, equipment rental and well services. We expect to experience lower costs per mcfe as we increase production from our dry gas Marcellus Shale wells due to their lower operating cost relative to our other operating areas somewhat offset by higher operating costs on our liquids-rich wells. However, operating costs in the Mississippian play are higher on a per mcfe basis than the Marcellus Shale play. As production increases from the Mississippian play, our direct operating expense per mcfe will begin to increase.

Direct operating expense was $85.7 million in the first nine months 2012 compared to $87.1 million in the same period of 2011. Even though our production volumes increased 50%, on an absolute basis, our spending for direct operating expenses decreased 2% with an increase in the number of producing wells and higher workover costs offset by lower water hauling and disposal costs, equipment rental and well service costs. We incurred $3.5 million of workover costs in the first nine months 2012 compared to $2.2 million in the same period of 2011.

On a per mcfe basis, direct operating expense in the first nine months 2012 decreased 35% to $0.43 from the same period of 2011, with the decrease consisting of lower water hauling and disposal costs, lower equipment rental and well services. Stock-based compensation expense represents the amortization of restricted stock grants and SARs as part of the compensation of field employees. The following table summarizes direct operating expenses per mcfe for the three months and the nine months ended September 30, 2012 and 2011:

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2012 | 2011 | Change | % Change | 2012 | 2011 | Change | % Change |
| Lease operating expense | $ 0.38 | $ 0.57 | $ (0.19) | (33%) | $ 0.40 | $ 0.63 | $ (0.23) | (37%) |
| Workovers | 0.02 | 0.03 | (0.01) | (33%) | 0.02 | 0.02 | | % |
| Stock-based compensation (non-cash) | 0.01 | 0.01 | | % | 0.01 | 0.01 | | % |
| Total direct operating expense | $ 0.41 | $ 0.61 | $ (0.20) | (33%) | $ 0.43 | $ 0.66 | $ (0.23) | (35%) |

**Production and ad valorem taxes** are paid based on market prices, not hedged prices. This expense category also includes the new Pennsylvania impact fee. Production and ad valorem taxes (excluding the impact fee) were $3.4 million in third quarter 2012 compared to $7.3 million in the same period of 2011. On a per mcfe basis, production and ad valorem taxes (excluding the impact fee) decreased to $0.05 in third quarter 2012 compared to $0.15 in the same period of 2011 due to lower natural gas and oil prices and an increase in volumes not subject to production taxes. In February 2012, the Commonwealth of Pennsylvania enacted an impact fee on unconventional natural gas and oil production which includes the Marcellus Shale. Included in third quarter 2012 is a $5.4 million impact fee ($0.07 per mcfe) accrual.

Production and ad valorem taxes (excluding the impact fee) were $14.5 million ($0.07 per mcfe) in the first nine months 2012 compared to $21.7 million ($0.17 per mcfe) in the same period of 2011 due to lower natural gas and oil prices and an increase in volumes not subject to production taxes. The nine months ended September 30, 2012 also includes a $24.7 million ($0.12 per mcfe) retroactive impact fee which covers all wells drilled prior to 2012 which was paid in September 2012. Also included in first nine months 2012 is a $18.0 million impact fee ($0.09 per mcfe) for wells drilled prior to 2012 and wells drilled in the first nine months 2012 to be paid April 2013.

**General and administrative** expense was $44.5 million in third quarter 2012 compared to $35.9 million for the same period of 2011. The 2012 increase of $8.6 million when compared to 2011 is due to higher salaries and benefits ($2.4 million), an increase in stock-based compensation of $1.6 million and higher legal and office expenses, including information technology. We continue to incur higher wages which we consider necessary to remain competitive in the industry. Our number of general and administrative ( G&A ) employees increased 12% at September 30, 2012 when compared to September 30, 2011. General and administrative expense for the first nine months 2012 increased $18.2 million or 17% from the same period of the prior year primarily due to higher salaries and benefits ($10.0 million), an increase in stock-based compensation of $3.3 million, higher advertising costs ($1.5 million) and higher office expenses, including information technology, partially offset by a decrease in legal expenses which also includes an insurance recovery. Our personnel costs continue to increase as we invest in our technical teams and other staffing to support our expansion into our various shale plays. Stock-based compensation expense represents the amortization of restricted stock grants and stock appreciation rights granted to our G&A employees and directors as part of compensation. On a per mcfe basis, G&A expense decreased 16% from the third quarter 2011 and 23% from the nine months 2011 with an increase in spending more than offset by higher production volumes. The following table summarizes general and administrative expenses per mcfe for the three months and nine months ended September 30, 2012 and 2011:

28

Table of Contents

| | Three Months Ended September 30, 2012 | 2011 | Change | % Change | Nine Months Ended September 30, 2012 | 2011 | Change | % Change |
|---|---|---|---|---|---|---|---|---|
| General and administrative | $ 0.47 | $ 0.56 | $ (0.09) | (16%) | $ 0.48 | $ 0.62 | $ (0.14) | (23%) |
| Stock-based compensation (non-cash) | 0.14 | 0.17 | (0.03) | (18%) | 0.16 | 0.21 | (0.05) | (24%) |
| Total general and administrative expenses | $ 0.61 | $ 0.73 | $ (0.12) | (16%) | $ 0.64 | $ 0.83 | $ (0.19) | (23%) |

**Interest expense** was $44.0 million for third quarter 2012 and $124.1 million in the first nine months 2012 compared to $34.2 million for third quarter 2011 and $90.3 million in the first nine months 2011. The following table presents information about interest expense for the three months and the nine months ended September 30, 2012 and 2011 (in thousands):

| | Three Months Ended September 30, 2012 | 2011 | Nine Months Ended September 30, 2012 | 2011 |
|---|---|---|---|---|
| Bank credit facility | $ 3,224 | $ 1,443 | $ 7,884 | $ 6,854 |
| Subordinated notes | 38,344 | 30,843 | 109,365 | 92,877 |
| Amortization of deferred financing costs and other | 2,429 | 1,895 | 6,841 | 5,403 |
| Allocated to discontinued operations | | | | (14,791) |
| Total interest expense | $ 43,997 | $ 34,181 | $ 124,090 | $ 90,343 |

The increase in interest expense for third quarter 2012 from the same period of 2011 was primarily due to an increase in outstanding debt balances. In March 2012, we issued $600.0 million of 5.00% senior subordinated notes due 2022. We used the proceeds to repay $350.0 million of our outstanding credit facility balance and for general corporate purposes. In May 2011, we issued $500.0 million of 5.75% senior subordinated notes due 2021. We used the proceeds for general corporate purposes and to purchase or redeem $150.0 million of our 6.375% senior subordinated notes due 2015 and $250.0 million of our 7.5% senior subordinated notes due 2016. The 2012 and 2011 note issuances were undertaken to better match the maturities of our debt with the life of our properties and to give us greater liquidity for the near term. Average debt outstanding on the bank credit facility for third quarter 2012 was $375.2 million compared to no outstanding bank debt for the same period of 2011 and the weighted average interest rate on the bank credit facility was 2.1% in 2012.

The increase in interest expense for the first nine months 2012 from the same period of 2011 was due to an increase in outstanding debt balances and higher interest rates. Average debt outstanding on the bank credit facility was $239.9 million compared to $197.5 million for 2011 and the weighted average interest rate on the bank credit facility was 2.2% in the first nine months 2012 compared to 2.2% in the same period of 2011.

**Depletion, depreciation and amortization** ( DD&A ) was $123.1 million in third quarter 2012 compared to $93.6 million in the same period of 2011. The increase in third quarter 2012 when compared to the same period of 2011 is due to a 9% decrease in depletion rates more than offset by a 48% increase in production. Depletion expense, the largest component of DD&A, was $1.61 per mcfe in third quarter 2012 compared to $1.77 per mcfe in the same period of 2011. Depletion expense in the three months ended 2011 includes an adjustment of $4.2 million to record prior years depletion related to our Oklahoma properties.

DD&A was $332.0 million in the first nine months 2012 compared to $244.1 million in the same period of 2011. The increase for the nine months ended September 30, 2012 when compared to the nine months ended September 30, 2011 is due to an 8% decrease in depletion rates more than offset by a 50% increase in production. Depletion expense was $1.60 per mcfe in the first nine months 2012 compared to $1.73 per mcfe in the same period of 2011. We have historically adjusted our depletion rates in the fourth quarter of each year based on the year-end reserve report and other times during the year when circumstances indicate there has been a significant change in reserves or costs. The following table summarizes DD&A expense per mcfe for the three months and the nine months ended September 30, 2012 and 2011:

Table of Contents

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2012 | 2011 | Change | % Change | 2012 | 2011 | Change | % Change |
| Depletion and amortization | $ 1.61 | $ 1.77 | $ (0.16) | (9%) | $ 1.60 | $ 1.73 | $ (0.13) | (8%) |
| Depreciation | 0.04 | 0.10 | (0.06) | (60%) | 0.05 | 0.09 | (0.04) | (44%) |
| Accretion and other | 0.04 | 0.03 | 0.01 | 33% | 0.03 | 0.03 | | % |
| Total DD&A expense | $ 1.69 | $ 1.90 | $ (0.21) | (11%) | $ 1.68 | $ 1.85 | $ (0.17) | (9%) |

***Other Operating Expenses***

Our total operating expenses also include other expenses that generally do not trend with production. These expenses include stock-based compensation, transportation, gathering and compression, exploration expense, abandonment and impairment of unproved properties and deferred compensation plan expenses. In third quarter 2012, stock-based compensation was a component of direct operating expense ($598,000), exploration expense ($1.1 million) and general and administrative expense ($10.1 million) for a total of $12.2 million. In third quarter 2011, stock-based compensation was a component of direct operating expense ($463,000), exploration expense ($902,000) and general and administrative expense ($8.5 million) for a total of $10.2 million. In the first nine months 2012, stock-based compensation was allocated to direct operating expense ($1.6 million), exploration expense ($3.0 million) and general and administrative expense ($30.8 million) for a total of $36.8 million. In the first nine months 2011, stock-based compensation was allocated to direct operating expense ($1.4 million), exploration expense ($3.2 million) and general and administrative expense ($27.5 million) for a total of $33.2 million. Stock-based compensation includes the amortization of restricted stock grants and SARs grants.

**Transportation, gathering and compression** expense was $51.6 million in third quarter 2012 compared to $32.4 million in the same period of 2011. Transportation, gathering and compression expenses was $137.2 million in the first nine months 2012 compared to $86.2 million in the same period of 2011. These third party costs are higher than 2011 due to our production growth in the Marcellus Shale where we have third party gathering and compression agreements. We have included these costs in the calculation of average realized prices (including all derivative settlements and third party transportation expenses paid by Range).

**Exploration** expense was $14.8 million in third quarter 2012 compared to $17.6 million in the same period of 2011. Exploration expense was lower in third quarter 2012 when compared to 2011 due to lower seismic costs and lower dry hole costs. The nine months ended September 30, 2012 also includes lower dry hole costs compared to the same period of 2011, and lower delay rentals. The following table details our exploration related expenses for the three months and the nine months ended September 30, 2012 and 2011 (in thousands):

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2012 | 2011 | Change | % Change | 2012 | 2011 | Change | % Change |
| Seismic | $ 6,995 | $ 8,619 | $ (1,624) | (19%) | $ 26,763 | $ 26,156 | $ 607 | 2% |
| Delay rentals and other | 3,495 | 2,572 | 923 | 36% | 11,084 | 14,365 | (3,281) | (23%) |
| Personnel expense | 3,121 | 3,058 | 63 | 2% | 10,059 | 10,234 | (175) | (2%) |
| Stock-based compensation expense | 1,126 | 849 | 277 | 33% | 3,047 | 3,115 | (68) | (2%) |
| Dry hole expense | 15 | 2,508 | (2,493) | (99%) | 832 | 2,515 | (1,683) | (67%) |
| Total exploration expense | $ 14,752 | $ 17,606 | $ (2,854) | (16%) | $ 51,785 | $ 56,385 | $ (4,600) | (8%) |

**Abandonment and impairment of unproved properties** was $40.1 million in third quarter 2012 compared to $16.6 million in the same period of 2011. Abandonment and impairment of unproved properties was $104.0 million in the first nine months 2012 compared to $52.1 million in the same period of 2011. We assess individually significant unproved properties for impairment on a quarterly basis and recognize a loss where circumstances indicate impairment in value. In determining whether a significant unproved property is impaired we consider numerous factors including, but not limited to, current exploration plans, favorable or unfavorable activity on the property being evaluated and/or adjacent properties, our geologists evaluation of the property and the remaining months in the lease term for the property. Impairment of individually insignificant unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. As we continue to review our acreage positions and high grade our drilling inventory based on the current price environment, additional leasehold impairments and abandonments will likely be recorded. The increase from 2011 to 2012 is primarily related to our Marcellus Shale operations and is due, in part, to lower natural gas prices and plans to move towards areas with higher expectation of wet gas. In third quarter 2012, we impaired individually significant unproved properties in the Barnett shale of North Texas (the last of our unproved properties in the area) for $19.6 million because we have determined we will not drill and will allow the leases to expire. Also, due to a transaction in second quarter 2012, we impaired individually significant unproved properties in Pennsylvania for $23.1 million because we will not drill in these areas.

**Deferred compensation plan** expense was $20.1 million in third quarter 2012 compared to $8.7 million in the same period of 2011. This non-cash item relates to the increase or decrease in value of the liability associated with our common stock that is vested and held in our deferred compensation plan. The deferred compensation liability is adjusted to fair value by a charge or a credit to deferred compensation plan expense. Our stock price increased from $61.87 at June 30, 2012 to $69.87 at September 30, 2012. In the same quarter of the prior year, our stock price increased from $55.50 at June 30, 2011 to $58.46 at September 30, 2011. Deferred compensation plan expense was $21.6 million for the nine months ended 2012 compared to $33.6 million in the same period of 2011. During the first nine months 2012, our stock price increased from $61.94 at December 31, 2011 to $69.87 at September 30, 2012. In the first nine months 2011, our stock price increased from $44.98 at December 31, 2010 to $58.46 at September 30, 2011.

**Loss on extinguishment of debt** for the nine months ended September 30, 2011 was $18.6 million. In May and June 2011, we purchased or redeemed our 6.375% senior subordinated notes due 2015 at a price equal to 102.31% and we purchased or redeemed our 7.5% senior subordinated notes due 2016 at a price equal to 103.95%. We recorded a loss on extinguishment of debt of $18.6 million which includes a call premium and other consideration of $13.3 million and expensing of related deferred financing costs on the repurchased debt. The purchase and redemption of our 6.375% senior subordinated notes and our 7.5% senior subordinated notes was funded by the proceeds received from the issuance, in May 2011, of our $500.0 million 5.75% senior subordinated notes due in 2021.

**Impairment of proved properties and other assets** was $1.3 million in the third quarter and nine months ended September 30, 2012. The third quarter 2012 includes $1.3 million impairment on surface acreage in Texas. Impairment expense in the three months and the nine months ended September 30, 2011 includes $31.2 million related to our East Texas proved oil and gas properties and $7.5 million related to our Gulf Coast onshore proved properties.

**Income tax (benefit) expense** was a benefit of $29.1 million in third quarter 2012 compared to income tax expense of $22.5 million in third quarter 2011. The decrease in income taxes in third quarter 2012 reflects a 249% decrease in income from continuing operations when compared to the same period of 2011. For the third quarter, the effective tax rate was 35.1% in 2012 compared to 40.4% in 2011. Income tax benefit was $17.9 million in the first nine months 2012 compared to income tax expense of $35.3 million in the same period of 2011. The decrease in income taxes in the nine months ended September 30, 2012 reflects a 172% decrease in income from continuing operations when compared to the same period of 2011. For the nine months ended September 30, 2012, the effective tax rate was 30.9% compared to 43.7% in the nine months ended September 30, 2011. The 2012 and 2011 effective tax rates were different than the statutory tax rate due to state income taxes, permanent differences and changes in our valuation allowances related to our deferred tax asset for future deferred compensation plan distributions to senior executives to the extent their estimated future compensation (including these distributions) would exceed the $1.0 million deductible limit provided under section 162 (m) of the Internal Revenue Code. We expect our effective tax rate to be approximately 40% for the remainder of 2012.

**Discontinued operations** include the operating results and impairment losses related to our Barnett Shale properties. Substantially all of these properties were sold in April 2011 for proceeds of $889.3 million including certain derivatives assumed by the buyer and we recorded a gain of $4.9 million on the sale. See also Note 4 to the accompanying financial statements. Interest expense is allocated to discontinued operations based on the ratio of net assets of discontinued operations to our consolidated net assets plus long-term debt.

**Management s Discussion and Analysis of Financial Condition, Capital Resources and Liquidity**

Our main sources of liquidity and capital resources are internally generated cash flow from operations, a bank credit facility with uncommitted and committed availability, access to the debt and equity capital markets and asset sales. We continue to take steps to ensure adequate capital resources and liquidity to fund our capital expenditure program. In the first nine months 2012, we entered into additional commodity derivative contracts for 2012, 2013 and 2014 to protect future cash flows. In March 2012, we issued $600.0 million of new 5.00% ten-year senior subordinated notes. On April 9, 2012, we increased our committed facility amount under our bank credit facility from $1.5 billion to $1.75 billion and on October 4, 2012, our borrowing base and facility amount were reaffirmed.

During first nine months 2012, our net cash provided from continuing operations of $461.1 million, proceeds from the sale of assets of $32.1 million, proceeds from the issuance of our 5.00% senior subordinated notes and borrowings under our bank credit facility were used to fund $1.3 billion of capital expenditures (including acreage acquisitions). At September 30, 2012, we had $151,000 in cash and total assets of $6.7 billion.

Long-term debt at September 30, 2012 totaled $2.8 billion, including $461.0 million outstanding on our bank credit facility and $2.4 billion of senior subordinated notes. Our available committed borrowing capacity at September 30, 2012 was $1.2 billion. Cash is required to fund capital expenditures necessary to offset inherent declines in production and reserves that are typical in the oil and natural 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 currently believe that net cash generated from operating activities, unused committed borrowing capacity under the bank credit facility and proceeds from asset sales combined with our natural gas, NGLs and oil derivatives currently in place will be adequate to satisfy near-term

Table of Contents

financial obligations and liquidity needs. To the extent our capital requirements exceed our internally generated cash flow and proceeds from asset sales, debt or equity may be issued to fund these requirements. 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 natural gas business. A material drop in natural gas, NGLs and oil prices or a reduction in production and reserves would reduce our ability to fund capital expenditures, meet financial obligations and remain profitable. We operate in an environment with numerous financial and operating risks, including, but not limited to, the inherent risks of the search for, development and production of natural gas, NGLs and oil, the ability to buy properties and sell production at prices which provide an attractive return and the highly competitive nature of the industry. Our ability to expand our reserve base is, in part, dependent on obtaining sufficient capital through internal cash flow, bank borrowings, asset sales or the issuance of debt or equity securities. There can be no assurance that internal cash flow and other capital sources will provide sufficient funds to maintain capital expenditures that we believe are necessary to offset inherent declines in production and proven reserves.

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

**Credit Arrangements**

As of September 30, 2012, we maintained a $2.0 billion revolving credit facility, which we refer to as our bank credit facility. The bank credit facility is secured by substantially all of our assets and has a maturity date of February 18, 2016. Availability under the bank credit facility is subject to a borrowing base set by the lenders semi-annually with an option to set more often in certain circumstances. The borrowing base is dependent on a number of factors but primarily on the lenders assessment of future cash flows. Redeterminations of the borrowing base require approval of two thirds of the lenders; increases to the borrowing base require 97% lender approval. On April 9, 2012, the facility amount on our bank credit facility was increased from $1.5 billion to $1.75 billion and we added three additional banks and, on October 4, 2012, our borrowing base was reaffirmed at $2.0 billion and our facility amount was also reaffirmed at $1.75 billion. Our current bank group is currently comprised of twenty-eight financial institutions.

Our bank debt and our subordinated notes impose limitations on the payment of dividends and other restricted payments (as defined under the debt agreements for our bank debt and our subordinated notes). The debt agreements also contain customary covenants relating to debt incurrence, working capital, dividends and financial ratios. We were in compliance with all covenants at September 30, 2012.

**Capital Requirements**

Our primary capital requirements are for exploration, development and acquisition of natural gas and oil properties, repayment of principal and interest on outstanding debt and payment of dividends. During the first nine months 2012, $1.2 billion of capital was expended on drilling projects. Also in the first nine months 2012, $173.7 million was expended on acquisitions of unproved acreage, primarily in the Marcellus Shale and in the horizontal Mississippian oil play. Our 2012 capital program, excluding acquisitions, is expected to be funded by net cash flow from operations, a debt offering, proceeds from asset sales and borrowings under our credit facility. Our capital expenditure budget for 2012 is currently set at $1.6 billion, excluding proved property acquisitions. To the extent capital requirements exceed internally generated cash flow, proceeds from asset sales and our committed capacity under our bank credit facility, then debt or equity may be issued in capital market transactions to fund these requirements. On October 9, 2012, we signed a definitive agreement to sell certain of our oil and gas properties in southern Oklahoma for a purchase price of $135.0 million. We monitor our capital expenditures on an ongoing basis, adjusting the amount up or down and also between our operating regions, depending on commodity prices, cash flow and projected returns. Also, our obligations may change due to acquisitions, divestitures and continued growth. We may issue additional shares of stock, subordinated notes or other debt securities to fund capital expenditures, acquisitions, extend maturities or to repay debt.

The forward-looking statements about our capital budget are based on current expectations, estimates and projections and are not guarantees of future performance. Actual results may differ materially from these expectations, estimates and projections and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Some factors that could cause actual results to differ materially include prices of and demand for natural gas and oil, actions of competitors, disruptions or interruptions of our production and unforeseen hazards such as weather conditions, acts of war or terrorists acts and the government or military response, and other operating and economic considerations.

**Table of Contents**

**Cash Flow**

Cash flows from operations are primarily affected by production volumes and commodity prices, net of the effects of settlements of our derivatives. Our cash flows from operations are also impacted by changes in working capital. We generally maintain low cash and cash equivalent balances because we use available funds to reduce our bank debt. Short-term liquidity needs are satisfied by borrowings under our bank credit facility. Because of this, and since our principal source of operating cash flows (proved reserves to be produced in the following year) cannot be reported as working capital, we often have low or negative working capital. We sell a large portion of our production at the wellhead under floating market contracts. From time to time, we enter into various derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future natural gas, NGLs and oil production. The production we hedge has varied and will continue to vary from year to year depending on, among other things, our expectation of future commodity prices. Any payments due to counterparties under our derivative contracts should ultimately be funded by prices received from the sale of our production. Production receipts, however, often lag payments to the counterparties. Any interim cash needs are funded by borrowings under the bank credit facility. As of September 30, 2012, we have entered into hedging agreements covering 62.5 Bcfe for 2012, 195.3 Bcfe for 2013 and 131.8 Bcfe for 2014.

**Net cash provided from continuing operations** in first nine months 2012 was $461.1 million compared to $428.9 million in the same period of 2011. Cash provided from continuing operations is largely dependent upon commodity prices and production, net of the effects of settlement of our derivative contracts. The increase in cash provided from operating activities from 2011 to 2012 reflects a 50% increase in production partially offset by lower realized prices (a decline of 27%) and higher operating costs. As of September 30, 2012, we have hedged approximately 81% of our projected production for the remainder of 2012, with approximately 84% of our projected natural gas production hedged. Net cash provided from continuing operations is also affected by working capital changes or the timing of cash receipts and disbursements. Changes in working capital (as reflected in our consolidated statements of cash flows) for first nine months 2012 was a positive $26.3 million compared to negative $30.8 million for the same period of 2011.

**Net cash provided from discontinued operations** for the first nine months 2011 was $19.5 million. Substantially all of our Barnett Shale properties were sold in April 2011 with a February 1, 2011 effective date.

**Net cash used in investing activities from continuing operations** in first nine months 2012 was $1.3 billion compared to $983.7 million in the same period of 2011.

During the first nine months 2012, we:

- spent $1.2 billion on natural gas and oil property additions;
- spent $175.0 million on acreage primarily in the Marcellus Shale; and
- received proceeds from asset sales of $32.1 million.

During the first nine months 2011, we:

- spent $859.8 million on natural gas and oil property additions;
- spent $151.1 million on acreage primarily in the Marcellus Shale; and
- received proceeds from asset sales of $40.3 million.

**Net cash provided from financing activities** in the first nine months ended 2012 was an increase of $848.6 million compared to a decrease of $256.3 million in the same period of 2011. Historically, sources of financing have been primarily bank borrowings and capital raised through equity and debt offerings.

During the first nine months 2012, we:

- borrowed $1.1 billion and repaid $865.0 million under our bank credit facility; ending the quarter with a $461.0 million outstanding balance on our bank debt;
- issued $600.0 million aggregate principal amounts of 5.00% senior subordinated notes due 2022 with net proceeds of approximately $589.5 million; and
- spent $12.6 million related to debt issuance costs.

During the first nine months 2011, we:

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

**Cash Dividend Payments**

The amount of future dividends is subject to declaration by the Board of Directors and primarily depends on earnings, capital expenditures and various other factors. On September 4, 2012, the Board of Directors declared a dividend of four cents per share ($6.5 million) on our common stock, which was paid on September 28, 2012 to stockholders of record at the close of business on September 17, 2012.

**Cash Contractual Obligations**

Our contractual obligations include long-term debt, operating leases, drilling commitments, derivative obligations, asset retirement obligations and transportation commitments. As of September 30, 2012, we do not have any capital leases. As of September 30, 2012, we do not have any significant off-balance sheet debt or other such unrecorded obligations and we have not guaranteed any debt of any unrelated party. As of September 30, 2012, we had a total of $62.1 million of undrawn letters of credit under our bank credit facility supporting obligations in the table below.

The following table summarizes our contractual financial obligations at September 30, 2012 and their future maturities. In addition to the table below, we have contracted with several pipeline companies through 2029 to deliver natural gas and NGL production volumes from Marcellus Shale wells, which is contingent on physical pipeline construction and modifications and therefore, is not included below. We expect to fund these contractual obligations with cash generated from operating activities, borrowings under our bank credit facility, additional debt issuances and proceeds from asset sales (in thousands).

| | Payment due by period | | | | | |
|---|---|---|---|---|---|---|
| | Remaining 2012 | 2013 | 2014 | 2015 and 2016 | Thereafter | Total |
| Bank debt due 2016 | $ | $ | $ | $ 461,000[(a)] | $ | $ 461,000 |
| 7.50% senior subordinated notes due 2017 | | | | | 250,000 | 250,000 |
| 7.25% senior subordinated notes due 2018 | | | | | 250,000 | 250,000 |
| 8.00% senior subordinated notes due 2019 | | | | | 300,000 | 300,000 |
| 6.75% senior subordinated notes due 2020 | | | | | 500,000 | 500,000 |
| 5.75% senior subordinated notes due 2021 | | | | | 500,000 | 500,000 |
| 5.00% senior subordinated notes due 2022 | | | | | 600,000 | 600,000 |
| Operating leases | 2,958 | 11,827 | 11,707 | 20,637 | 28,432 | 75,561 |
| Drilling rig commitments | 5,926 | 23,173 | 9,880 | 2,215 | | 41,194 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Transportation commitments | 35,581 | 145,981 | 143,925 | 309,296 | 861,431 | 1,496,214 |
| Hydraulic fracturing services | 2,000 | 12,000 | | | | 14,000 |
| Other purchase obligations | 801 | 2,742 | 266 | 345 | 1,626 | 5,780 |
| Derivative obligations [b] | (313) | 5,847 | 7,699 | | | 13,233 |
| Asset retirement obligation liability [c] | 5,005 | 9,610 | 385 | 4,441 | 97,149 | 116,590 |
| Total contractual obligations [d] | $ 51,958 | $ 211,180 | $ 173,862 | $ 797,934 | $ 3,388,638 | $ 4,623,572 |

(a) Due at termination date of our bank credit facility. Interest paid on our bank credit facility would be approximately $8.2 million each year assuming no change in the interest rate or outstanding balance.

(b) Derivative obligations represent net open derivative contracts valued as of September 30, 2012. While such payments will be funded by proceeds received from the sale of our production, production receipts may be received after our payments to counterparties, which can result in borrowings under our bank credit facility.

(c) The ultimate settlement amount and timing cannot be precisely determined in advance. See Note 10 to our consolidated financial statements.

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

Table of Contents

**Hedging Oil and Gas Prices**

We use commodity-based derivative contracts to manage our exposure to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. We do not utilize complex derivatives, as we typically utilize commodity swap, collar and call option contracts to (1) reduce the effect of price volatility on the commodities we produce and sell and (2) support our annual capital budget and expenditure plans. In 2011, we also entered into sold NGL derivative swap contracts for the natural gasoline component of natural gas liquids and in 2012 we entered into purchased derivative swaps for natural gasoline. In addition, in second quarter 2012, we entered into NGL derivative swap contracts for propane. While there is a risk that the financial benefit of rising natural gas, NGLs and oil prices may not be captured, we believe the benefits of stable and predictable cash flow are more important. Among these benefits are a more efficient utilization of existing personnel and planning for future staff additions, the flexibility to enter into long-term projects requiring substantial committed capital, smoother and more efficient execution of our ongoing development drilling and production enhancement programs, more consistent returns on invested capital, and better access to bank and other credit markets.

At September 30, 2012, we had open swap contracts covering 89.6 Bcf of natural gas at prices averaging $3.62 per mcf, 3.3 million barrels of oil at prices averaging $95.70 per barrel, 3.0 million net barrels of NGLs (the C5 component of NGLs) at prices averaging $95.80 per barrel and 2.4 million barrels of NGLs (the C3 component of NGLs) at prices averaging $36.27 per barrel. We had collars covering 232.0 Bcf of natural gas at weighted average floor and cap prices of $4.23 to $4.83 per mcf and 2.0 million barrels of oil at weighted average floor and cap prices of $86.88 to $98.17 per barrel. We also have sold call options covering 0.4 million barrels of oil at a weighted average price of $85.00 per barrel and purchased put options for 0.2 million barrels of oil at a weighted average price of $80.00 per barrel. The fair value of these contracts, 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, approximated a pretax gain of $139.3 million at September 30, 2012. The contracts expire monthly through December 2014.

At September 30, 2012, the following commodity derivative contracts were outstanding:

| Period | Contract Type | Volume Hedged | Weighted Average Hedge Price |
|---|---|---|---|
| Natural Gas | | | |
| 2012 | Collars | 279,641 Mmbtu/day | $ 4.76 $ 5.22 |
| 2013 | Collars | 240,000 Mmbtu/day | $ 4.73 $ 5.20 |
| 2014 | Collars | 325,000 Mmbtu/day | $ 3.75 $ 4.47 |
| 2012 | Swaps | 270,000 Mmbtu/day | $ 3.77 |
| 2013 | Swaps | 177,521 Mmbtu/day | $ 3.57 |
| Crude Oil | | | |
| 2012 | Collars | 2,000 bbls/day | $ 70.00 $ 80.00 |
| 2013 | Collars | 3,000 bbls/day | $ 90.60 $ 100.00 |
| 2014 | Collars | 2,000 bbls/day | $ 85.55 $ 100.00 |
| 2012 | Call Options | 4,700 bbls/day | $ 85.00 |
| 2012 | Put Options | 2,500 bbls/day | $ 80.00 |
| 2013 | Swaps | 5,081 bbls/day | $ 96.59 |
| 2014 | Swaps | 4,000 bbls/day | $ 94.56 |
| NGLs (Natural Gasoline) | | | |
| 2012 | Sold Swaps | 12,000 bbls/day | $ 96.28 |
| 2013 | Sold Swaps | 8,000 bbls/day | $ 89.64 |
| 2012 | Purchased Swaps | 5,500 bbls/day | $ 82.37 |
| 2013 | Purchased Swaps | 1,500 bbls/day | $ 76.30 |
| NGLs (Propane) | | | |
| 2012 | Swaps | 6,000 bbls/day | $ 38.67 |
| 2013 | Swaps | 5,000 bbls/day | $ 35.55 |

The United States Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as Range, that participate in that market. The new regulation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act required the Commodities Futures Trading Commission (the CFTC ) and the SEC to promulgate rules and regulations implementing the new legislation. In July 2012 certain definitions were adopted by the SEC and the CFTC and based on those definitions, we believe we will qualify for the end-user exception related to the clearing requirement for swaps but we will be required to adhere to new reporting requirements.

Table of Contents

**Interest Rates**

At September 30, 2012, we had $2.8 billion of debt outstanding. Of this amount, $2.4 billion bears interest at fixed rates averaging 6.4%. Bank debt totaling $461.0 million bears interest at floating rates, which averaged 1.8% at September 30, 2012. The 30-day LIBOR rate on September 30, 2012 was 0.2%. A 1% increase in short-term interest rates on the floating-rate debt outstanding on September 30, 2012 would cost us approximately $4.6 million in additional annual interest expense.

**Off-Balance Sheet Arrangements**

We do not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance our liquidity or capital resource position, or for any other purpose. However, as is customary in the oil and gas industry, we have various contractual work commitments some of which are described above under cash contractual obligations.

**Inflation and Changes in Prices**

Our revenues, the value of our assets and our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in natural gas, NGLs and oil prices and the costs to produce our reserves. Natural gas, NGLs and oil prices are subject to significant fluctuations that are beyond our ability to control or predict. Although certain of our costs and expenses are affected by general inflation, inflation does not normally have a significant effect on our business. We expect costs for the remainder of 2012 to continue to be a function of supply and demand.

Table of Contents

**ITEM 3. QUANTITIVE 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 natural gas, NGLs and oil prices and interest rates. The disclosures are not meant to be precise 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 exposure. All of our market-risk sensitive instruments were entered into for purposes other than trading. All accounts are US dollar denominated.

**Market Risk**

We are exposed to market risks related to the volatility of natural gas, NGLs and oil prices. We employ various strategies, including the use of commodity derivative instruments, to manage the risks related to these price fluctuations. These derivatives instruments apply to a varying portion of our production and provide only partial price protection. These arrangements limit the benefit to us of increases in prices but offer protection in the event of price declines. Further, if our counterparties defaulted, this protection might be limited as we might not receive the benefits of the derivatives. Realized prices are primarily driven by worldwide prices for oil and spot market prices for North American gas production. Natural gas and oil prices have been volatile and unpredictable for many years. Natural gas prices affect us more than oil prices because approximately 79% of our December 31, 2011 proved reserves are natural gas. We are also exposed to market risks related to changes in interest rates. These risks did not change materially from December 31, 2011 to September 30, 2012.

**Commodity Price Risk**

We use commodity-based derivative contracts to manage exposures to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. We do not utilize complex derivatives such as swaptions, knockouts or extendable swaps. At times, 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. We have also entered into call option derivative contracts under which we sold call options in exchange for a premium from the counterparty. At the time of settlement of these monthly call options, if the market price exceeds the fixed price of the call option, we will pay the counterparty such excess and if the market settles below the fixed price of the call option, no payment is due from either party. At September 30, 2012, our derivatives program includes swaps (both purchased and sold NGL swaps), collars, call and put options. As of September 30, 2012, we had open swap contracts covering 89.6 Bcf of natural gas at prices averaging $3.62 per mcf, 3.3 million barrels of oil at prices averaging $95.70 per barrel, 3.0 million net barrels of NGLs (the C5 component of NGLs) at prices averaging $95.80 per barrel and 2.4 million barrels of NGLs (the C3 component of NGLs) at prices averaging $36.27 per barrel. We had collars covering 232.0 Bcf of natural gas at weighted average floor and cap prices of $4.23 to $4.83 per mcf and 2.0 million barrels of oil at weighted average floor and cap prices of $86.88 to $98.17 per barrel. We also have sold call options covering 0.4 million barrels of oil at a weighted average price of $85.00 per barrel and purchased put options for 0.2 million barrels of oil at a weighted average price of $80.00 per barrel. These contracts expire monthly through December 2014. The fair value of these contracts, represented by the estimated amount that would be realized upon immediate liquidation as of September 30, 2012, approximated a net unrealized pre-tax gain of $139.3 million.

**Table of Contents**

At September 30, 2012, the following commodity derivative contracts were outstanding:

| Period | Contract Type | Volume Hedged | Weighted Average Hedge Price | | Fair Market Value (in thousands) | |
|---|---|---|---|---|---|---|
| Natural Gas | | | | | | |
| 2012 | Collars | 279,641 Mmbtu/day | $ 4.76 | $ 5.22 | $ | 38,267 |
| 2013 | Collars | 240,000 Mmbtu/day | $ 4.73 | $ 5.20 | $ | 82,549 |
| 2014 | Collars | 325,000 Mmbtu/day | $ 3.75 | $ 4.47 | $ | (9,887) |
| 2012 | Swaps | 270,000 Mmbtu/day | $ 3.77 | | $ | 11,975 |
| 2013 | Swaps | 177,521 Mmbtu/day | $ 3.57 | | $ | (17,662) |
| Crude Oil | | | | | | |
| 2012 | Collars | 2,000 bbls/day | $ 70.00 | $ 80.00 | $ | (2,396) |
| 2013 | Collars | 3,000 bbls/day | $ 90.60 | $ 100.00 | $ | 975 |
| 2014 | Collars | 2,000 bbls/day | $ 85.55 | $ 100.00 | $ | 121 |
| 2012 | Call options | 4,700 bbls/day | $ 85.00 | | $ | (3,733) |
| 2012 | Put options | 2,500 bbls/day | $ 80.00 | | $ | 77 |
| 2013 | Swaps | 5,081 bbls/day | $ 96.59 | | $ | 5,401 |
| 2014 | Swaps | 4,000 bbls/day | $ 94.56 | | $ | 4,447 |
| NGLs (Natural Gasoline) | | | | | | |
| 2012 | Sold Swaps | 12,000 bbls/day | $ 96.28 | | $ | 13,264 |
| 2013 | Sold Swaps | 8,000 bbls/day | $ 89.64 | | $ | 18,195 |
| 2012 | Purchased Swaps | 5,500 bbls/day | $ 82.37 | | $ | 952 |
| 2013 | Purchased Swaps | 1,500 bbls/day | $ 76.30 | | $ | 3,831 |
| NGLs (Propane) | | | | | | |
| 2012 | Swaps | 6,000 bbls/day | $ 38.67 | | $ | (87) |
| 2013 | Swaps | 5,000 bbls/day | $ 35.55 | | $ | (7,033) |

We expect our NGL production to continue to increase. In our Marcellus Shale operations, propane is a large product component of our NGL production and we also believe NGL prices are somewhat seasonal. Therefore, the percentage of NGL prices to NYMEX WTI (or West Texas Intermediate) will vary due to product components, seasonality and geographic supply and demand. We sell NGLs in several regional markets.

As of September 30, 2012, the relationship between the price of oil and the price of natural gas is at an unprecedented spread. Normally, natural gas liquids production is a by-product of natural gas production. Due to the current differences in prices, we and other producers may choose to sell natural gas at or below cost or otherwise dispose of natural gas to allow for the sale of only natural gas liquids.

Currently, because there is little demand, or facilities to supply the existing demand, for ethane in the Appalachian region, for our Appalachian production volumes, ethane remains in the natural gas stream. We currently have waivers from two transmission pipelines that allow us to leave ethane in the residue natural gas. We believe the limits are sufficient to cover our production through 2014. We have announced three ethane agreements where we have contracted to either sell or transport ethane from our Marcellus Shale area, which are expected to begin operations in late 2013, early 2014 and early 2015. We cannot assure you that these facilities will become available. If we are not able to sell ethane, we may be required to curtail production which will adversely affect our revenues.

**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. At times, we have entered into basis swap agreements. The price we receive for our gas production can be more or less than the NYMEX price because of adjustments for delivery location ( basis ), relative quality and other factors; therefore, we have entered into basis swap agreements in the past that effectively fix the basis adjustments. We currently have no financial basis swap agreements outstanding.

Table of Contents

The following table shows the fair value of our collars, swaps, put and call options and the hypothetical change in fair value that would result from a 10% and a 25% change in commodity prices at September 30, 2012. We remain at risk for possible changes in the market value of commodity derivative instruments; however, such risks should be mitigated by price changes in the underlying physical commodity (in thousands):

| | | Hypothetical Change in Fair Value Increase of | | Hypothetical Change in Fair Value Decrease of | |
|---|---|---|---|---|---|
| | Fair Value | 10% | 25% | 10% | 25% |
| Collars | $ 109,629 | $ (92,408) | $ (232,482) | $ 92,916 | $ 235,577 |
| Call options | (3,732) | (3,696) | (9,622) | 2,677 | 3,677 |
| Swaps | 33,282 | (96,597) | (241,050) | 97,103 | 243,151 |
| Put options | 77 | (63) | (75) | 302 | 2,409 |

Our commodity-based contracts expose us to the credit risk of non-performance by the counterparty to the contracts. Our exposure is diversified among major investment grade financial institutions and we have master netting agreements with the majority of our counterparties that provide for offsetting payables against receivables from separate derivative contracts. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. At September 30, 2012, our derivative counterparties include sixteen financial institutions, of which all but two are secured lenders in our bank credit facility. Counterparty credit risk is considered when determining the fair value of our derivative contracts. While counterparties are major investment grade financial institutions, the fair value of our derivative contracts have been adjusted to account for the risk of non-performance by certain of our counterparties, which was immaterial.

**Interest Rate Risk**

We are exposed to interest rate risk on our bank debt. We attempt to balance variable rate debt, fixed rate debt and debt maturities to manage interest costs, interest rate volatility and financing risk. This is accomplished through a mix of fixed rate senior subordinated debt and variable rate bank debt. At September 30, 2012, we had $2.8 billion of debt outstanding. Of this amount, $2.4 billion bears interest at fixed rates averaging 6.4%. Bank debt totaling $461.0 million bears interest at floating rates, which was 1.8% on September 30, 2012. On September 30, 2012, the 30-day LIBOR rate was 0.2%. A 1% increase in short-term interest rates on the floating-rate debt outstanding on September 30, 2012, would cost us approximately $4.6 million in additional annual interest expense.

Table of Contents

**ITEM 4. CONTROLS AND PROCEDURES**

**Evaluation of Disclosure Controls and Procedures**

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Form 10-Q. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of September 30, 2012 at the reasonable assurance level.

**Changes in Internal Control over Financial Reporting**

There was no change in our system of internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the quarter ended September 30, 2012 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Table of Contents

**PART II OTHER INFORMATION**

**ITEM 1. LEGAL PROCEEDINGS**

We are the subject of, or party to, a number of pending or threatened legal actions and claims arising in the ordinary course of our business. While many of these matters involve inherent uncertainty, we believe that the amount of liability, if any, ultimately incurred with respect to proceedings or claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future annual results of operation.

**ITEM 1A. RISK FACTORS**

We are subject to various risks and uncertainties in the course of our business. In addition to the factors discussed elsewhere in this report, you should carefully consider the risks and uncertainties described under Item 1A. Risk Factors filed in our Annual Report on Form 10-K for the year ended December 31, 2011. There have been no material changes from the risk factors previously disclosed in that Form 10-K.

Table of Contents

**ITEM 6. EXHIBITS**
**(a) EXHIBITS**

| Exhibit Number | Exhibit Description |
|---|---|
| 3.1 | Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on May 5, 2004, as amended by the Certificate of Second Amendment to Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on July 28, 2005) and the Certificate of Second Amendment to the Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on July 24, 2008) |
| 3.2 | Amended and Restated By-laws of Range (incorporated by reference to Exhibit 3.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 20, 2010) |
| 31.1* | Certification by the 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 |
| 101. INS* | XBRL Instance Document |
| 101. SCH* | XBRL Taxonomy Extension Schema |
| 101. CAL* | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101. DEF* | XBRL Taxonomy Extension Definition Linkbase Document |
| 101. LAB* | XBRL Taxonomy Extension Label Linkbase Document |
| 101. PRE* | XBRL Taxonomy Extension Presentation Linkbase Document |

* filed herewith
** furnished herewith

**Table of Contents**

## SIGNATURES

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

Date: October 24, 2012

RANGE RESOURCES CORPORATION

By: /s/ ROGER S. MANNY

**Roger S. Manny**

***Executive Vice President and Chief Financial Officer***

Date: October 24, 2012

RANGE RESOURCES CORPORATION

By: /s/ DORI A. GINN

**Dori A. Ginn**

***Principal Accounting Officer and Vice President Controller***

II-1

Table of Contents

**Exhibit index**

| Exhibit<br>Number | Exhibit Description |
|---|---|
| 3.1 | Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on May 5, 2004, as amended by the Certificate of Second Amendment to Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on July 28, 2005) and the Certificate of Second Amendment to the Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on July 24, 2008) |
| 3.2 | Amended and Restated By-laws of Range (incorporated by reference to Exhibit 3.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 20, 2010) |
| 31.1* | Certification by the 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 |
| 101. INS* | XBRL Instance Document |
| 101. SCH* | XBRL Taxonomy Extension Schema |
| 101. CAL* | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101. DEF* | XBRL Taxonomy Extension Definition Linkbase Document |
| 101. LAB* | XBRL Taxonomy Extension Label Linkbase Document |
| 101. PRE* | XBRL Taxonomy Extension Presentation Linkbase Document |

* filed herewith
** furnished herewith