RANGE RESOURCES CORP
Form 10-Q
April 28, 2014

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 March 31, 2014

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	(IRS Employer
Incorporation or Organization)	Identification No.)
	76102
100 Throckmorton Street, Suite 1200	

Fort Worth, Texas
(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

163,879,524 Common Shares were outstanding on April 25, 2014

RANGE RESOURCES CORPORATION

FORM 10-Q

Quarter Ended March 31, 2014

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

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PART I – FINANCIAL INFORMATION

ITEM 1. Financial Statements
RANGE RESOURCES CORPORATION

CONSOLIDATED BALANCE SHEETS

(In thousands, except share data)

	March 31, 2014 (Unaudited)	December 31, 2013
Assets		
Current assets:		
Cash and cash equivalents	$246	$348
Accounts receivable, less allowance for doubtful accounts of $2,487 and $2,494	221,304	179,667
Derivative assets	80	4,421
Deferred tax asset	40,362	51,414
Inventory and other	17,353	12,451
Total current assets	279,345	248,301
Derivative assets	15,917	9,233
Equity method investments	123,791	129,034
Natural gas and oil properties, successful efforts method	9,309,743	9,032,881
Accumulated depletion and depreciation	(2,397,089)	(2,274,444)
	6,912,654	6,758,437
Transportation and field assets	120,036	118,625
Accumulated depreciation and amortization	(87,955)	(85,841)
	32,081	32,784
Other assets	118,987	121,297
Total assets	$7,482,775	$7,299,086
Liabilities		
Current liabilities:		
Accounts payable	$273,756	$258,431
Asset retirement obligations	5,037	5,037
Accrued liabilities	164,585	161,520
Accrued interest	32,303	44,375
Derivative liabilities	72,854	26,198
Total current liabilities	548,535	495,561
Bank debt	594,000	500,000
Subordinated notes	2,640,866	2,640,516
Deferred tax liability	778,955	771,980
Derivative liabilities	142	25
Deferred compensation liability	235,307	247,537
Asset retirement obligations and other liabilities	235,289	229,015
Total liabilities	5,033,094	4,884,634
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, 163,763,190 issued at March 31, 2014 and 163,441,414 issued at December 31, 2013	1,638	1,634
Common stock held in treasury, 93,275 shares at March 31, 2014 and 98,520 shares at December 31, 2013	(3,455)	(3,637)
Additional paid-in capital	1,969,948	1,959,636
Retained earnings	476,554	450,583
Accumulated other comprehensive income	4,996	6,236
Total stockholders’ equity	2,449,681	2,414,452
Total liabilities and stockholders’ equity	$7,482,775	$7,299,086

See accompanying notes.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited, in thousands, except per share data)

	Three Months Ended March 31,	
	2014	2013
Revenues and other income:		
Natural gas, NGLs and oil sales	$572,017	$398,239
Derivative fair value loss	(146,850)	(99,875)
Loss on the sale of assets	(353)	(166)
Brokered natural gas, marketing and other	32,528	21,041
Total revenues and other income	457,342	319,239
Costs and expenses:		
Direct operating	39,795	30,188
Transportation, gathering and compression	74,161	62,416
Production and ad valorem taxes	11,678	11,383
Brokered natural gas and marketing	34,129	22,315
Exploration	14,846	16,780
Abandonment and impairment of unproved properties	9,995	15,218
General and administrative	49,212	84,058
Deferred compensation plan	(2,035)	42,360
Interest expense	45,401	42,210
Depletion, depreciation and amortization	128,682	115,101
Total costs and expenses	405,864	442,029
Income (loss) from operations before income taxes	51,478	(122,790)
Income tax expense (benefit)		
Current	6	25
Deferred	18,951	(47,205)
	18,957	(47,180)
Net income (loss)	$32,521	$(75,610)
Net income (loss) per common share:		
Basic	$0.20	$(0.47)
Diluted	$0.20	$(0.47)
Dividends paid per common share	$0.04	$0.04
Weighted average common shares outstanding:		
Basic	160,794	160,125
Diluted	161,825	160,125

See accompanying notes.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(Unaudited, in thousands)

	Three Months Ended March 31,	
	2014	2013
Net income (loss)	$32,521	$(75,610)
Other comprehensive income (loss):		
Realized loss (gain) on hedge derivative contract settlements reclassified into natural gas, NGLs and oil sales from other comprehensive income, net of taxes [1]	—	(14,840)
De-designated hedges reclassified into natural gas, NGLs and oil sales, net of taxes [2]	(1,240)	(7,425)
De-designated hedges reclassified to derivative fair value income, net of taxes [3]	—	(1,390)
Change in unrealized deferred hedging (losses) gains, net of taxes [4]	—	(4,203)
Total comprehensive income (loss)	$31,281	$(103,468)

(1) Amounts are net of income tax benefit of $9,488 for the three months ended March 31, 2013.

(2) Amounts are net of income tax benefit of $924 for the three months ended March 31, 2014 and $4,747 for the three months ended March 31, 2013.

(3) Amounts relate to transactions not probable of occurring and are presented net of income tax benefit of $889 for the three months ended March 31, 2013.

(4) Amounts are net of income tax benefit of $2,687 for the three months ended March 31, 2013.

See accompanying notes.

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RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited, in thousands)

	Three Months Ended March 31, 2014	2013
Operating activities:		
Net income (loss)	$32,521	$(75,610)
Adjustments to reconcile net income (loss) to net cash provided from operating activities:		
Loss from equity method investments, net of distributions	2,732	610
Deferred income tax expense (benefit)	18,951	(47,205)
Depletion, depreciation and amortization	128,682	115,101
Exploration dry hole costs	1	(159)
Abandonment and impairment of unproved properties	9,995	15,218
Derivative fair value loss	146,850	99,875
Cash settlements on derivative financial instruments that do not qualify for hedge accounting	(104,584)	382
Amortization of deferred financing costs and other	2,873	2,080
Deferred and stock-based compensation	12,593	54,991
Loss on the sale of assets	353	166
Changes in working capital:		
Accounts receivable	(41,643)	1,292
Inventory and other	(5,358)	166
Accounts payable	9,997	17,061
Accrued liabilities and other	(32,742)	17,281
Net cash provided from operating activities	181,221	201,249
Investing activities:		
Additions to natural gas and oil properties	(226,331)	(259,601)
Additions to field service assets	(3,084)	(1,071)
Acreage purchases	(50,690)	(8,794)
Equity method investments	2,511	1,885
Proceeds from disposal of assets	294	38,196
Purchases of marketable securities held by the deferred compensation plan	(8,247)	(17,936)
Proceeds from the sales of marketable securities held by the deferred compensation plan	9,310	6,316
Net cash used in investing activities	(276,237)	(241,005)
Financing activities:		
Borrowing on credit facilities	412,000	368,000
Repayment on credit facilities	(318,000)	(1,060,000)
Issuance of subordinated notes	—	750,000
Dividends paid	(6,550)	(6,521)
Debt issuance costs	—	(12,098)
Issuance of common stock	—	343
Change in cash overdrafts	(1,122)	(12,458)
Proceeds from the sales of common stock held by the deferred compensation plan	8,586	12,432

Net cash provided from financing activities	94,914	39,698
Decrease in cash and cash equivalents	(102)	(58)
Cash and cash equivalents at beginning of period	348	252
Cash and cash equivalents at end of period	$246	$194

See accompanying notes.

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 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. 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 2013 Annual Report on Form 10-K filed on February 26, 2014. The results of operations for the first quarter ended March 31, 2014 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 (the "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 years reported amounts in order to conform with the current year presentation including reclassifications between accounts payable and accrued liabilities within cash flow from operating activities and a change in the presentation for our derivative activities. These reclassifications have no impact on previously reported net income, stockholders' equity or cash flows.

De-designation of Commodity Derivative Contracts

Effective March 1, 2013, we elected to discontinue hedge accounting prospectively. After March 1, 2013, both realized and unrealized gains and losses are recognized in derivative fair value income or loss immediately each quarter as derivative contracts are settled and marked to market. For additional information, see Note 11.

(3) NEW ACCOUNTING STANDARDS

Recently Adopted

In February 2013, an accounting standards update was issued to provide guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date, except for obligations such as asset retirement and environmental obligations, contingencies, guarantees, income taxes and retirement benefits, which are separately addressed within U.S. GAAP. An entity is required to measure obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date as the sum of (1) the amount the entity agreed to pay on the basis of its arrangement among its co-obligors and (2) any amount the entity expects to pay on behalf of its co-obligors. Disclosure of the nature of the obligation, including how the liability arose, the relationship with other co-obligors and the terms and conditions of the arrangement is required. In addition, the total outstanding amount under the arrangement, not reduced by the effect of any amounts that may be recoverable from other entities, plus the carrying amount of any liability or receivable recognized must be disclosed. This accounting standards update is effective for us beginning in first quarter 2014 and should be applied retrospectively for those in-scope obligations resulting from joint and several liability arrangements that exist at the beginning of 2014. Early adoption was permitted and we adopted this new standard in first quarter 2014 which did not have an impact on our consolidated results of operations, financial position or cash flows.

In April 2014, an accounting standards update was issued that raised the threshold for a disposal to qualify as a discontinued operation and requires new disclosures of both discontinued operations and certain other material disposal transactions that do not meet the revised definition of a discontinued operations. Under the updated standard, a disposal of a component or group of components of an entity is required to be reported as discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity’s operations and financial results when the component or group of components of the entity (1) has been disposed of by a sale, (2) has been disposed of other than by sale or (3) is classified as held for sale. This accounting standards update is effective for annual periods beginning on or after December 15, 2014 and is applied prospectively. Early adoption is permitted but only for disposals (or classifications that are held for sale) that have not been reported in financial statements previously issued or available for use. We adopted this new standard in first quarter 2014. There was no impact to our consolidated results of operations, financial position or cash flows as there were no disposals or assets held for sale in first quarter 2014.

(4) DISPOSITIONS

2014 Dispositions

In December 2013, we announced our plan to offer for sale certain of our properties in the Permian Basin. These properties included approximately 90,000 (70,000 net) acres, almost all of which are held by production in Glasscock and Sterling Counties and are currently producing approximately 28 Mmcfe per day. The data room opened in January 2014 and we received bids in late February. In late April, an agreement related to this transaction was executed, subject to board approval. The completion of this transaction is dependent upon continuing due diligence procedures and there can be no assurance the transaction will be completed. In first quarter 2014, we also sold miscellaneous unproved and proved properties for proceeds of $294,000 resulting in a pre-tax loss of $353,000.

2013 Dispositions

In first quarter 2013, we sold miscellaneous proved properties and inventory for proceeds of $38.2 million resulting in a pre-tax loss of $166,000.

(5) INCOME TAXES

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

	Three Months Ended March 31,	
	2014	2013
Income tax expense (benefit)	$18,957	$(47,180)
Effective tax rate	36.8 %	38.4 %

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 first quarter ended March 31, 2014 and 2013, our overall effective tax rate on operations was different than the federal statutory rate of 35% due primarily to state income taxes, valuation allowances and other permanent differences.

(6) 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 to diluted income or loss attributable to common shareholders (in thousands except per share amounts):

	Three Months Ended March 31,	
	2014	2013
Net income (loss), as reported	$32,521	$(75,610)
Participating basic earnings [(a)]	(560)	(109)
Basic net income (loss) attributed to common shareholders	31,961	(75,719)
Reallocation of participating earnings [(a)]	3	—
Diluted net income (loss) attributed to common shareholders	$31,964	$(75,719)
Net income (loss) per common share:		
Basic	$0.20	$(0.47)
Diluted	$ 0.20	$(0.47)

(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.

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 March 31,	
	2014	2013
Denominator:		
Weighted average common shares outstanding – basic	160,794	160,125
Effect of dilutive securities:		
Director and employee stock options and SARs	1,031	—
Weighted average common shares outstanding – diluted	161,825	160,125

Weighted average common shares – basic for the three months ended March 31, 2014 excludes 2.8 million shares and the three months ended March 31, 2013 excludes 2.7 million shares of restricted stock held in our deferred compensation plans (although all awards are issued and outstanding upon grant). Due to our loss from continuing operations for the three months ended March 31, 2013, we excluded all outstanding stock appreciation rights (“SARs”) and restricted stock from the computation of diluted net loss per share because the effect would have been anti-dilutive to the computations.

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(7) 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 three months ended March 31, 2014 and the year ended December 31, 2013 (in thousands except for number of projects):

	March 31, 2014	December 31, 2013
Balance at beginning of period	$ 6,964	$ 57,360
Additions to capitalized exploratory well costs pending the determination of proved reserves	5,552	39,832
Reclassifications to wells, facilities and equipment based on determination of proved reserves	—	(84,840)
Capitalized exploratory well costs charged to expense	—	—
Divested wells	—	(5,388)
Balance at end of period	12,516	6,964
Less exploratory well costs that have been capitalized for a period of one year or less	(5,552)	—
Capitalized exploratory well costs that have been capitalized for a period greater than one year	$ 6,964	$ 6,964
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	1	1

As of March 31, 2014, $7.0 million of capitalized exploratory well costs have been capitalized for more than one year which relates to one well in our Marcellus Shale area where we are evaluating pipeline options. The following table provides an aging of capitalized exploratory well costs that have been suspended for more than one year as of March 31, 2014 (in thousands):

	Total	2013	2012	2011
Capitalized exploratory well costs that have been capitalized for more than one year	$6,964	$110	$6,801	$ 53

(8) INDEBTEDNESS

We had the following debt outstanding as of the dates shown below (bank debt interest rate at March 31, 2014 is shown parenthetically) (in thousands). No interest was capitalized during the three months ended March 31, 2014 or the year ended December 31, 2013:

	March 31, 2014	December 31, 2013
Bank debt (1.9%)	$594,000	$ 500,000

Senior subordinated notes:		
8.00% senior subordinated notes due 2019, net of $9,134 and $9,484 discount, respectively	290,866	290,516
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
5.00% senior subordinated notes due 2023	750,000	750,000
Total debt	$ 3,234,866	$ 3,140,516

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 March 31, 2014, 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 April 3, 2014, 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 composed

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of twenty-eight financial institutions with no one bank holding more than 9% of the total facility. The bank credit 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 our payment of a mutually acceptable commitment fee to those banks. As of March 31, 2014, the outstanding balance under our bank credit facility was $594.0 million. Additionally, we had $127.4 million of undrawn letters of credit leaving $1.0 billion of borrowing capacity available under the facility. The bank credit facility matures on February 18, 2016. Borrowings under the bank credit facility can either be at the Alternate Base Rate (as defined in the bank credit facility) plus a spread ranging from 0.50% to 1.5% or LIBOR borrowings at the Adjusted LIBO Rate (as defined in the bank credit facility) 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 2.0% for the three months ended March 31, 2014 compared to 2.1% for the three months ended March 31, 2013. A commitment fee is paid on the undrawn balance based on an annual rate of 0.35% to 0.50%. At March 31, 2014, the commitment fee was 0.375% and the interest rate margin was 1.75% on our LIBOR loans and 0.75% on our base rate loans.

Senior Subordinated Notes

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, subject to certain customary release provisions. A subsidiary guarantor may be released from its obligations under the guarantee:

- in the event of a sale or other disposition of all or substantially all of the assets of the subsidiary guarantor or a sale or other disposition of all the capital stock of the subsidiary guarantor, to any corporation or other person (including an unrestricted subsidiary of Range) by way of merger, consolidation, or otherwise; or
- if Range designates any restricted subsidiary that is a guarantor to be an unrestricted subsidiary in accordance with the terms of the indenture.

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 are in compliance with our covenants under the bank credit facility at March 31, 2014.

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 March 31, 2014, we are in compliance with these covenants.

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(9) 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 three months ended March 31, 2014 is as follows (in thousands):

	Three Months Ended March 31, 2014
Beginning of period	$ 230,077
Liabilities incurred	2,128
Liabilities settled	(384)
Disposition of wells	(122)
Accretion expense	3,707
Change in estimate	1,089
End of period	236,495
Less current portion	(5,037)
Long-term asset retirement obligations	$ 231,458

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

(10) 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 2013:

	Three Months Ended March 31, 2014	Year Ended December 31, 2013
Beginning balance	163,342,894	162,514,098
SARs exercised	48,280	278,916
Restricted stock granted	74,553	401,122
Restricted stock units vested	198,943	119,480
Treasury shares issued	5,245	29,278
Ending balance	163,669,915	163,342,894

(11) 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 swaps or collars 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. The fair value of our derivative 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 loss of $53.4 million at March 31, 2014. These contracts expire monthly through December 2016. The following table sets forth our derivative volumes by year as of March 31, 2014:

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price
Natural Gas			
2014	Collars	447,500 Mmbtu/day	$ 3.84–$ 4.48
2015	Collars	145,000 Mmbtu/day	$ 4.07–$ 4.56
2014	Swaps	240,145 Mmbtu/day	$ 4.18
2015	Swaps	234,966 Mmbtu/day	$ 4.19
2016	Swaps	60,000 Mmbtu/day	$ 4.18
Crude Oil			
2014	Collars	2,000 bbls/day	$ 85.55–$ 100.00
2014	Swaps	9,169 bbls/day	$ 94.40
2015	Swaps	6,000 bbls day	$ 89.48
NGLs (C3-Propane)			
2014	Swaps	12,000 bbls/day	$ 1.02/gallon
NGLs (NC4-Normal butane)			
2014	Swaps	4,000 bbls/day	$ 1.34/gallon
NGLs (C5-Natural Gasoline)			
2014	Swaps	1,000 bbls/day	$ 2.11/gallon

Every derivative instrument is required to be recorded on the balance sheet as either an asset or a liability measured at its fair value. Through February 28, 2013, changes in the fair value of our derivatives that qualified for hedge accounting were 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 March 31, 2014, an unrealized pre-tax derivative gain of $8.1 million ($5.0 million after tax) was recorded in AOCI. See additional discussion below regarding the discontinuance of hedge accounting. 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 or loss.

For those derivative instruments that qualified or were designated for hedge accounting, settled transaction gains and losses were determined monthly, and were included as increases or decreases to natural gas, NGLs and oil sales in the period the hedged production was sold. Through February 28, 2013, we had elected to designate our commodity derivative instruments that qualified for hedge accounting as cash flow hedges. Natural gas, NGLs and oil sales include $2.2 million of gains in first quarter 2014 compared to gains of $36.5 million in the same period of 2013 related to settled hedging transactions. Any ineffectiveness associated with these hedge derivatives is reflected in derivative fair value income or 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 loss for the three months ended March 31, 2014 includes no ineffective gains or losses compared to a loss of $2.9 million in the three months ended March 31, 2013. During the three months ended March 31, 2013, we recognized a pre-tax gain of $2.3 million in derivative fair value loss as a result of the discontinuance of hedge accounting where we determined the transaction was probable not to occur primarily due to the sale of our Delaware and Permian Basin properties in New Mexico and West Texas.

Discontinuance of Hedge Accounting

Effective March 1, 2013, we elected to de-designate all commodity contracts that were previously designated as cash flow hedges and elected to discontinue hedge accounting prospectively. AOCI included $103.6 million ($63.2 million after tax) of unrealized net gains, representing the marked-to-market value of the effective portion of our cash flow hedges as of February 28, 2013. As a result of discontinuing hedge accounting, the marked-to-market values included in AOCI as of the de-designation date were frozen and will be reclassified into earnings in natural gas, NGLs and oil sales in future periods as the underlying hedged transactions occur. As of March 31, 2014, we expect to reclassify into earnings $8.1 million of unrealized net gains in the remaining months of 2014.

With the election to de-designate hedging instruments, all of our derivative instruments continue to be recorded at fair value with unrealized gains and losses recognized immediately in earnings rather than in AOCI. These marked-to-market adjustments will produce a degree of earnings volatility that can be significant from period to period, but such adjustments will have no cash flow impact relative to changes in market prices. The impact to cash flow occurs upon settlement of the underlying contract.

Basis Swap Contracts

At March 31, 2014, we had natural gas basis swap contracts that are not designated for hedge accounting, which lock in the differential between NYMEX and certain of our physical pricing options in Appalachia. These contracts are for 254,164 Mmbtu/day and settle monthly through March 2015. The fair value of these contracts was a loss of $3.7 million on March 31, 2014.

Derivative Assets and Liabilities

The combined fair value of derivatives included in the accompanying consolidated balance sheets as of March 31, 2014 and December 31, 2013 is summarized below. 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. The tables below provide additional information relating to our master netting arrangements with our derivative counterparties (in thousands):

		March 31, 2014		
		Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet
Derivative assets:				
Natural gas	–swaps	$8,347	$—	$ 8,347
	–collars	7,328	(584)	6,744
	–basis swaps	3,123	(3,123)	—
Crude oil	–swaps	1,179	(273)	906
NGLs	–C3 swaps	1,877	(1,877)	—
	–C4 swaps	3,159	(3,159)	—
		$25,013	$(9,016)	$ 15,997

	March 31, 2014		
	Gross Amounts of Recognized (Liabilities)	Gross Amounts Offset in the Balance Sheet	Net Amounts of (Liabilities) Presented in the Balance Sheet
Derivative (liabilities):			

Natural gas	–swaps	$(27,720)	$ —	$ (27,720)
	–collars	(26,738)	584	(26,154)
	–basis swaps	(6,762)	3,123	(3,639)
Crude oil	–swaps	(10,027)	273	(9,754)
	–collars	(972)	—	(972)
NGLs	–C3 swaps	(9,692)	1,877	(7,815)
	–C4 swaps	—	3,159	3,159
	–C5 swaps	(101)	—	(101)
		$(82,012)	$ 9,016	$ (72,996)

		December 31, 2013		
		Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet
Derivative assets:				
Natural gas	–swaps	$4,240	$(1,218)	$ 3,022
	–collars	16,057	(7,671)	8,386
	–basis swaps	7,686	(7,686)	—
Crude oil	–swaps	3,567	(1,321)	2,246
NGLs	–C3 swaps	826	(826)	—
	–C4 swaps	863	(863)	—
	–C5 swaps	121	(121)	—
		$33,360	$(19,706)	$ 13,654

		December 31, 2013		
		Gross Amounts of Recognized (Liabilities)	Gross Amounts Offset in the Balance Sheet	Net Amounts of (Liabilities) Presented in the Balance Sheet
Derivative (liabilities):				
Natural gas	–swaps	$(4,790)	$1,218	$ (3,572)
	–collars	(13,345)	7,671	(5,674)
	–basis swaps	(3,756)	7,686	3,930
Crude oil	–swaps	(4,711)	1,321	(3,390)
	–collars	(398)	—	(398)
NGLs	–C3 swaps	(18,172)	826	(17,346)
	–C4 swaps	(757)	863	106
	–C5 swaps	—	121	121
		$(45,929)	$19,706	$ (26,223)

The effects of our cash flow hedges (or those derivatives that previously qualified for hedge accounting) on AOCI in the accompanying consolidated balance sheets is summarized below (in thousands):

	Three Months Ended March 31,			
	Change in Hedge Derivative Fair Value		Realized Gain (Loss) Reclassified from OCI into Revenue [(a)]	
	2014	2013	2014	2013
Swaps	$ —	$125	$836	$8,047
Collars	—	(7,015)	1,328	30,732

Income taxes	—	2,687	(924)	(15,124)
	$ —	$(4,203)	$1,240	$23,655

(a) For realized gains upon derivative contract settlement, the reduction in AOCI is offset by an increase in revenues, NGLs and oil sales. For realized losses upon derivative contract settlement, the increase in AOCI is offset by a decrease in revenues. See additional discussion above regarding the discontinuance of hedge accounting.

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 March 31,					
	Gain (Loss) Recognized in Income (Non-hedge Derivatives)		Gain (Loss) Recognized in Income (Ineffective Portion)		Derivative Fair Value Income (Loss)	
	2014	2013	2014	2013	2014	2013
Swaps	$(44,073)	$(43,076)	$ —	$ (1,995)	$(44,073)	$(45,071)
Re-purchased swaps	—	1,185	—	—	—	1,185
Collars	(39,148)	(55,003)	—	(896)	(39,148)	(55,899)
Call options	(63,629)	(90)	—	—	(63,629)	(90)
Total	$(146,850)	$(96,984)	$ —	$ (2,891)	$(146,850)	$(99,875)

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(12) FAIR VALUE MEASUREMENTS

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

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

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

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

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

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

Fair Values – Recurring

We use a market approach for our recurring fair value measurements and endeavor to use the best information available. 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 March 31, 2014 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 March 31, 2014

Trading securities held in the deferred compensation plans	$67,119	$ —	$ —	$67,119
Derivatives –swaps	—	(32,979)	—	(32,979)
–collars	—	(20,381)	—	(20,381)
–basis swaps	—	(3,611)	(28)	(3,639)

	Fair Value Measurements at December 31, 2013 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, 2013
Trading securities held in the deferred compensation plans	$67,766	$ —	$ —	$ 67,766
Derivatives –swaps	—	(18,812)	—	(18,812)
–collars	—	2,314	—	2,314
–basis swaps	—	3,381	548	3,929

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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. As of March 31, 2014, we have four natural gas basis swaps categorized as Level 3 due to the forward price curve being unavailable for the regional sales point. We based the fair value on the most similar regional forward natural gas basis curve received from a third party pricing service along with assumed basis differentials based on historical trends.

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 first quarter 2014, interest and dividends were $274,000 and the mark-to-market adjustment was a gain of $429,000 compared to interest and dividends of $40,000 and mark-to-market gain of $1.6 million in the same period of the prior year.

Fair Values—Reported

The following table presents the carrying amounts and the fair values of our financial instruments as of March 31, 2014 and December 31, 2013 (in thousands):

	March 31, 2014		December 31, 2013	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Assets:				
Commodity swaps, collars and basis swaps	$15,997	$15,997	$13,654	$13,654
Marketable securities[a]	67,119	67,119	67,766	67,766
(Liabilities):				
Commodity swaps, collars and basis swaps	(72,996)	(72,996)	(26,223)	(26,223)
Bank credit facility[b]	(594,000)	(594,000)	(500,000)	(500,000)
Deferred compensation plan[c]	(262,123)	(262,123)	(271,738)	(271,738)
8.00% senior subordinated notes due 2019[b]	(290,866)	(313,875)	(290,516)	(319,500)
6.75% senior subordinated notes due 2020[b]	(500,000)	(540,000)	(500,000)	(541,250)
5.75% senior subordinated notes due 2021[b]	(500,000)	(535,625)	(500,000)	(530,625)
5.00% senior subordinated notes due 2022[b]	(600,000)	(611,250)	(600,000)	(588,750)
5.00% senior subordinated notes due 2023[b]	(750,000)	(759,375)	(750,000)	(732,188)

(a) Marketable securities, which are held in our deferred compensation plans, are actively traded on major exchanges. Refer to Note 13 for additional information.

(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. Refer to Note 8 for additional information.

(c) The fair value of our deferred compensation plan is updated on the closing price on the balance sheet date which is a Level 1 market value.

Our current assets and liabilities contain financial instruments, the most significant of which are trade accounts receivable and payable. 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 and expected incurrence of bad debt expense. Non-financial liabilities initially measured at fair value include asset retirement obligations. For additional information, see Note 9.

Concentrations of Credit Risk

As of March 31, 2014, 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 deemed necessary to limit our risk of loss. Our allowance for uncollectible receivables was $2.5 million at both March 31, 2014 and December 31, 2013. As of March 31, 2014, our derivative contracts consist of swaps and collars. Our exposure to credit risk 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 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 March 31, 2014, our derivative counterparties include fourteen financial institutions, of which all but two are secured lenders in our bank credit facility. At March 31, 2014, our net derivative assets include a net payable to these two counterparties that are not included in our bank credit facility of $3.8 million.

(13) 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. 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 our Amended and Restated 2005 Equity-Based Incentive Compensation Plan (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 of the Board of Directors 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.

In first quarter 2014, the Compensation Committee of the Board of Directors began granting performance share unit awards ("PSUs") under our 2005 Plan. The number of shares to be issued is determined by our total shareholder return compared to the total shareholder return of a predetermined group of peer companies over the performance period. The performance unit awards vest at the end of three years. The grant date fair value of the PSUs is determined using a Monte Carlo simulation and is recognized as stock-based compensation expense over the three-year performance period.

The Compensation Committee also grants restricted stock to certain employees and non-employee directors of the Board of Directors as part of their compensation. Upon grant of these restricted shares, which we refer to as restricted stock Liability Awards, the shares generally are placed in our deferred compensation plan and, upon vesting, employees are allowed to take withdrawals either in cash or in stock. 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 shares and receive dividends thereon. These Liability Awards are classified as a liability and are remeasured at fair value each reporting period. This mark-to-market adjustment is reported as deferred compensation plan expense in the accompanying consolidated statements of operations.

Total Stock-Based Compensation Expense

Stock-based compensation represents amortization of restricted stock, PSUs and SARs expense. Unlike the other forms of stock-based compensation, 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. The following table details the allocation of stock-based compensation that is allocated to functional expense categories (in thousands):

	Three Months Ended March 31,	
	2014	2013
Operating expense	$852	$661

Brokered natural gas and marketing expense	528	249
Exploration expense	1,153	1,070
General and administrative expense	11,604	10,306
Total	$ 14,137	$ 12,286

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Stock Appreciation Right Awards

We have two active equity-based stock plans, the 2005 Plan and the 2004 Non-Employee Director Stock Option Plan. Under these plans, incentive and non-qualified stock options, SARs, restricted stock units and various other awards may be issued to non-employee directors and employees pursuant to decisions of the Compensation Committee, which is comprised of only non-employee, independent directors. Of the 2.4 million grants outstanding at March 31, 2014, all are grants relating to SARs. Information with respect to SARs activity is summarized below:

	Shares	Weighted Average Exercise Price
Outstanding at December 31, 2013	2,582,074	$ 56.36
Granted	1,104	81.74
Exercised	(137,271)	45.45
Expired/forfeited	—	—
Outstanding at March 31, 2014	2,445,907	$ 56.98

During first three months 2014, we granted SARs to our non-executive chairman in conjunction with his retirement from Range as an employee. The weighted average grant date fair value of these SARs, based on our Black-Scholes-Merton assumptions, is shown below:

	Three Months Ended March 31, 2014		
Weighted average exercise price per share	$	81.74	
Expected annual dividends per share		0.20	%
Expected life in years		4.3	
Expected volatility		33	%
Risk-free interest rate		1.4	%
Weighted average grant date fair value	$	23.17	

Performance Share Unit Awards

A summary of our performance share unit awards (“PSUs”) outstanding at March 31, 2014 is summarized below:

	Number of Units [(a)]	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2013	—	$ —

Units granted	57,421	82.60
Outstanding at March 31, 2014	57,421	$ 82.60

[(a)] These amounts reflect the number of performance units granted. The actual payout of shares may be between zero percent and 150% of the performance units granted depending on the total shareholder return ranking compared to the peer companies at the vesting date.

The following assumptions were used to estimate the fair value of PSUs granted during the first three months 2014:

	Three Months Ended March 31, 2014
Risk-free interest rate	0.71 %
Expected annual volatility	34 %
Grant date fair value per unit	$ 82.60

We recorded PSU compensation expense of $533,000 in the first three months 2014 compared to none in the same period of 2013.

Restricted Stock Awards

Equity Awards

In first three months 2014, we granted 351,000 restricted stock Equity Awards to employees at an average grant price of $84.89 compared to 386,000 restricted stock Equity Awards granted to employees at an average grant price of $71.02 in the same period of 2013. These awards generally vest over a three-year period. We recorded compensation expense for these Equity Awards of $6.5 million in the first three months 2014 compared to $4.3 million in the same period of 2013. Equity Awards are not issued to employees until they are vested. Employees do not have the option to receive cash.

Liability Awards

In first three months 2014, we granted 76,000 shares of restricted stock Liability Awards as compensation to employees at an average price of $85.02 with vesting generally over a three-year period. We also granted 950 shares at an average price of $81.74 to a director, which vested immediately. In the same period of 2013, we granted 125,000 shares of Liability Awards as compensation to employees at an average price of $71.40 with vesting generally over a three-year period. We recorded compensation expense for Liability Awards of $4.7 million in first three months 2014 compared to $4.5 million in the same period of 2013. 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 as deferred compensation expense in our consolidated statements of operations (see additional discussion below).

A summary of the status of our non-vested restricted stock and restricted stock units outstanding at March 31, 2014 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, 2013	385,063	$ 68.24	389,013	$ 71.02
Granted	350,594	84.89	77,435	84.98
Vested	(93,241)	69.86	(77,142)	69.55
Forfeited	(1,418)	79.41	(90)	71.03
Outstanding at March 31, 2014	640,998	$ 77.09	389,216	$ 74.09

Deferred Compensation Plan

Our deferred compensation plan gives non-employee 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 general 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 as 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 as 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 income of $2.0 million in first quarter 2014 compared to mark-to-market loss of $42.4 million in first quarter 2013. The Rabbi Trust held 2.8 million shares (2.4 million of vested shares) of Range stock at March 31, 2014 compared to 2.8 million shares (2.4 million of vested shares) at December 31, 2013.

(14) SUPPLEMENTAL CASH FLOW INFORMATION

	Three Months Ended March 31,	
	2014	2013
	(in thousands)	
Net cash provided from operating activities included:		
Income taxes (refunded) paid to taxing authorities	$39	$(162)
Interest paid	55,190	37,541
Non-cash investing and financing activities included:		
Asset retirement costs capitalized, net	3,218	1,690
Increase in accrued capital expenditures	6,808	128,136

(15) COMMITMENTS AND CONTINGENCIES

Litigation

We are the subject of, or party to, a number of pending or threatened legal actions, administrative proceedings 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 quarterly and will establish and adjust any litigation reserves as appropriate to reflect our assessment of the then current status of litigation.

Transportation and Gathering Contracts

In the three months ended March 31, 2014, our transportation and gathering commitments increased by approximately $628.4 million over the next 25 years primarily due to two new firm transportation contracts. In addition, we have entered into additional agreements which are contingent on certain pipeline and gathering modifications and/or construction, that will range between five and fifteen year terms and are expected to begin in late 2014 through 2017. Based on these new contracts, we will have transportation and gathering obligations for a range of natural gas volumes from 25,000 mcf per day to 300,000 mcf per day through the end of the contract term.

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

	March 31, 2014	December 31, 2013
	(in thousands)	
Natural gas and oil properties:		
Properties subject to depletion	$8,467,064	$8,225,859
Unproved properties	842,679	807,022
Total	9,309,743	9,032,881

Accumulated depreciation, depletion and amortization	(2,397,089)	(2,274,444)
Net capitalized costs	$ 6,912,654	$ 6,758,437

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

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

	Three Months Ended March 31, 2014	Year Ended December 31, 2013
	(in thousands)	
Acreage purchases	$48,597	$ 137,538
Development	223,912	938,668
Exploration:		
Drilling	7,737	189,742
Expense	13,694	60,384
Stock-based compensation expense	1,153	4,025
Gas gathering facilities:		
Development	3,618	47,086
Subtotal	298,711	1,377,443
Asset retirement obligations	3,218	76,373
Total costs incurred	$ 301,929	$ 1,453,816

[a] Includes cost incurred whether capitalized or expensed.

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," " "should," "would" or similar words indicating that future outcomes are uncertain. In accordance with "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, which could cause future outcomes to differ materially from those set forth in 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 set forth in our Annual Report on Form 10-K for the year ended December 31, 2013, as filed with the SEC on February 26, 2014.

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. We track only basic operational data by area.

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, crude oil and condensate and on our ability to economically find, develop, acquire and produce natural gas, NGLs and crude oil reserves. Prices for natural gas, NGLs and oil fluctuate widely and affect:

- the amount of cash flows available for capital expenditures;
- our ability to borrow and raise additional capital; and
- the quantity of natural gas, NGLs and oil we can economically produce.

We prepare our financial statements in conformity with generally accepted accounting principles, which require us to make estimates and assumptions that affect our reported results of operations and the amount of our reported assets, liabilities and proved natural gas, NGLs and oil reserves. We use the successful efforts method of accounting for our natural gas, NGLs and oil activities.

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 New York Mercantile Exchange ("NYMEX") prices for natural gas and oil and the Mont Belvieu NGL composite price for the three months ended March 31, 2014 and 2013:

	Three Months Ended March 31,	
	2014	2013

Average NYMEX prices [a]		
Natural gas (per mcf)	$ 4.89	$ 3.35
Oil (per bbl)	$ 98.61	$ 94.25
Mont Belvieu NGL Composite (per gallon)	$ 0.91	$ 0.78

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

Consolidated Results of Operations

Overview of First Quarter 2014 Results

During first quarter 2014, we achieved the following financial and operating results:

increased revenue from the sale of natural gas, NGLs and oil by 44% from the same period of 2013;

- achieved 21% production growth over the same period of 2013;
- continued expansion of our activities in the Marcellus Shale in Pennsylvania by growing production, proving up acreage and acquiring additional unproved acreage;
- excluding workovers, our direct operating expenses per mcfe remained flat from the same period of 2013;
- reduced our depletion, depreciation and amortization ("DD&A") rate 8% over the same period of 2013;
- entered into additional derivative contracts for 2014, 2015 and 2016; and
- realized $181.2 million of cash flow from operating activities.

Our first quarter 2014 net income was $32.5 million, or $0.20 per diluted common share compared to a net loss of $75.6 million, or a loss of $0.47 per diluted common share in the same period 2013. During first quarter 2014, we had an increase in revenue from the sale of natural gas, NGLs and oil driven by higher production volumes of 21%. Our first quarter 2014 production growth was due to the continued success of our drilling program, particularly in the Marcellus Shale. First quarter 2014 production for NGLs increased 137% from the same period of 2013 due to our sales of ethane based on our new ethane sales/transport agreements which commenced initial deliveries in late 2013. When comparing first quarter 2014 to the same period of 2013, we also experienced a favorable increase in our non-cash mark-to-market related to our deferred compensation plans along with favorable non-cash fair value adjustments on our commodity derivatives, a non-GAAP measure and lower general and administrative expense, all of which were somewhat offset by lower realized prices. Realized prices include the impact of basis differentials. Average natural gas differentials were $0.66 per mcf above NYMEX in the first quarter 2014 compared to $0.15 per mcf above NYMEX in the same quarter 2013. This increase was more than offset by realized losses on our basis hedging in the first quarter 2014 of $0.90 per mcfe.

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 2014 and for 2015 and 2016, 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.

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 qualified 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 the derivative fair value loss discussion below. Effective March 1, 2013, we elected to de-designate all commodity contracts that were previously designated as cash flow hedges and elected to discontinue hedge accounting prospectively. Refer to Note 11 to the consolidated financial statements for more information.

In first quarter 2014, natural gas, NGLs and oil sales increased 44% compared to the same period of 2013 with a 21% increase in production and a 19% increase in realized prices. The following table illustrates the primary components of natural gas, NGLs, crude oil and condensate sales for the three months ended March 31, 2014 and 2013 (in thousands):

	Three Months Ended March 31,			
	2014	2013	Change	% Change
Natural gas, NGLs and oil sales				
Gas wellhead	$346,226	$217,088	$129,138	59 %
Gas hedges realized [a]	1,168	35,478	(34,310)	(97 %)
Total gas revenue	$347,394	$252,566	$94,828	38 %
Total NGLs revenue	$ 135,504	$67,571	$ 67,933	101 %
Oil and condensate wellhead	$ 88,121	$77,080	$ 11,041	14 %
Oil hedges realized [a]	998	1,022	(24)	(2 %)
Total oil and condensate revenue	$ 89,119	$78,102	$11,017	14 %
Combined wellhead	$ 569,851	$361,739	$208,112	58 %
Combined hedges [a]	2,166	36,500	(34,334)	(94 %)
Total natural gas, NGLs and oil sales	$ 572,017	$398,239	$173,778	44 %

[a] Cash settlements related to derivatives that qualified or were historically designated for hedge accounting.

Our production continues to grow through drilling success as we place new wells on production partially offset by the natural decline of our natural gas and oil wells and asset sales. When compared to the same period of 2013, our first quarter 2014 production volumes increased 25% in our Appalachian region and decreased 5% in our Southwestern region. When compared to the same period of 2013, our Marcellus production volumes increased 29% for the first quarter. The decline in natural gas production volumes is primarily related to the increased sales of ethane, the extraction of which reduces natural gas volumes to be sold and, to a lesser extent, adverse weather conditions during first quarter 2014. Ethane production volumes are reported with NGLs in the table below. Our production for the three months ended March 31, 2014 and 2013 is set forth in the following table:

	Three Months Ended March 31,			
	2014	2013	Change	% Change
Production [a]				
Natural gas (mcf)	62,017,581	62,023,956	(6,375)	%
NGLs (bbls)	4,471,481	1,889,424	2,582,057	151 %
Crude oil and condensate (bbls)	1,035,145	912,662	122,483	13 %
Total (mcfe) [b]	95,057,337	78,836,472	16,220,865	21 %
Average daily production [a]				
Natural gas (mcf)	689,084	689,155	(71)	%
NGLs (bbls)	49,683	20,994	28,689	137 %
Crude oil and condensate (bbls)	11,502	10,141	1,361	13 %
Total (mcfe) [b]	1,056,193	875,961	180,232	21 %

[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 between oil and natural gas prices.

Our average realized price (including all derivative settlements and third-party transportation costs) received during first quarter 2014 was $4.14 per mcfe compared to $4.26 per mcfe in the same period of 2013. Because we record transportation costs on two separate bases, as required by U.S. 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 qualified for hedge accounting. Average sales prices (wellhead) do not include derivative settlements or third party transportation costs which are 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 from purchasers. Average realized price calculations for the three months ended March 31, 2014 and 2013 are shown below:

	Three Months Ended March 31,	
	2014	2013
Average Prices		
Average sales prices (wellhead):		
Natural gas (per mcf)	$ 5.58	$ 3.50
NGLs (per bbl)	30.30	35.76
Crude oil and condensate (per bbl)	85.13	84.46
Total (per mcfe) [(a)]	5.99	4.59
Average realized prices (including derivative settlements that qualified for hedge accounting):		
Natural gas (per mcf)	$ 5.60	$ 4.07
NGLs (per bbl)	30.30	35.76
Crude oil and condensate (per bbl)	86.09	85.58
Total (per mcfe) [(a)]	6.02	5.05
Average realized prices (including all derivative settlements):		
Natural gas (per mcf)	$ 4.20	$ 4.09
NGLs (per bbl)	27.34	35.29
Crude oil and condensate (per bbl)	82.03	85.46
Total (per mcfe) [(a)]	4.92	5.06
Average realized prices (including all derivative settlements and third party transportation costs paid by Range):		
Natural gas (per mcf)	$ 3.14	$ 3.14
NGLs (per bbl)	25.35	33.61
Crude oil and condensate (per bbl)	82.03	85.46
Total (per mcfe) [(a)]	4.14	4.26

[(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 between oil and natural gas prices.

Derivative fair value loss was $146.9 million in first quarter 2014 compared to $99.9 million in the same period of 2013. Through February 28, 2013, some of our derivatives did not qualify for hedge accounting and were accounted for using the mark-to-market accounting method whereby all realized and unrealized gains and losses related to these contracts are included in derivative fair value income or loss in the accompanying consolidated statements of operations. Effective March 1, 2013, we discontinued hedge accounting prospectively. Since March 1, 2013, all of our derivatives are accounted for using the mark-to-market accounting method. 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.

Loss on the sale of assets was $353,000 in first quarter 2014 compared to a loss of $166,000 in the same period of 2013. In first quarter 2014 and 2013, we sold miscellaneous proved and unproved oil and gas properties and inventory for proceeds received of $294,000 in first quarter 2014 compared to $38.2 million in the same period of 2013.

Brokered natural gas, marketing and other revenue in first quarter 2014 was $32.5 million compared to $21.0 million in the same period of 2013. The first three months 2014 includes a loss from equity method investments of $133,000 and $33.2 million of revenue from marketing and the sale of brokered gas. The first three months 2013 includes loss from equity method investments of $80,000 and $21.1 million of revenue from marketing and the sale of brokered gas. These revenues increased due to an increase in brokered volumes.

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 ended March 31, 2014 and 2013:

	Three Months Ended March 31, (per mcfe)				
	2014	2013	Change	% Change	
Direct operating expense	$0.42	$0.38	$0.04	11	%
Production and ad valorem tax expense	0.12	0.14	(0.02)	(14	%)
General and administrative expense	0.52	1.07	(0.55)	(51	%)
Interest expense	0.48	0.54	(0.06)	(11	%)
Depletion, depreciation and amortization expense	1.35	1.46	(0.11)	(8	%)

Direct operating expense was $39.8 million in first quarter 2014 compared to $30.2 million in the same period of 2013. 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. Our production volumes increased 21% but, on an absolute basis, our spending for direct operating expenses for first quarter 2014 increased 32% with an increase in the number of producing wells, higher workover costs, higher water handling and winter operations costs somewhat offset by the sale of certain non-core assets at the beginning of second quarter 2013. We incurred $5.6 million of workover costs in first quarter 2014 compared to $1.4 million of workover costs in the same period of 2013.

On a per mcfe basis, direct operating expense in first quarter 2014 increased 11% from the same period of 2013 with the increase consisting of higher workover costs. We expect to experience lower costs per mcfe as we increase production from our Marcellus Shale wells due to their lower operating cost relative to our other operating areas. However, our 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 expenses per mcfe are expected to increase. The following table summarizes direct operating expenses per mcfe for the three months ended March 31, 2014 and 2013:

	Three Months Ended March 31, (per mcfe)				
	2014	2013	Change	% Change	
Lease operating expense	$0.35	$0.35	$ ¾	¾	%
Workovers	0.06	0.02	0.04	200	%
Stock-based compensation (non-cash)	0.01	0.01	¾	¾	%
Total direct operating expense	$ 0.42	$0.38	$ 0.04	11	%

Production and ad valorem taxes are paid based on market prices, not hedged prices. This expense category also includes the Pennsylvania impact fee that was initially assessed in 2012. Production and ad valorem taxes (excluding the impact fee) were $5.2 million in first quarter 2014 compared to $4.2 million in the same period of 2013. On a per mcfe basis, production and ad valorem taxes (excluding the impact fee) was $0.05 in both first quarter 2014 and first quarter 2013 with an increase in volumes not subject to production taxes more than offset by higher prices. 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 first quarter 2014 is a $6.5 million impact fee ($0.07 per mcfe) compared to $7.1 million ($0.09 per mcfe) in the same period of the prior year.

General and administrative ("G&A") expense was $49.2 million in first quarter 2014 compared to $84.1 million for the same period of 2013. The first quarter 2014 decrease of $34.8 million when compared to 2013 is primarily due to lower lawsuit settlements. The first quarter 2013 included an accrual of $35.0 million related to an Oklahoma lawsuit that was settled in second quarter 2013 for $87.5 million. Stock-based compensation expense represents the amortization of restricted stock grants and performance shares granted to our employees and non-employee directors as part of compensation. On a per mcfe basis, G&A expense decreased 51% from first quarter 2013 primarily due to the settlement of the Oklahoma lawsuit which was partially accrued in first quarter 2013 and lower salaries and benefits. The following table summarizes general and administrative expenses per mcfe for the three months ended March 31, 2014 and 2013:

	Three Months Ended March 31, (per mcfe)			
	2014	2013	Change	% Change
General and administrative	$0.40	$0.50	$(0.10)	(20%)
Oklahoma legal settlement	¾	0.44	(0.44)	(100%)
Stock-based compensation (non-cash)	0.12	0.13	(0.01)	(8%)
Total general and administrative expenses	$ 0.52	$1.07	(0.55)	(51%)

Interest expense was $45.4 million for first quarter 2014 compared to $42.2 million for first quarter 2013. The following table presents information about interest expense per mcfe for the three months ended March 31, 2014 and 2013:

	Three Months Ended March 31, (per mcfe)			
	2014	2013	Change	% Change
Bank credit facility	$0.05	$0.06	$(0.01)	(17%)
Subordinated notes	0.41	0.45	(0.04)	(9%)
Amortization of deferred financing costs and other	0.02	0.03	(0.01)	(33%)
Total interest expense	$0.48	$0.54	(0.06)	(11%)

On an absolute basis, the increase in interest expense for first quarter 2014 from the same period of 2013 was primarily due to an increase in outstanding debt balances. In March 2013, we issued $750.0 million of 5.0% senior subordinated notes due 2023. We used the proceeds to repay our outstanding bank debt which carries a lower interest rate. We used the proceeds to repay $350.0 million of our outstanding credit facility balance and for general corporate purposes. The 2013 note issuance was 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 first quarter 2014 was $611.8 million compared to $685.6 million in the same period of 2013 and the weighted average interest rate on the bank credit facility was 2.0% in first quarter 2014 compared to 2.1% in the same period of 2013.

Depletion, depreciation and amortization ("DD&A") was $128.7 million in first quarter 2014 compared to $115.1 million in the same period of 2013. The increase in first quarter 2014 when compared to the same period of 2013 is due to a 7% decrease in depletion rates more than offset by a 21% increase in production. Depletion expense, the largest component of DD&A, was $1.28 per mcfe in first quarter 2014 compared to $1.38 per mcfe in the same period of 2013. 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. Our depletion rate per mcfe continues to decline due to our drilling success in the Marcellus Shale. The following table summarizes DD&A expense per mcfe for the three months ended March 31, 2014 and 2013:

Three Months Ended March 31,
(per mcfe)

	2014	2013	Change	% Change
Depletion and amortization	$ 1.28	$1.38	$ (0.10)	(7 %)
Depreciation	0.03	0.05	(0.02)	(40 %)
Accretion and other	0.04	0.03	0.01	33 %
Total DD&A expense	$ 1.35	$1.46	$ (0.11)	(8 %)

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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 expense, brokered natural gas and marketing expense, exploration expense, abandonment and impairment of unproved properties and deferred compensation plan expense. Stock-based compensation includes the amortization of restricted stock grants, PSUs and SARs grants. The following table details the allocation of stock-based compensation that is allocated to functional expense categories for the three months ended March 31, 2014 and 2013 (in thousands):

	Three Months Ended March 31,	
	2014	2013
Direct operating expense	$ 852	$ 661
Brokered natural gas and marketing expense	528	249
Exploration expense	1,153	1,070
General and administrative expense	11,604	10,306
Total stock-based compensation	$ 14,137	$ 12,286

Transportation, gathering and compression expense was $74.2 million in first quarter 2014 compared to $62.4 million in the same period of 2013. These third party costs are higher than 2013 due to our production growth in the Marcellus Shale where we have third party gathering, compression and transportation agreements. First quarter 2014 also includes the impact of an ethane transportation contract. We have included these costs in the calculation of average realized prices (including all derivative settlements and third party transportation expenses paid by Range).

Brokered natural gas and marketing expense was $34.1 million in first quarter 2014 compared to $22.3 million in the same period of 2013. These costs are higher than 2013 primarily due to an increase in brokered volumes.

Exploration expense was $14.8 million in first quarter 2014 compared to $16.8 million in the same period of 2013 due to lower seismic costs and delay rental payments. The following table details our exploration related expenses for the three months ended March 31, 2014 and 2013 (in thousands):

	Three Months Ended March 31,			
	2014	2013	Change	% Change
Seismic	$ 5,245	$ 7,168	$ (1,923)	(27%)
Delay rentals and other	4,094	5,050	(956)	(19%)
Personnel expense	4,353	3,651	702	19%
Stock-based compensation expense	1,153	1,070	83	8%
Dry hole expense	1	(159)	160	(101%)
Total exploration expense	$ 14,846	$ 16,780	$ (1,934)	(12%)

Abandonment and impairment of unproved properties was $10.0 million in first quarter 2014 compared to $15.2 million in the same period of 2013. 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 decline in first quarter 2014 when compared to the same quarter of 2013 is primarily due to lower expected forfeiture rates in the Marcellus Shale.

Deferred compensation plan expense was a gain of $2.0 million in first quarter 2014 compared to a loss of $42.4 million in the same period of 2013. 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 decreased from $84.31 at December 31, 2013 to $82.97 at March 31, 2014. In the same quarter of the prior year, our stock price increased from $62.83 at December 31, 2012 to $81.04 at March 31, 2013.

Income tax expense (benefit) was an expense of $19.0 million in first quarter 2014 compared to a benefit of $47.2 million in first quarter 2013. The increase in income taxes in first quarter 2014 reflects a 142% increase in income from operations when compared to the same period of 2013. For the first quarter, the effective tax rate was 36.8% in 2014 compared to 38.4% in 2013. The 2014 and 2013 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 deferred tax assets associated with senior executives to the extent their estimated future compensation, which includes distributions from the deferred compensation plan, is expected to 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 39% for the remainder of 2014, before any discrete tax items.

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

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 March 31, 2014, we have entered into hedging agreements covering 234.5 Bcfe for the remainder of 2014, 151.8 Bcfe for 2015 and 22.0 Bcfe for 2016. We have also entered into basis hedges for 254,164 Mmbtu/day through March 2015.

Net cash provided from operations in the first three months 2014 was $181.2 million compared to $201.2 million in the same period of 2013. Cash provided from continuing operations is largely dependent upon commodity prices and production volumes, net of the effects of settlement of our derivative contracts. The decrease in cash provided from operating activities from 2013 to 2014 reflects a 21% increase in production offset by lower realized prices (a decline of 3%), higher operating costs and unfavorable working capital. As of March 31, 2014, we have hedged approximately 78% of our projected production for the remainder of 2014, with approximately 89% of our projected natural gas production hedged. Net cash provided from continuing operations is 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 three months 2014 was negative $69.7 million compared to positive $35.8 million for the same period of 2013. The prior year working capital was impacted by a lawsuit settlement accrual of $35.0 million.

Net cash used in investing activities from operations in first three months 2014 was $276.2 million compared to $241.0 million in the same period of 2013.

During the three months ended March 31, 2014, we:

spent $226.3 million on natural gas and oil property additions;
spent $50.7 million on acreage, primarily in the Marcellus Shale; and
received proceeds from asset sales of $294,000.

During the three months ended March 31, 2013, we:

spent $259.6 million on natural gas and oil property additions;

- spent $8.8 million on acreage primarily in the Marcellus Shale; and
- received proceeds from asset sales of $38.2 million.

Net cash provided from financing activities in first three months 2014 was $94.9 million compared to $39.7 million in the same period of 2013. Historically, sources of financing have been primarily bank borrowings and capital raised through equity and debt offerings.

During the three months ended March 31, 2014, we:

- borrowed $412.0 million and repaid $318.0 million under our bank credit facility, ending the quarter with a $594.0 million outstanding balance on our bank debt.

During the three months ended March 31, 2013, we:

- borrowed $368.0 million and repaid $1.1 billion under our bank credit facility, ending the quarter with $47.0 million outstanding borrowings under our bank credit facility; and
- issued $750.0 million principal amount of 5.00% senior subordinated notes due 2023, at par, with net proceeds of approximately $738.8 million.

Liquidity and Capital Resources

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 must find new reserves and develop existing reserves to maintain and grow our production and cash flows. We accomplish this primarily through successful drilling programs which require substantial capital expenditures. We continue to take steps to ensure adequate capital resources and liquidity to fund our capital expenditure program. In first three months 2014, we entered into additional commodity derivative contracts for 2014, 2015 and 2016 to protect future cash flows. On April 3, 2014, our borrowing base and our credit facility amounts were reaffirmed.

During first three months 2014, our net cash provided from operating activities of $181.2 million and borrowing under our bank credit facility were used to fund $280.1 million of capital expenditures (including acreage acquisitions). At March 31, 2014, we had $246,000 in cash and total assets of $7.5 billion.

Long-term debt at March 31, 2014 totaled $3.2 billion, including $594.0 million outstanding on our bank credit facility and $2.6 billion of senior subordinated notes. Our available committed borrowing capacity at March 31, 2014 was $1.0 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 contracts currently in place will be adequate to satisfy near-term 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 securities 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 establish a capital budget at the beginning of each calendar year and review it during the course of the year. Our 2014 capital budget is $1.52 billion. 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.

Credit Arrangements

As of March 31, 2014, 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 3, 2014, the facility amount on our bank credit facility was reaffirmed at $1.75 billion and our borrowing base was reaffirmed at $2.0

billion. Our current bank group is currently composed 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 are in compliance with all covenants at March 31, 2014.

Cash Dividend Payments

On March 1, 2014, the Board of Directors declared a dividend of four cents per share ($6.6 million) on our common stock, which was paid on March 31, 2014 to stockholders of record at the close of business on March 14, 2014. The amount of future dividends is subject to declaration by the Board of Directors and primarily depends on earnings, capital expenditures, debt covenants and various other factors.

Cash Contractual Obligations

Our contractual obligations include long-term debt, operating leases, drilling commitments, derivative obligations, asset retirement obligations and transportation and gathering commitments. As of March 31, 2014, we do not have any capital leases. As of March 31, 2014, 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 March 31, 2014, we had a total of $127.4 million of undrawn letters of credit under our bank credit facility.

Since December 31, 2013, there have been no material changes to our contractual obligations other than a $94.0 million increase in our outstanding bank credit facility balance and new transportation contracts which increased these commitments by approximately $628.4 million over the next 25 years.

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 and collar 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. 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 on-going development drilling and production enhancement programs, more consistent returns on invested capital, and better access to bank and other credit markets. 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 loss of $53.4 million at March 31, 2014. The contracts expire monthly through December 2016. At March 31, 2014, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price
Natural Gas			
2014	Collars	447,500 Mmbtu/day	$3.84–$ 4.48
2015	Collars	145,000 Mmbtu/day	$4.07–$ 4.56
2014	Swaps	240,145 Mmbtu/day	$4.18
2015	Swaps	234,966 Mmbtu/day	$4.19
2016	Swaps	60,000 Mmbtu/day	$4.18
Crude Oil			