RANGE RESOURCES CORP
Form 10-K
February 24, 2015

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

(Mark one)

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 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 Incorporation or Organization)	(IRS Employer Identification No.)
100 Throckmorton Street, Suite 1200, Fort Worth, Texas	76102
(Address of Principal Executive Offices)	(Zip Code)

Registrant's telephone number, including area code

(817) 870-2601

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of each exchange on which registered
Common Stock, $.01 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No x

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 x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, 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 such shorter period that the registrant was required to submit and post such files). Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

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

Large accelerated filer x	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a 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 Act). Yes ¨ No x

The aggregate market value of the voting and non-voting common equity held by non-affiliates as of June 30, 2014 was $14,270,959,000. This amount is based on the closing price of registrant's common stock on the New York Stock Exchange on that date. Shares of common stock held by executive officers and directors of the registrant are not included in the computation. However, the registrant has made no determination that such individuals are "affiliates" within the meaning of Rule 405 of the Securities Act of 1933.

As of February 23, 2015, there were 168,909,287 shares of Range Resources Corporation Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement to be furnished to stockholders in connection with its 2015 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year to which this report relates, are incorporated by reference in Part III, Items 10-14 of this report.

RANGE RESOURCES CORPORATION

Unless the context otherwise indicates, all references in this report to “Range,” “we,” “us” or “our” are to Range Resources Corporation and its directly and indirectly owned subsidiaries and its ownership interests in equity method investments. Unless otherwise noted, all information in the report relating to natural gas, natural gas liquids and oil reserves and the estimated future net cash flows attributable to those reserves are based on estimates and are net to our interest. If you are not familiar with the oil and gas terms used in this report, please refer to the explanation of such terms under the caption “Glossary of Certain Defined Terms” at the end of Item 15 of this report.

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Disclosures Regarding Forward-Looking Statements

This Annual Report on Form 10-K, particularly Item 1. and 2. Business and Properties, Item 1A. Risk Factors, Item 3. Legal Proceedings, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, and Item 7A. Quantitative Disclosures about Market Risk, includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended and Section 21E of the Securities Exchange Act of 1934, as amended. These statements typically contain words such as "anticipate," "believe," "estimate," "expect," "forecast," "plan," "predict," "target," "project," "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 that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

Forward-looking statements in this Annual Report on Form 10-K may include, but are not limited to, levels of revenues, income from operations, net income or earnings per share; levels of capital and exploration expenditures; the success or timing of completion of ongoing or anticipated capital; exploration projects; volumes of production or sales of natural gas, natural gas liquids, and crude oil; levels of worldwide prices of crude oil; levels of domestic natural gas prices; levels of natural gas liquids, natural gas and crude oil reserves; the acquisition or divestiture of assets; the potential effect of judicial proceedings on our business and financial condition; and the anticipated effects of actions of third parties such as competitors, or federal, state or local regulatory authorities.

While management believes that these forward-looking statements are reasonable as and when made, there can be no assurance that future developments affecting us will be those that we anticipate. All comments concerning our expectations for future revenues and operating results are based on our forecasts for our existing operations and do not include the potential impact of any future acquisitions, should we choose to make any. Our forward-looking statements involve significant risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and our present expectations or projections. For a description of known material factors that could cause our actual results to differ from those in the forward-looking statements, see "Item 1A. Risk Factors."

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

General

Range Resources Corporation, a Delaware corporation, is a Fort Worth, Texas-based independent natural gas, natural gas liquids ("NGLs") and oil company, engaged in the exploration, development and acquisition of natural gas and oil properties, mostly in the Appalachian and Midcontinent regions of the United States. Our corporate offices are located at 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102 (telephone (817) 870-2601). Our common stock is listed and traded on the New York Stock Exchange (the "NYSE") under the symbol "RRC." At December 31, 2014, we had 168.7 million shares outstanding.

Our 2014 production from operations consisted of the following:

- average total production of 1,162.4 Mmcfe per day, an increase of 24% from 2013;
- 68% natural gas;
- total natural gas production of 286.9 Bcf, an increase of 8% from 2013;
- total NGLs production of 18.8 Mmbbls (including ethane), an increase of 103% from 2013;
- total crude oil production of 4.1 Mmbbls, an increase of 6% from 2013; and
- 81% of our total production was from the Marcellus Shale in Pennsylvania.

At year-end 2014, our proved reserves had the following characteristics:

- 10.3 Tcfe of proved reserves;
- 67% natural gas;
- 52% proved developed;
- 96% operated;
- 86% of proved reserves are in the Marcellus Shale in Pennsylvania;
- a reserve life index of approximately 22 years (based on fourth quarter 2014 production);
- a pre-tax present value of $10.1 billion of future net cash flows, discounted at 10% per annum ("PV-10"[a]); and
- a standardized after-tax measure of discounted future net cash flows of $7.6 billion.

(a) PV-10 is considered a non-GAAP financial measure as defined by the SEC. We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure, or after-tax amount, because it presents the discounted future net cash flows attributable to our proved reserves before taking into account future corporate income taxes and our current tax structure. While the standardized measure is dependent on the unique tax situation of each company, PV-10 is based on prices and discount factors that are consistent for all companies. Because of this, PV-10 can be used within the industry and by creditors and security analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. The difference between the standardized measure and the PV-10 amount is discounted estimated future income tax of $2.5 billion at December 31, 2014.

Available Information

Our internet website is available at http://www.rangeresources.com. Information contained on or connected to our website is not incorporated by reference into this Form 10-K and should not be considered part of this report or any other filing we make with the U.S. Securities and Exchange Commission (the "SEC"). We make available, free of charge, on our website, the annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports, as soon as reasonably practicable after filing such reports with the SEC. Other information such as presentations, our Corporate Governance Guidelines, the charters of the Audit Committee, the Compensation Committee, the Dividend Committee, and the Governance and Nominating Committee, and the Code of Business Conduct and Ethics are available on our website and in print to any stockholder who provides a written request to the Corporate Secretary at 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102. Our Code of Business Conduct and Ethics applies to all directors, officers and employees, including the President and Chief Executive Officer and Chief Financial Officer.

The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers, including Range, that file electronically with the SEC. The public can obtain any document we file with the SEC at http://www.sec.gov.

Our Business Strategy

Our overarching business objective is to build stockholder value through consistent growth in reserves and production on a cost-efficient basis. Our strategy to achieve our business objective is to increase reserves and production through internally generated drilling projects coupled with occasional complementary acquisitions and occasional divestiture of non-core assets. Our strategy requires us to make significant investments and financial commitments in technical staff, acreage, seismic data, drilling and completion technology and gathering and transportation arrangements to build drilling inventory and market our products. Our strategy has the following key elements:

- commit to environmental protection and worker and community safety;
- concentrate in core operating areas;
- maintain a multi-year drilling inventory;
- focus on cost efficiency;
- maintain a long-life reserve base;
- market our products to a large number of customers in different markets under a variety of commercial terms;
- maintain operational and financial flexibility; and
- provide employee equity ownership and incentive compensation.

Commit to Environmental Protection and Worker and Community Safety. We strive to implement the latest technologies and best commercial practices to minimize adverse impacts from the development of our properties on the environment, worker health and safety and the safety of the communities where we operate. Working with peer companies, regulators, nongovernmental organizations, industries not related to the oil and natural gas industry and other engaged stakeholders, we consistently analyze and review performance while striving for continual improvement. We participate in FracFocus, a national publically accessible web-based registry to report, on a well-by-well basis, the additives and chemicals and amount of water used in the hydraulic fracturing process for each of the wells we operate. We encourage every employee to maintain safe operations, minimize environmental impact and conduct their daily business with the highest ethical standards.

Concentrate in Core Operating Areas. We currently operate in two regions: Appalachia (which includes Pennsylvania, Virginia, and West Virginia) and Midcontinent (which includes the Texas Panhandle, Oklahoma and Southern Kansas). Concentrating our drilling and producing activities in these core areas allows us to develop the regional expertise needed to interpret specific geological and operating conditions and develop economies of scale. Operating in core areas allows us to create a portfolio to assist in our goal of consistent production and reserve growth at attractive returns.

Maintain a Multi-Year Drilling Inventory. We focus on areas with multiple prospective and productive horizons and development opportunities. We use our technical expertise to build and maintain a multi-year drilling inventory. We believe that a large, multi-year inventory of drilling projects increases our ability to efficiently plan for the economic growth of production and reserves. Currently, we have over 10,000 proven and unproven drilling locations in inventory. Our goal is to grow year-over-year production by 20-25% by focusing on developing fields in our operating areas.

Focus on Cost Efficiency. We concentrate in core areas which we believe to have sizeable hydrocarbon deposits in place that will allow us to consistently increase production while controlling costs. As there is little long-term competitive sales price advantage available to a commodity producer, the costs to find, develop, and produce a commodity are important to organizational sustainability and long-term shareholder value creation. We endeavor to control costs such that our cost to find, develop and produce natural gas, NGLs and oil is one of the lowest in the industry. We operate almost all of our total net production and believe that our extensive knowledge of the geologic and operating conditions in the areas where we operate provides us with the ability to achieve operational efficiencies.

Maintain a Long-Life Reserve Base. Long-life natural gas and oil reserves provide a more stable growth platform than short-life reserves. Long-life reserves reduce reinvestment risk as they lessen the amount of reinvestment capital deployed each year to replace production. Long-life natural gas and oil reserves also assist us in minimizing costs as stable production makes it easier to build and maintain operating economies of scale. Long-life reserves also offer upside from technology enhancements. We use our drilling, divestiture and acquisition activities to assist in executing this strategy.

Market our products to a large number of customers in different markets under a variety of commercial terms. We market our natural gas, NGLs, and oil to a large number of customers in both domestic and international markets to maximize price and diversify risk. We hold considerable firm transportation contracts on multiple pipelines to enable us to transport and sell natural gas and NGLs in the Midwest, Gulf Coast, Southeast, Northeast and international markets. We sell our products under a variety of price indexes and price formulas that assist us in managing regional price differentials and commodity price volatility.

Maintain Operational and Financial Flexibility. Because of the risks involved in drilling, coupled with changing commodity prices, we are flexible and adjust our capital budget throughout the year. If certain areas generate higher than anticipated returns, we may accelerate development in those areas and decrease expenditures elsewhere. We also believe in maintaining a strong balance sheet, ample liquidity and using commodity derivatives to stabilize our realized prices. This provides more consistent cash flows and financial results.

Provide Employee Equity Ownership and Incentive Compensation. We want our employees to think and act like business owners. To achieve this, we reward and encourage them through equity ownership in Range. All full-time employees are eligible to receive equity grants. As of December 31, 2014, our employees owned equity securities in our benefit plans (vested and unvested) that had an aggregate market value of approximately $227.3 million. Our directors also have equity ownership in Range.

Significant Accomplishments in 2014

Production growth – In 2014, our production averaged 1,162.4 Mmcfe per day, an increase of 24% from 2013. Drilling in the Marcellus Shale play in Pennsylvania drove our production growth.

Reserve growth – Total proved reserves increased 26% in 2014 to 10.3 Tcfe, marking the thirteenth consecutive year our proved reserves have increased. This achievement is the result of continued drilling success, as the majority of our production and reserve growth in 2014 came from our drilling program. While consistent growth is challenging to sustain, we believe the quality of our technical teams and our substantial inventory of high quality drilling locations provide the basis for future reserve and production growth.

> Successful drilling program – In 2014, we drilled 255 gross natural gas and oil wells plus an additional 2 service wells. We replaced 565% of our production through drilling in 2014 and our overall drilling success rate was 99%. We continue to build our drilling inventory which is critical to our ability to drill a large number of wells each year on a cost effective and efficient basis. We drilled our first Utica/ Point Pleasant well located in Washington County, Pennsylvania, which achieved an average 24-hour test rate of 59.0 Mmcf per day during the initial flow back. We believe this well represents the highest initial production rate of any reported Utica well.

Large resource potential – Maintaining a large exposure to potential resources is important. We continued expansion of our unconventional resource shale plays in 2014. We have four large unconventional and prospective plays – the Marcellus, Utica/Point Pleasant and Upper Devonian shales in Pennsylvania and the Huron Shale in Virginia. These plays cover expansive areas, provide multi-year drilling opportunities and, collectively, have sustainable lower risk growth profiles. The economics of these plays have been enhanced by continued advancements in drilling and completion technologies. We have leased 1.4 million net acres in our four shale plays. We also have approximately 278,000 net acres in our coal bed methane plays in Virginia.

Continued development of processing, pipeline takeaway capacity and marketing of NGLs – We continue to ensure we have sufficient processing capacity and marketing agreements in place for our Pennsylvania production. In 2012, we entered into a fifteen year agreement (“Mariner East”) to transport ethane and propane from the tailgate of a third-party processing plant to a terminal and dock facility near Philadelphia. In the last few weeks of December 2014, line fill on the propane portion of this pipeline was completed with propane delivered to storage caverns to be sold at a later date. We expect both propane and ethane operations on Mariner East to be fully functional by the end of third quarter 2015. During 2014, we entered into additional firm transportation agreements to provide gas gathering and transportation from southwestern and northeastern Pennsylvania. At December 31, 2014, our agreements provide commitments that total 3.3 Bcfe per day.

Focus on financial flexibility – We ended the year with less debt than year-end 2013. Debt per mcfe of proved reserves was $0.30 at December 31, 2014 compared to $0.38 at December 31, 2013. In June 2014, we redeemed all $300.0 million aggregate principal amount of our 8.0% senior subordinated notes due 2019 with proceeds received of $397 million from a public offering of our common stock. As of December 31, 2014, we maintain a $4.0 billion bank credit facility, with a current borrowing base of $3.0 billion and our committed borrowing capacity on that date was $2.0 billion.

Land acquisitions completed – In 2014, we leased or renewed $226.5 million of acreage located in our core areas, primarily in the Marcellus Shale. We continue to see outstanding results in the Marcellus Shale. Production in the Marcellus Shale increased 32% while we continue to prove up acreage, acquire additional acreage and gain access to additional pipeline and processing capacity.

Acquisitions and dispositions completed – In June 2014, we sold our Conger assets in Glasscock and Sterling Counties, Texas in exchange for producing properties and other assets in Virginia and $145.0 million in cash, before closing adjustments (the “Conger Exchange”). We recognized a pre-tax gain of $282.7 million related to the Conger Exchange in the year ended December 31, 2014. We also received $28.8 million of additional proceeds during the year primarily related to the sale of miscellaneous proved and unproved properties.

Industry Operating Environment

We operate entirely within the continental United States. The oil and natural gas industry is affected by many factors that we cannot control. Government regulations, particularly in the areas of taxation, energy, climate change and the environment, can have a significant impact on operations and profitability. The impact of these factors is extremely difficult to accurately predict or anticipate. It is difficult for us to predict the occurrence of events that may affect commodity prices or the degree to which these prices will be affected; however, the prices we receive for the commodities we produce will generally approximate current market prices in the geographic region of the production.

Natural gas prices are generally determined by North American supply and demand. The New York Mercantile Exchange ("NYMEX") monthly settlement prices for natural gas averaged $4.37 per mcf in 2014, with a high of $5.56 per mcf in February and a low of $3.73 per mcf in November. Recently, natural gas prices have declined significantly, with the monthly settlement price for natural gas falling from $4.28 per mcf in December 2014 to $2.87 per mcf in February 2015. Natural gas prices continue to be under pressure due to concerns over excess supply of natural gas due to the high productivity of shale plays in the United States outpacing demand. Historically, the demand for drilling rigs, oilfield supplies and drill pipe is expected to decline with falling commodity prices but such declines tend to lag behind the declines in natural gas and crude oil prices.

Significant factors that will impact 2015 crude oil prices include worldwide economic conditions, political and economic developments in the Middle East, demand in Asian and European markets, and the extent to which members of the Organization of Petroleum Exporting Countries and other oil exporting nations choose to manage oil supply through export quotas. NYMEX monthly settlement prices for oil averaged $92.64 per barrel in 2014, with a high of $105.15 per barrel in June and a low of $59.29 per barrel in December. Recently, crude oil prices have declined significantly, with the monthly settlement price for crude oil falling from $75.81 per barrel in November 2014 to $47.33 per barrel in January 2015.

NGLs prices are generally determined by North American supply and demand. We expect NGLs prices in 2015 to continue to be under pressure due to concerns over excess supply.

Natural gas, NGLs and oil prices affect:

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

Natural gas and NGLs prices are likely to affect us more than oil prices because approximately 97% of our proved reserves is natural gas and NGLs. Any continued or extended decline in natural gas, NGLs and oil prices could have a material adverse effect on our financial position, results of operations, cash flows and access to capital. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we currently, and may in the future, use derivative instruments to hedge future sales prices on our natural gas, NGLs and oil production. The use of derivative instruments has in the past and may in the future, prevent us from realizing the full benefit of upward price movements but also partially protect us from declining price movements.

Segment and Geographical Information

Our operations consist of one reportable segment. We 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. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis. Our operations are limited to the United States and we focus on both unconventional resource plays and conventional plays in the Appalachian and Midcontinent regions of the United States.

Outlook for 2015

Our capital expenditure budget for 2015 has been set at approximately $870 million. As has been our historical practice, we will periodically review our capital expenditures throughout the year and may adjust the budget based on commodity prices, drilling success and markets for our products. At December 31, 2014, we have entered into hedging agreements covering 229.7 Bcfe for 2015. Since year-end 2014, we have entered into additional natural gas and NGLs hedges for 2015, 2016 and 2017. For a complete discussion of our hedging activities, a listing of open contracts at December 31, 2014 and the estimated fair value of these contracts as of that date, see Note 10 to our consolidated financial statements. Recently, natural gas and crude oil prices have dropped significantly. In response to the weakened natural gas and crude oil market, we lowered our capital expenditure budget that was announced in December 2014 from $1.3 billion to $870 million and we have announced a plan to close our Oklahoma City administrative and operations office by mid-2015 to reduce general and administrative expenses. These properties will be operated out of our Fort Worth offices. Our estimated 2015 capital expenditure budget detail and budget by area are shown below:

Production, Price and Cost History

The following table sets forth information regarding natural gas, NGLs and oil production, realized prices and production costs for the last three years. For more information, see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

	Year Ended December 31,		
	2014	2013	2012
Production			
Natural gas (Mmcf)	286,926	264,528	216,555
Natural gas liquids (Mbbls)	18,821	9,255	6,967
Crude oil and condensate (Mbbls)	4,070	3,827	2,851
Total (Mmcfe) [a]	424,267	343,022	275,465
Average sales prices (wellhead)			
Natural gas (per mcf)	$3.98	$3.61	$2.83
Natural gas liquids (per bbl)	23.60	34.07	38.05
Crude oil and condensate (per bbl)	77.80	86.00	83.46
Total (per mcfe) [a]	4.48	4.66	4.05
Average realized prices (including derivatives that qualify for hedge accounting):			
Natural gas (per mcf)	$3.99	$4.03	$3.93
Natural gas liquids (per bbl)	23.60	34.07	38.05
Crude oil and condensate (per bbl)	79.16	87.47	82.77
Total (per mcfe) [a]	4.51	5.00	4.91
Average realized prices (including all derivative settlements and third party transportation costs)			
Natural gas (per mcf)	$2.80	$3.08	$3.11
Natural gas liquids (per bbl)	22.04	31.29	41.03
Crude oil and condensate (per bbl)	79.75	84.70	83.64
Total (per mcfe) [a]	3.64	4.16	4.35
Direct operating costs			
Lease operating (per mcfe)	$0.31	$0.34	$0.39
Workovers (per mcfe)	0.03	0.02	0.02
Stock-based compensation (per mcfe)	0.01	0.01	0.01

Total (per mcfe)	$0.35	$0.37	$0.42

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

Proved Reserves

The following table sets forth our estimated proved reserves for year ended 2014, 2013 and 2012 based on the average of prices on the first day of each month of the given calendar year, in accordance with the SEC rules. Oil includes both crude oil and condensate. We have no natural gas, NGLs or oil reserves from non-traditional sources. Additionally, we do not provide optional disclosures of probable or possible reserves.

Summary of Oil and Gas Reserves as of Year-End Based on Average Prices

Reserve Category	Natural Gas (Mmcf)	NGLs (Mbbls)	Oil (Mbbls)	Total (Mmcfe) [a]	%
2014:					
Proved					
Developed	3,583,051	270,271	24,180	5,349,761	52 %
Undeveloped	3,339,785	245,636	24,478	4,960,468	48 %
Total Proved	6,922,836	515,907	48,658	10,310,229	100%
2013:					
Proved					
Developed	2,797,483	206,477	26,054	4,192,666	51 %
Undeveloped	2,868,162	167,935	22,306	4,009,608	49 %
Total Proved	5,665,645	374,412	48,360	8,202,274	100%
2012:					
Proved					
Developed	2,373,604	154,984	25,667	3,457,502	53 %
Undeveloped	2,419,072	85,415	19,415	3,048,068	47 %
Total Proved	4,792,676	240,399	45,082	6,505,570	100%

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

The following table sets forth summary information by area with respect to estimated proved reserves at December 31, 2014:

	Reserve Volumes					PV-10 [a]	
	Natural Gas (Mmcf)	NGLs (Mbbls)	Oil (Mbbls)	Total (Mmcfe)	%	Amount (In thousands)	%
Appalachian Region	6,681,073	495,586	40,006	9,894,625	96 %	$9,610,327	95 %
Midcontinent Region	241,763	20,321	8,652	415,604	4 %	459,947	5 %
Total	6,922,836	515,907	48,658	10,310,229	100%	$10,070,274	100%

[a] PV-10 was prepared using the twelve-month average prices for 2014, discounted at 10% per annum. Year-end PV-10 is a non-GAAP financial measure as defined by the SEC. We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure, or after tax amount, because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account future corporate income taxes and our current tax structure. While the standardized measure is dependent

on the unique tax situation of each company, PV-10 is based on prices and discount factors that are consistent for all companies. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. Our total standardized measure was $7.6 billion at December 31, 2014. The difference between the standardized measure and the PV-10 amount is the discounted estimated future income tax of $2.5 billion at December 31, 2014. Included in the $10.1 billion pre-tax PV-10 is $6.6 billion related to proved developed reserves.

Reserve Estimation

All reserve information in this report is based on estimates prepared by our petroleum engineering staff. We also have the following independent petroleum consultants conduct an audit of our year-end reserves: DeGolyer and MacNaughton (Midcontinent) and Wright and Company, Inc. (Appalachian). These engineers were selected for their geographic expertise and their historical experience in engineering certain properties. The proved reserve audits performed for 2014, 2013 and 2012, in the aggregate represented 96%, 96% and 93% of our proved reserves. The reserve audits performed for 2014, 2013 and 2012, in the aggregate represented 98%, 97% and 88% of our 2014, 2013 and 2012 associated pre-tax present value of proved reserves discounted at ten percent. Copies of the summary reserve reports prepared by each of these independent petroleum consultants are included as an exhibit to this Annual Report on Form 10-K. The technical person at each independent petroleum consulting firm responsible for reviewing the reserve estimates presented herein meets the requirements regarding qualifications, independence, objectivity and confidentiality as set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent petroleum consultants to ensure the integrity, accuracy and timeliness of data furnished during the reserve audit process. Throughout the year, our technical team meets periodically with representatives of each of our independent petroleum consultants to review properties and discuss methods and assumptions. While we have no formal committee specifically designated to review reserves reporting and the reserve estimation process, our senior management reviews and approves significant changes to our proved reserves. We provide historical information to our consultants for our largest producing properties such as ownership interest, natural gas, NGLs and oil production, well test data, commodity prices and operating and development costs. The consultants perform an independent analysis and differences are reviewed with our Senior Vice President of Reservoir Engineering and Economics. In some cases, additional meetings are held to review identified reserve differences. The reserve auditor estimates of proved reserves and the pre-tax present value of such reserves discounted at 10% did not differ from our estimates by more than 10% in the aggregate. However, when compared on a lease-by-lease, field-by-field or area-by-area basis, some of our estimates may be greater than those of the auditors and some may be less than the estimates of the reserve auditors. When such differences do not exceed 10% in the aggregate, our reserve auditors are satisfied that the proved reserves and pre-tax present value of such reserves discounted at 10% are reasonable and will issue an unqualified opinion. Remaining differences are not resolved due to the limited cost benefit of continuing such analysis.

Historical variances between our reserve estimates and the aggregate estimates of our independent petroleum consultants have been less than 5%. All of our reserve estimates are reviewed and approved by our Senior Vice President of Reservoir Engineering and Economics, who reports directly to our Chairman, President and Chief Executive Officer. Our Senior Vice President of Reservoir Engineering and Economics holds a Bachelor of Science degree in Electrical Engineering from the Pennsylvania State University. Before joining Range, he held various technical and managerial positions with Amoco, Hunt Oil and Union Pacific Resources and has more than thirty-five years of engineering experience in the oil and gas industry. During the year, our reserves group may also perform separate, detailed technical reviews of reserve estimates for significant acquisitions or for properties with problematic indicators such as excessively long lives, sudden changes in performance or changes in economic or operating conditions. We did not file any reports during the year ended December 31, 2014 with any federal authority or agency with respect to our estimate of natural gas and oil reserves.

Reserve Technologies

Proved reserves are those quantities of natural gas, natural gas liquids and oil, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term “reasonable certainty” implies a high degree of confidence that the quantities of natural gas, NGLs and oil actually recovered will equal or exceed the estimate. To achieve reasonable certainty, our internal technical staff employs technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, empirical evidence through drilling results and well performance, well logs, geologic maps and available downhole and production data, seismic data, well test data and reservoir simulation modeling.

Reporting of Natural Gas Liquids

We produce natural gas liquids, or NGLs, as part of the processing of our natural gas. The extraction of NGLs in the processing of natural gas reduces the volume of natural gas available for sale. At December 31, 2014, NGLs represented approximately 30% of our total proved reserves on an mcf equivalent basis. NGLs are products priced by the gallon (and sold by the barrel) to the end-user. In reporting proved reserves and production of NGLs, we have included production and reserves in barrels. Prices for a barrel of NGLs in 2014 averaged approximately 70% lower than the average prices for equivalent volumes of oil. We report all production information related to natural gas net of the effect of any reduction in natural gas volumes resulting from the processing of NGLs. As of December 31, 2014, we have 1,170 Bcfe of ethane reserves (264.3 Mmbbls) associated with our Marcellus Shale, which are included in NGLs proved reserves.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2014, our PUDs totaled 24.5 Mmbbls of crude oil, 245.6 Mmbbls of NGLs and 3.3 Tcfe of natural gas, for a total of 5.0 Tcfe. Costs incurred in 2014 relating to the development of PUDs were approximately $591.0 million. Approximately 93% of our PUDs at year-end 2014 were associated with the Marcellus Shale. All PUD drilling locations are scheduled to be drilled prior to the end of 2019 with more than 80% of the future development costs expected to be spent in the next three years. Changes in PUDs that occurred during the year were due to:

- conversion of approximately 620 Bcfe of PUDs into proved developed reserves;

new PUDs added consisting of 1,776 Bcfe;
147 Bcfe negative revision with 611 Bcfe of reserves reclassified to unproved because of a slower pace of development activity beyond the five-year development horizon as we continue to see success from drilling longer laterals, increasing the number of frac stages and better lateral targeting partially offset by improved recovery of 450 Bcfe and other performance revisions; and
58 Bcfe reduction from the sale of properties.

Proved Reserves (PV-10)

The following table sets forth the estimated future net cash flows, excluding open derivative contracts, from proved reserves, the present value of those net cash flows discounted at a rate of 10% (PV-10), and the expected benchmark prices and average field prices used in projecting net cash flows over the past five years. Our reserve estimates do not include any probable or possible reserves (in millions, except prices):

	2014	2013	2012	2011	2010
Future net cash flows	$26,993	$21,029	$11,156	$15,610	$12,516
Present value:					
Before income tax	10,070	7,898	3,960	6,084	4,647
After income tax (Standardized Measure)	7,593	5,862	3,224	4,515	3,479
Benchmark prices (NYMEX):					
Gas price (per mcf)	4.35	3.67	2.76	4.12	4.38
Oil price (per bbl)	94.42	97.33	95.05	95.61	79.81
Wellhead prices:					
Gas price (per mcf)	4.14	3.75	2.75	3.55	3.70
Oil price (per bbl)	79.04	86.66	86.91	85.59	72.51
NGLs price (per bbl)	27.20	25.93	32.23	49.24	39.14

Future net cash flows represent projected revenues from the sale of proved reserves net of production and development costs (including operating expenses and production taxes) and revenues are based on a twelve-month unweighted average of the first day of the month pricing, without escalation. Future cash flows are reduced by estimated production costs, administrative costs, costs to develop and produce the proved reserves and abandonment costs, all based on current economic conditions at each year-end. There can be no assurance that the proved reserves will be produced in the future or that prices, production or development costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties.

Property Overview

Our natural gas and oil operations are concentrated in the Appalachian and Midcontinent regions of the United States. Our properties consist of interests in developed and undeveloped natural gas and oil leases in these regions. These interests entitle us to drill for and produce natural gas, NGLs, crude oil and condensate from specific areas. Our interests are mostly in the form of working interests and, to a lesser extent, royalty and overriding royalty interests. We have a single company-wide management team that administers all properties as a whole. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis.

The table below summarizes data for our operating regions for the year ended December 31, 2014.

Region	Average Daily Production	Production (Mmcfe)	Percentage of Production	Proved Reserves (Mmcfe)	Percentage of Proved Reserves

	(mcfe per day)						
Appalachian	1,059,318	386,651	91	%	9,894,625	96	%
Midcontinent	103,056	37,616	9	%	415,604	4	%
Total	1,162,374	424,267	100	%	10,310,229	100	%

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The following table summarizes our costs incurred by operating region for the year ended December 31, 2014 (in thousands):

	Acquisitions (a)	Acreage Purchases	Development Costs	Exploration Costs	Gathering Facilities	Asset Retirement Obligations	Total
Appalachian	$ 404,252	$ 207,838	$ 1,026,968	$ 221,112	$ 12,035	$ 53,383	$ 1,925,588
Midcontinent	¾	18,637	92,928	23,361	1,102	3,439	139,467
Total costs incurred	$ 404,252	$ 226,475	$ 1,119,896	$ 244,473	$ 13,137	$ 56,822	$ 2,065,055

(a) Includes $11.9 million of asset retirement obligations and $134.8 million of gas gathering assets.

Approximately 86% of our proved reserves at December 31, 2014 are located in the Marcellus Shale in our Appalachian region. This play has a large portfolio of drilling opportunities. The following table below sets forth annual production volumes, average sales prices and production cost data for our wells in the Marcellus Shale which, as of December 31, 2014, is our only field in which reserves are greater than 15% of our total proved reserves.

Marcellus Shale Field	2014	2013	2012
Production:			
Natural gas (Mmcf)	224,034	203,926	149,589
NGLs (Mbbls)	17,093	7,213	5,034
Crude oil and condensate (Mbbls)	3,089	2,529	1,564
Total Mmcfe (a)	345,127	262,377	189,178
Sales Prices: (b)			
Natural gas (per mcf)	$ 2.72	$ 2.59	$ 1.86
NGLs (per bbl)	20.32	33.19	38.48
Crude oil and condensate (per bbl)	73.77	82.11	78.56
Total (per mcfe)	3.43	3.72	3.14
Production Costs:			
Lease operating (per mcfe)	$0.19	$0.16	$0.18
Production and ad valorem tax (per mcfe) (c)	0.08	0.11	0.26

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

(b) We do not record derivatives or the results of derivatives at the field level. Includes deductions for third party transportation, gathering and compression expense.

(c) Includes Pennsylvania impact fee.

Appalachian Region

Our properties in this area are located in the Appalachian Basin in the northeastern United States, principally in Pennsylvania, Virginia and West Virginia. The reserves from the Marcellus Shale, the Pennsylvanian (coalbed formation), Berea, Big Lime, Huron Shale, Medina and Upper Devonian formations principally produce at depths ranging from 2,500 feet to 9,000 feet. We own 7,582 net producing wells, 96% of which we operate. Our average working interest in this region is 90%. As of December 31, 2014, we have approximately 1.6 million gross (1.4 million net) acres under lease, which includes 305,000 acres in which we also own a royalty interest.

Reserves at December 31, 2014 were 9.9 Tcfe, an increase of 2.4 Tcfe, or 31%, from 2013. Drilling additions (2.3 Tcfe), purchases (262.8 Bcfe), favorable reserve revisions for performance and price and improved recovery were partially offset by production and downward revisions for proved undeveloped reserves no longer in our current five year development plan (581.5 Bcfe). Annual production increased 30% from 2013. During 2014, we spent $1.2 billion in this region to drill 201 (190.5 net) development wells and 25 (21.4 net) exploratory wells, of which all were productive. At December 31, 2014, the Appalachian region had an inventory of over 800 proven drilling locations and over 600 proven recompletions. During the year, the Appalachian region drilled 105 proven locations, added 163 new proven drilling locations and deleted 116 proven drilling locations with reserves reclassified to unproved because of a slower pace of development activity beyond the five-year development horizon as required by the SEC's reserve reporting requirements. During the year, the region achieved a 100% drilling success rate.

Marcellus Shale

We began operations in the Marcellus Shale in Pennsylvania during 2004. The Marcellus Shale is an unconventional reservoir, which produces natural gas, NGLs and condensate. This has been our largest investment area over the last six years. We had over 500 proven drilling locations at December 31, 2014. Our 2014 production from the Marcellus Shale increased 32% from 2013. During 2014, we drilled 149 (139.5 net) development wells and 25 (21.4 net) exploratory wells, all of which were successful. In 2015, we plan to drill over 130 net wells. During 2014, we had approximately 9 drilling rigs in the field and expect to run an average of 7 rigs throughout 2015.

We have long-term agreements with third parties to provide gathering and processing services and infrastructure assets in the Marcellus Shale, which includes gathering and residue gas pipelines, compression, cryogenic processing, de-ethanization and liquid fractionation. In 2011, we executed an ethane sales contract for the liquids-rich gas in southwestern Pennsylvania whereby a third party will transport ethane from the tailgate of the third-party processing and fractionation facilities to the international border for further delivery into Canada. Initial deliveries commenced in second half 2013. Also in 2011, we entered into an agreement to transport ethane to the Gulf Coast where initial deliveries also commenced in late 2013.

In 2012, we entered into a fifteen year agreement to transport ethane and propane from the tailgate of a third-party processing plant to a terminal and dock facility near Philadelphia. Line fill on the propane portion of this pipeline was completed in late December 2014, with propane delivered to storage caverns to be sold at a later date. We expect both propane and ethane operations to be fully functional by the end of third quarter 2015. In the meantime, since 2012, we have been transporting a portion of our propane by rail and truck to the terminal and dock facility near Philadelphia for sale to domestic and international customers. Also in 2012, we executed a fifteen year ethane sales agreement from the same terminal near Philadelphia which is expected to begin in third quarter 2015.

Since 2008, we have entered into various firm transportation agreements to provide gas gathering and transportation from southwestern and northeastern Pennsylvania which, at December 31, 2014 provide commitments for 3.3 Bcfe per day. Some of our agreements, which extend to 2030, are contingent on pipeline modifications and/or construction. To support our drilling efforts and to control costs, we have agreements for hydraulic fracturing services, including related equipment, material and labor, in Pennsylvania through 2015.

Midcontinent Region

The Midcontinent region includes drilling, production and field operations in the Texas Panhandle, as well as in the Anadarko Basin of western Oklahoma, the Nemaha Uplift of northern Oklahoma and Kansas, the Permian Basin of West Texas and Mississippi. In the Midcontinent region, we own 653 net producing wells, 95% of which we operate. Our average working interest is 78%. As of December 31, 2014, we have approximately 507,000 gross (383,000 net) acres under lease.

Total proved reserves in the Midcontinent region decreased 247.5 Bcfe, or 37%, at December 31, 2014, when compared to year-end 2013. Drilling additions (80.4 Bcfe) and positive pricing revisions were offset by production, property sales (220.1 Bcfe) and negative performance revisions. Annual production volumes decreased 18% from 2013. During 2014, this region spent $116.3 million to drill 28 (26.2 net) development wells and one (one net) exploratory well, of which 27 (25.2 net) were productive. During the year, the region achieved a 93% drilling success rate. The region also drilled 2 service wells in 2014.

At December 31, 2014, the Midcontinent region had a development inventory of over 80 proven drilling locations and over 220 proven recompletions. During the year, the Midcontinent region drilled 6 proven locations, added 26 new proven locations and deleted 69 proven drilling locations primarily due to the sale of properties. Development projects include recompletions and infill drilling. These activities also include increasing reserves and production through cost control, upgrading lifting equipment, improving gathering systems and surface facilities, and performing restimulations and refracturing operations.

Producing Wells

The following table sets forth information relating to productive wells at December 31, 2014. If we own both a royalty and a working interest in a well, such interest is included in the table below. Wells are classified as natural gas or crude oil according to their predominant production stream. We do not have a significant number of dual completions.

	Total Wells		Average Working
	Gross	Net	Interest
Natural gas	9,125	8,113	89 %
Crude oil	132	122	93 %
Total	9,257	8,235	89 %

The day-to-day operations of natural gas and oil properties are the responsibility of the operator designated under pooling or operating agreements. The operator supervises production, maintains production records, employs or contracts for field personnel and performs other functions. An operator receives reimbursement for direct expenses incurred in the performance of its duties as well as monthly per-well producing and drilling overhead reimbursement at rates customarily charged by unaffiliated third parties. The charges customarily vary with the depth and location of the well being operated.

Drilling Activity

The following table summarizes drilling activity for the past three years. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells. As of December 31, 2014, we were in the process of drilling 49.0 (48.1 net) wells. In 2014, we also drilled 2 (2 net) service wells.

	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Productive	228.0	215.7	178.0	171.9	226.0	202.3
Dry	1.0	1.0	1.0	1.0	¾	¾
Exploratory wells						
Productive	25.0	21.4	39.0	35.5	72.0	54.5
Dry	1.0	1.0	1.0	0.2	¾	¾
Total wells						
Productive	253.0	237.1	217.0	207.4	298.0	256.8
Dry	2.0	2.0	2.0	1.2	¾	¾
Total	255.0	239.1	219.0	208.6	298.0	256.8
Success ratio	99.2 %	99.2 %	99.1 %	99.4 %	100 %	100 %

Gross and Net Acreage

We own interests in developed and undeveloped natural gas and oil acreage. These ownership interests generally take the form of working interests in oil and natural gas leases that have varying terms. Developed acreage includes leased acreage that is allocated or assignable to producing wells or wells capable of production even though shallower or deeper horizons may not have been fully explored. Undeveloped acreage includes leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas or oil, regardless of whether or not the acreage contains proved reserves.

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own a working interest as of December 31, 2014. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Illinois	¾	¾	13,332	7,312	13,332	7,312
Kansas	¾	¾	28,604	28,419	28,604	28,419
Louisiana	571	226	¾	¾	571	226
Mississippi	5,373	3,264	904	623	6,277	3,887

New York	¾	¾	3,067	968	3,067	968
Ohio	40	40	¾	¾	40	40
Oklahoma	152,205	126,340	231,505	163,841	383,710	290,181
Pennsylvania	556,559	514,893	467,347	403,915	1,023,906	918,808
Texas	37,301	29,885	37,403	26,287	74,704	56,172
Virginia	122,719	120,924	238,185	238,185	360,904	359,109
West Virginia	51,792	50,229	51,068	50,330	102,860	100,559
Wyoming	¾	¾	9,565	9,565	9,565	9,565
	926,560	845,801	1,080,980	929,445	2,007,540	1,775,246
Average working interest		91 %		86 %		88 %

Undeveloped Acreage Expirations

The table below summarizes by year our undeveloped acreage scheduled to expire in the next five years.

As of December 31,	Acres Gross	Net	% of Total Undeveloped
2015	104,886	90,266	10%
2016	120,028	111,578	12%
2017	150,215	107,712	12%
2018	52,778	40,972	4%
2019	36,599	32,062	3%

In all cases the drilling of a commercial well will hold acreage beyond the expiration date. We have leased acreage that is subject to lease expiration if initial wells are not drilled within a specified period, generally between three to five years. However, we have in the past and expect in the future, to be able to extend the lease terms of some of these leases and sell or exchange some of these leases with other companies. The expirations included in the table above do not take into account the fact that we may be able to extend the lease terms. We do not expect to lose significant lease acreage because of failure to drill due to inadequate capital, equipment or personnel. However, based on our evaluation of prospective economics, we have allowed acreage to expire from time to time and expect to allow additional acreage to expire in the future.

Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, in the case of undeveloped properties, often minimal investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. Burdens on properties may include:

- customary royalty interests;
- liens incident to operating agreements and for current taxes;
- obligations or duties under applicable laws;
- development obligations under oil and gas leases; or
- net profit interests.

Delivery Commitments

For a discussion of our delivery commitments, see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations-Delivery Commitments.”

Employees

As of January 1, 2015, we had 990 full-time employees, 401 of whom were field personnel. In first quarter 2015, we announced we will close our Oklahoma City administrative and operations office which will impact approximately 100 employees. All full-time employees are eligible to receive equity awards approved by the Compensation Committee of the Board of Directors. No employees are currently covered by a labor union or other collective bargaining arrangement. We believe that the relationship with our employees is excellent. We regularly use independent consultants and contractors to perform various professional services, particularly in the areas of drilling, completion, field services, on-site production services and certain accounting functions.

Competition

Intense competition exists in all sectors of the oil and gas industry and in particular, we encounter substantial competition in developing and acquiring natural gas and oil properties, securing and retaining personnel, conducting drilling and field operations and marketing production. Competitors in exploration, development, acquisitions and production include the major oil and gas companies as well as numerous independent oil and gas companies, individual proprietors and others. Although our sizable acreage position and core area concentration provide some competitive advantages, many competitors have financial and other resources substantially exceeding ours. Therefore, competitors may be able to pay more for desirable leases and evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources allow. Our ability to replace and expand our reserve base depends on our ability to attract and retain quality personnel and identify and acquire suitable producing properties and prospects for future drilling. For more information, see “Item 1A. Risk Factors.”

Marketing and Customers

We market the majority of our natural gas, NGLs, crude oil and condensate production from the properties we operate for our interest, and that of the other working interest owners. We pay our royalty owners from the sales attributable to our working interest. Natural gas, NGLs and oil purchasers are selected on the basis of price, credit quality and service reliability. For a summary of purchasers of our natural gas, NGLs and oil production that accounted for 10% or more of consolidated revenue, see Note 2 to our consolidated financial statements. Because alternative purchasers of natural gas and oil are usually readily available, we believe that the loss of any of these purchasers would not have a material adverse effect on our operations. Production from our properties is marketed using methods that are consistent with industry practice. Sales prices for natural gas, NGLs and oil production are negotiated based on factors normally considered in the industry, such as index or spot price, distance from the well to the pipeline, commodity quality and prevailing supply and demand conditions. Our natural gas production is sold to utilities, marketing and mid-stream companies and industrial users. Our NGLs production is typically sold to natural gas processors or users of NGLs. Our oil and condensate production is sold to crude oil processors, transporters and refining and marketing companies in the area. Market volatility due to fluctuating weather conditions, international political developments, overall energy supply and demand, economic growth rates and other factors in the United States and worldwide have had, and will continue to have, a significant effect on energy prices.

We enter into derivative transactions with unaffiliated third parties for a varying portion of our production to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in natural gas, NGLs and oil prices. For a more detailed discussion, see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Item 7A. Quantitative and Qualitative Disclosures about Market Risk.”

We incur gathering and transportation expense to move our production from the wellhead and tanks to purchaser specified delivery points. These expenses vary based on volume, distance shipped and the fee charged by the third-party gatherers and transporters. In the Midcontinent region, our production is transported primarily through purchaser-owned or third-party trucks, field gathering systems and transmission pipelines. Transportation capacity on these gathering and transportation systems and pipelines is occasionally constrained. In Appalachia, we own some gas gathering pipelines, which transport a portion of our Appalachian production and third-party production to transmission lines, directly to end-users and interstate pipelines. Our remaining Appalachian production is transported on third-party pipelines on which, in most cases, we hold long-term contractual capacity. We attempt to balance sales, storage and transportation positions, which can include purchase of commodities from third parties for resale, to satisfy transportation commitments.

We have not experienced significant difficulty to date in finding a market for all of our production as it becomes available or in transporting our production to those markets; however, there is no assurance that we will always be able to transport and market all of our production or obtain favorable prices.

We have entered into three ethane agreements to sell or transport ethane from our Marcellus Shale area. Initial deliveries commenced in late 2013 on two of these agreements. The remaining agreement is contingent on pipeline modifications and/or construction with operations expected to begin in mid-2015. For more information, see “Item 1A. Risk Factors – Our business depends on natural gas and oil transportation and NGLs processing facilities, most of which are owned by others and depends on our ability to contract with those parties.”

Seasonal Nature of Business

Generally, but not always, the demand for natural gas and propane decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or hot summers sometimes accentuate this fluctuation. In addition, pipelines, utilities, local distribution companies and industrial end-users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also impact the seasonality of demand.

Governmental Regulation

Enterprises that sell securities in public markets are subject to regulatory oversight by federal agencies such as the SEC and the NYSE, a private stock exchange which requires us to comply with listing requirements for our common stock listed. This regulatory oversight imposes on us the responsibility for establishing and maintaining disclosure controls and procedures and internal controls over financial reporting, and ensuring that the financial statements and other information included in submissions to the SEC do not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made in such submissions not misleading. Failure to comply with the NYSE listing rules and regulations of the SEC could subject us to litigation from public or private plaintiffs. Failure to comply with the rules of the NYSE could result in the de-listing of our common stock, which could have an adverse effect on the market price of our common stock. Compliance with some of these rules and regulations is costly, and regulations are subject to change or reinterpretation.

Exploration and development and the production and sale of oil and gas are subject to extensive federal, state and local regulations. An overview of these regulations is set forth below. We believe we are in substantial compliance with currently applicable laws and regulations and the continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. See "Item 1A. Risk Factors – The natural gas and oil industry is subject to extensive regulation." We do not believe we are affected differently by these regulations than others in the industry.

General Overview. Our oil and gas operations are subject to various federal, state, tribal and local laws and regulations. Generally speaking, these regulations relate to matters that include, but are not limited to:

- leases;
- acquisition of seismic data;
- location of wells, pads, roads, impoundments, facilities, rights of way;
- size of drilling and spacing units or proration units;
- number of wells that may be drilled in a unit;
- unitization or pooling of oil and gas properties;
- drilling, casing and completion of wells;
- issuance of permits in connection with exploration, drilling and production;
- well production, maintenance, operations and security;
- spill prevention and containment plans;
- emissions permitting or limitations;
- protection of endangered species;
- use, transportation, storage and disposal of fluids and materials incidental to oil and gas operations;
- surface usage and the restoration of properties upon which wells have been drilled;
- calculation and disbursement of royalty payments and production taxes;
- plugging and abandoning of wells;
- transportation of production; and
- health and safety of employees and contract service providers.

In August 2005, Congress enacted the Energy Policy Act of 2005 ("EPAct 2005"). Among other matters, EPAct 2005 amends the Natural Gas Act ("NGA") to make it unlawful for "any entity," including otherwise non-jurisdictional producers such as Range, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the Federal Energy Regulatory Commission (the "FERC"), in contravention of rules prescribed by the FERC. On January 20, 2006, the FERC issued rules implementing this provision. The rules make it unlawful in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit any such statement necessary to make the statements not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the NGA of up to $1,000,000 per day per violation. The anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities or otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to the FERC's jurisdiction which includes the reporting requirements under Order 704, defined and described below. It therefore reflects a significant expansion of the FERC's enforcement authority. Range has not been affected differently than any other producer of natural gas by this act. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the FERC, and the courts. We cannot predict when or whether any such proposals may become effective.

On December 26, 2007, the FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing (“Order 704”). Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtus of physical natural gas in the previous calendar year, including natural gas gatherers and marketers, are now required to report to the FERC, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with the FERC’s policy statement on price reporting. On November 15, 2012, Docket No. RM13-1, the FERC issued a Notice of Inquiry seeking comments on whether it should require all market participants engaged in sales of wholesale physical natural gas in interstate commerce to report quarterly to the FERC every natural gas transaction within the FERC’s NGA jurisdiction that entails physical delivery for the next day or for the next month in order to improve natural gas market transparency. We cannot predict when or whether any such proposals may become effective.

Environmental and Occupational Health and Safety Matters

Our operations are subject to numerous stringent federal, state and local laws and regulations governing occupational health and safety, the discharge of materials into the environment or otherwise relating to environmental protection, some of which carry substantial administrative, civil and criminal penalties for failure to comply. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines, govern the sourcing and disposal of water used in the drilling and completion process, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, frontier and other protected areas, require some form of remedial action to prevent or mitigate pollution from existing and former operations such as plugging abandoned wells or closing earthen impoundments and impose substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings. These laws and regulations also may restrict the rate of production. Moreover, changes in environmental laws and regulations often occur, and any changes that result in more stringent and costly well construction, drilling, water management or completion activities or more restrictive waste handling storage, transport, disposal or cleanup requirements for any substances used or produced in our operations could materially adversely affect our operations and financial position, as well as those of the oil and natural gas industry in general.

The Comprehensive Environmental Response, Compensation and Liability Act, as amended (“CERCLA”), also known as the “Superfund” law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a “hazardous substance” into the environment. These persons may include owners or operators of the disposal site or sites where the hazardous substance release occurred and companies that disposed of or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, all of these persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties, pursuant to environmental statutes, common law or both, to file claims for personal injury and property damages allegedly caused by the release of hazardous substances or other pollutants into the environment. Although petroleum, including crude oil and natural gas, is not a “hazardous substance” under CERCLA, at least two courts have ruled that certain wastes associated with the production of crude oil may be classified as “hazardous substances” under CERCLA and that releases of such wastes may therefore give rise to liability under CERCLA. While we generate materials in the course of our operations that may be regulated as hazardous substances, we have not received notification that we may be potentially responsible for cleanup costs under CERCLA or comparable state laws. Other state laws regulate the disposal of oil and natural gas wastes, and new state and federal regulatory initiatives that could have a significant adverse impact on us may periodically be proposed and enacted.

We also may incur liability under the Resource Conservation and Recovery Act, as amended (“RCRA”) and comparable state laws, which impose requirements related to the handling and disposal of non-hazardous solid wastes and hazardous wastes. Drilling fluids, produced waters, and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy are currently regulated by the United States Environmental Protection Agency (“EPA”) and state agencies under RCRA’s less stringent non-hazardous solid waste provisions. It is possible that these solid wastes could in the future be reclassified as hazardous wastes, whether by amendment of RCRA or adoption of new laws, which could significantly increase our costs to manage and dispose of such wastes. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils, may be regulated as hazardous wastes. Although the costs of managing wastes classified as hazardous waste may be significant, we do not expect to experience more burdensome costs than similarly situated companies in our industry.

We currently own or lease, and have in the past owned or leased, properties that for many years have been used for the exploration and production of crude oil and natural gas. Petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us, or on or under other locations where such materials have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons and wastes was not under our control. These properties and the materials disposed or released on them may be subject to

CERCLA, RCRA and comparable state laws and regulations. Under such laws and regulations, we could be required to remove or remediate previously disposed wastes or property contamination, or to perform remedial activities to prevent future contamination.

The Federal Water Pollution Control Act, as amended (the “CWA”), and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. These laws also prohibit the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages. Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as “SPCC plans,” in connection with on-site storage of greater than threshold quantities of oil. We regularly review our natural gas and oil properties to determine the need for new or updated SPCC plans and, where necessary, we will be developing or upgrading such plans, the costs of which are not expected to be substantial.

The Oil Pollution Act of 1990, as amended (“OPA”), contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from an oil spill, including, but not limited to, the costs of responding to a release of oil to surface waters. While we believe we have been in substantial compliance with OPA, noncompliance could result in varying civil and criminal penalties and liabilities.

The Clean Air Act, as amended, and comparable state laws restrict the emission of air pollutants from many sources, including compressor stations. These laws and any implementing regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, impose stringent air permit requirements, or use specific equipment or technologies to control emissions. We may be required to incur certain capital expenditures in the next few years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals for emissions of pollutants. For example, on January 14, 2015, the Obama Administration announced that the EPA is expected to propose in the summer of 2015 and finalize in 2016 new regulations that will set methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities as part of the Administration’s efforts to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025. In a second example, in December 2014, the EPA published a proposed rulemaking that it expects to finalize by October 1, 2015, which rulemaking proposes to revise the National Ambient Air Quality Standard for ozone between 65 to 70 parts per billion for both the 8-hour primary and secondary standards. Compliance with one or both of these regulatory initiative could directly impact us by requiring installation of new emission controls on some of our equipment, resulting in longer permitting timelines, and significantly increasing our capital expenditures and operating costs, which could adversely impact our business.

In 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases (“GHGs”) present a danger to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth’s atmosphere and other climatic conditions. Based on these findings, the EPA adopted regulations under the existing Clean Air Act establishing Title V and Prevention of Significant Deterioration (“PSD”) permitting reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. We could become subject to these Title V and PSD permitting reviews and be required to install “best available control technology” to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future if such facilities emitted volumes of GHGs in excess of threshold permitting levels. The EPA has also adopted rules requiring the reporting of

GHG emissions from specified emission sources in the United States on an annual basis, including certain oil and natural gas production facilities, which include several of our facilities. We are monitoring several of our operations for GHG emissions and believe that our monitoring activities are in substantial compliance with applicable reporting obligations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of federal climate legislation in the U.S., a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emission allowances or comply with new regulatory or reporting requirements. For example, pursuant to President Obama’s Strategy to Reduce Methane Emissions, the Obama Administration announced on January 14, 2015 that the EPA is expected to propose in the summer of 2015, and finalize in 2016, new regulations that will set methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities as part of the Administration's efforts to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for oil and natural gas, which could reduce the demand for the oil and natural gas that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

Hydraulic fracturing, which has been used by the industry for over 60 years, is an important and common practice used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely apply hydraulic fracturing techniques as part of our operations. This process is typically regulated by state oil and natural gas commissions; however, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final Clean Air Act regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; announced its intent to propose in early 2015 effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, in May 2013, the federal Bureau of Land Management ("BLM") issued a revised proposed rule containing disclosure requirements and other mandates for hydraulic fracturing on federal lands and the agency is now analyzing comments to the proposed rulemaking and is expected to promulgate a final rule in early 2015. Moreover, from time to time, Congress has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. In addition to any actions by Congress, certain states in which we operate, including Pennsylvania, Texas and West Virginia have adopted, and other states are considering adopting, regulations imposing or that could impose new or more stringent permitting, public disclosure, or well construction requirements on hydraulic fracturing operations. States could also elect to prohibit hydraulic fracturing altogether. In December 2014, Governor Cuomo of the State of New York announced fracturing activities in New York would be prohibited. Local governments also may seek to adopt ordinances within their jurisdiction regulating the time, place or manner of drilling activities in general or hydraulic fracturing activities in particular. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process is adopted in areas where we currently or in the future plan to operate, we may incur additional, more significant, costs to comply with such requirements and also could become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development, or production activities.

In addition, certain government reviews are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a final draft report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review in early 2015. These existing or any future studies, depending on any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Act or other regulatory mechanisms.

We believe that our hydraulic fracturing activities follow applicable industry practices and legal requirements for groundwater protection and that our fracturing operations have not resulted in material environmental liabilities. We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our existing insurance policies would cover third-party bodily injury and property damage caused by hydraulic fracturing including sudden and accidental pollution coverage.

Oil and natural gas exploration, development and production activities on federal lands, including Indian lands and lands administered by the BLM, are subject to the National Environmental Policy Act, as amended (“NEPA”). NEPA requires federal agencies, including the BLM, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. Currently, we have minimal exploration and production activities on federal lands. However, for those current activities as well as for future or proposed exploration and development plans on federal lands, governmental permits or authorizations that are subject to the requirements of NEPA are required. This process has the potential to delay or limit, or increase the cost of, the development of oil and natural gas projects. Authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt projects.

The federal Endangered Species Act, as amended (the “ESA”), restricts activities that may affect endangered and threatened species or their habitats. If endangered species are located in an area where we wish to conduct seismic surveys, development activities or abandonment operations, the work could be prohibited or delayed or expensive mitigation may be required. Moreover, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas. As a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service ("FWS") is required to make a determination on the listing of numerous species as endangered or threatened under the Endangered Species Act prior to the completion of the agency's 2017 fiscal year. For example, in March 2014, the FWS announced the listing of the lesser prairie chicken, whose habitat is over a five-state region, including Oklahoma, where we conduct operations, as a threatened species under the ESA. However, the FWS also announced a final rule that will limit regulatory impacts on landowners and businesses from the listing if those landowners and businesses have entered into certain range-wide conservation planning agreements, such as those developed by the Western Association of Fish and Wildlife Agencies, pursuant to which such parties agreed to take steps to protect the lesser prairie chicken's habitat and to pay a mitigation fee if its actions harm the lesser prairie chicken habitat. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce our reserves.

The Migratory Bird Treaty Act implements various treaties and conventions between the United States and certain other nations for the protection of migratory birds. In accordance with this law, the taking, killing or possessing of migratory birds covered under this act is unlawful without a permit. If there is the potential to adversely affect migratory birds as a result of our operations, we may be required to obtain necessary permits to conduct those operations, which may result in specified operating restrictions on a temporary, seasonal, or permanent basis in affected areas and an adverse impact on our ability to develop and produce our reserves.

In summary, we believe we are in substantial compliance with currently applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2014, nor do we anticipate that such expenditures will be material in 2015. However, we regularly have expenditures to comply with environmental laws and those costs continue to increase as our operations expand.

We are also subject to the requirements of the federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements.

ITEM 1A. RISK FACTORS

We are subject to various risks and uncertainties in the course of our business. The following summarizes the known material risks and uncertainties, which may adversely affect our business, financial condition or results of operations. These risks are not the only risks we face. Our business could also be impacted by additional risks and uncertainties not currently known to us or that we currently deem to be immaterial.

Risks Related to Our Business

Volatility of natural gas, NGLs and oil prices significantly affects our cash flow and capital resources and could hamper our ability to produce natural gas, NGLs, crude oil and condensate economically

Natural gas, NGLs and oil prices are volatile, and a decline in prices adversely affects our profitability and financial condition. The oil and gas industry is typically cyclical, and we expect the volatility to continue. Between 2011 and 2014, the average NYMEX monthly settlement price of natural gas has been as high as $5.56 per mcf and as low as $2.04 per mcf. During that same time frame, the average NYMEX monthly oil settlement price was as high as $110.04 per barrel and as low as $59.29 per barrel. Recently, natural gas and oil prices have declined significantly with the average NYMEX monthly settlement price for natural gas for February 2015 falling to $2.87 per mcf and the monthly settlement for crude oil falling to $47.33 per barrel in January 2015. Likewise, NGLs have suffered significant recent declines in realized prices. NGLs are made up of ethane, propane, isobutane, normal butane and natural gasoline, all of which have different uses and different pricing characteristics. A further or extended decline in commodity prices could materially and adversely affect our business, financial condition and results of operations. Natural gas prices are likely to affect us more than oil prices because approximately 67% of our December 31, 2014 proved reserves are natural gas.

Natural gas, NGLs and oil prices fluctuate in response to changes in supply and demand, market uncertainty and other factors that are beyond our control. Long-term supply and demand for natural gas, NGLs and oil is uncertain and subject to a myriad of factors such as:

- the domestic and foreign supply of natural gas, NGLs and oil;
- the price, availability and demand for alternative fuels and sources of energy;
- weather conditions;
- the level of consumer demand for natural gas, NGLs and oil;
- the price and level of foreign imports;
- U.S. domestic and worldwide economic conditions;
- the availability, proximity and capacity of transportation facilities, processing and storage facilities;
- the effect of worldwide energy conservation efforts;
- political conditions in natural gas and oil producing regions; and
- domestic (federal, state and local) and foreign governmental regulations and taxes.

Lower natural gas, NGLs and oil prices may not only decrease our revenues on a per unit basis but also may reduce the amount of natural gas, NGLs and oil that we can economically produce. A reduction in production could result in a shortfall in expected cash flows and require a reduction in capital spending or require additional borrowing. Without the ability to fund capital expenditures, we would be unable to replace reserves which would negatively affect our future rate of growth. Lower natural gas, NGLs and oil prices may also result in a reduction in the borrowing base under our bank credit facility, which is determined by our lenders at their discretion, taking into account the value of our estimated proved reserves, which is adversely affected by declines in natural gas, NGLs and oil prices. The borrowing base under our bank credit facility is subject to redetermination annually each May and for event driven unscheduled redeterminations.

Producing natural gas, NGLs and oil may involve unprofitable efforts. As of December 31, 2014, the relationship between the price of oil and the price of natural gas continues to be at an historically wide spread. Normally, natural gas liquids production is a by-product of natural gas production. Due to the current differences in prices, we and other producers may choose to sell natural gas at below cost, or otherwise dispose of natural gas to allow for the profitable sale of only NGLs and condensate. Over the past four years, the average Mont Belvieu NGL composite has been as high as $1.31 per gallon and as low as $0.44 per gallon.

Information concerning our reserves and future net cash flow estimates is uncertain

There are numerous uncertainties inherent in estimating quantities of proved natural gas and oil reserves and their values, including many factors beyond our control. Estimates of proved reserves are by their nature uncertain and depend on many assumptions relating to current and further economic conditions and commodity prices. Although we believe these estimates are reasonable, actual production, revenues and costs to develop will likely vary from estimates and these variances could be material.

Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of natural gas and oil that cannot be directly measured. As a result, different petroleum engineers, each using industry-accepted geologic and engineering practices and scientific methods, may calculate different estimates of reserves and future net cash flows based on the same available data. Because of the subjective nature of natural gas, NGLs and oil reserve estimates, each of the following items may differ materially from the amounts or other factors estimated:

- the amount and timing of natural gas, NGLs and oil production;
- the revenues and costs associated with that production;
- the amount and timing of future development expenditures; and
- future commodity prices.

The discounted future net cash flows from our proved reserves included in this report should not be considered as the market value of the reserves attributable to our properties. As required by generally accepted accounting principles, the estimated discounted future net revenues from our proved reserves are based on a twelve month average price (first day of the month) while cost estimates are based on current year-end economic conditions. Actual future prices and costs may be materially higher or lower. In addition, the ten percent discount factor that is required to be used to calculate discounted future net revenues for reporting purposes under generally accepted accounting principles is not necessarily the most appropriate discount factor based on the cost of capital in effect from time to time and risks associated with our business and the oil and gas industry in general.

If natural gas, NGLs and oil prices decrease or drilling efforts are unsuccessful, we may be required to record writedowns of our natural gas and oil properties

In the past we have been required to write down the carrying value of certain of our natural gas and oil properties, and there is a risk that we will be required to take additional writedowns in the future. Writedowns may occur when natural gas and oil prices are low, or if we have downward adjustments to our estimated proved reserves, increases in our estimates of operating or development costs, deterioration in our drilling results or mechanical problems with wells where the cost to redrill or repair is not supported by the expected economics.

Accounting rules require that the carrying value of natural gas and oil properties be periodically reviewed for possible impairment. Impairment is recognized for the excess of book value over fair value when the book value of a proven property is greater than the expected undiscounted future net cash flows from that property and on acreage when conditions indicate the carrying value is not recoverable. We may be required to write down the carrying value of a property based on natural gas and oil prices at the time of the impairment review, or as a result of continuing evaluation of drilling results, production data, economics, divestiture activity, and other factors. A write down constitutes a non-cash charge to earnings and does not impact cash or cash flows from operating activities; however, it reflects our long-term ability to recover an investment and reduces our reported earnings and increases our leverage ratios.

Significant capital expenditures are required to replace our reserves

Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flow from operations, our bank credit facility and debt and equity issuances. We have also engaged in asset monetization transactions. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of natural gas, NGLs and oil and our success in developing and producing new reserves. If our access to capital were limited due to various factors, which could include a decrease in revenues due to lower natural gas, NGLs and oil prices or decreased production or deterioration of the credit and capital markets, we would have a reduced ability to replace our reserves. We may not be able to incur additional bank debt, issue debt or equity, engage in asset monetization or access other methods of financing on an economic basis to meet our reserve replacement requirements.

The amount available for borrowing under our bank credit facility is subject to a borrowing base, which is determined by our lenders, at their discretion, taking into account our estimated proved reserves and is subject to periodic redeterminations based on pricing models determined by the lenders at such time. Declines in natural gas, NGLs and oil prices adversely impact the value of our estimated proved reserves and, in turn, the market values used by our lenders to determine our borrowing base and could result in a determination to lower our borrowing base. Recently, natural gas, NGLs and oil prices have declined significantly. A further or extended decline is commodity prices could materially and adversely affect our business, financial condition and results of operation.

Our future success depends on our ability to replace reserves that we produce

Because the rate of production from natural gas and oil properties generally declines as reserves are depleted, our future success depends upon our ability to economically find or acquire and produce additional natural gas, NGLs and oil reserves. Except to the extent that we acquire additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline as reserves are produced. Future natural gas, NGLs and oil production, therefore, is highly dependent upon our level of success in acquiring or finding additional reserves that are economically recoverable. We cannot assure you that we will be able to find or acquire and develop additional reserves at an acceptable cost.

We acquire significant amounts of unproved property to further our development efforts. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire both producing and unproved properties as well as lease undeveloped acreage that we believe will enhance growth potential and increase our earnings over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our initial investments. Additionally, there can be no assurance that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

Drilling is an uncertain and costly activity

The cost of drilling, completing, and operating a well is often uncertain, and many factors can adversely affect the economics of a well. Our efforts will be uneconomical if we drill dry holes or wells that are productive but do not produce enough natural gas, NGLs and oil to be commercially viable after drilling, operating and other costs. There is no way to conclusively know in advance of drilling and testing whether any particular prospect will yield natural gas, NGLs or oil in commercially viable quantities. Furthermore, our drilling and producing operations may be curtailed, delayed, or canceled as a result of a variety of factors, including:

- increases in the costs, shortages or delivery delays of drilling rigs, equipment, water for hydraulic fracturing services, labor, or other services;
- unexpected operational events and drilling conditions;
- reductions in natural gas, NGLs and oil prices;
- limitations in the market for natural gas, NGLs and oil;
- adverse weather conditions;
- facility or equipment malfunctions;
- equipment failures or accidents;
- title problems;
- pipe or cement failures;
- compliance with, or changes in, environmental, tax and other governmental requirements;
- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, and unauthorized discharges of toxic gases;
- lost or damaged oilfield drilling and service tools;
- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- pressure or irregularities in formations;
- fires;
- natural disasters;
- surface craterings and explosions; and
- uncontrollable flows of oil, natural gas or well fluids.

If any of these factors were to occur, we could lose all or a part of our investment, or we could fail to realize the expected benefits, either of which could materially and adversely affect our revenue and profitability.

Our identified drilling locations are scheduled out over multiple years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling

Our management team has specifically identified and scheduled certain drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including natural gas and oil prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory and zoning approvals and other factors. Because of these uncertain factors, we do not know if the numerous drilling locations we have identified will ever be drilled. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the drilling locations are obtained, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified. In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our business and results of operations.

Our producing properties are concentrated in the Appalachian Basin, making us vulnerable to risks associated with operating in one geographic area

Our producing properties are geographically concentrated in the Appalachian Basin in Pennsylvania, Virginia and West Virginia. At December 31, 2014, 96% of our total estimated proved reserves were attributable to properties located in this area with 86% in Pennsylvania alone. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, state politics, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages or interruption of the processing or transportation of crude oil, condensate, natural gas or NGLs.

New technologies may cause our current exploration and drilling methods to become obsolete

There have been rapid and significant advancements in technology in the natural gas and oil industry, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial increase in cost. Further, competitors may obtain patents which might prevent us from implementing new technologies. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. One or more of the technologies that we currently use or that we may implement in the future may become obsolete. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are unable to maintain technological advancements consistent with industry standards, our operations and financial condition may be adversely affected.

Our indebtedness could limit our ability to successfully operate our business

We are leveraged and our exploration and development program will require substantial capital resources depending on the level of drilling and the expected cost of services. Our existing operations will also require ongoing capital expenditures. In addition, if we decide to pursue additional acquisitions, our capital expenditures will increase, both to complete such acquisitions and to explore and develop any newly acquired properties.

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

- we may be required to dedicate a substantial portion of our cash flows from operations to the payment of our indebtedness, reducing the funds available for our operations;
- a portion of our borrowings are at variable rates of interest, making us vulnerable to increases in interest rates;
- we may be more highly leveraged than some of our competitors, which could place us at a competitive disadvantage;
- our degree of leverage may make us more vulnerable to a downturn in our business or the general economy;
- we are subject to numerous financial and other restrictive covenants contained in our existing debt agreements, which restrict our ability to engage in certain activities and could limit our growth, and the breach of such covenants, which

could materially and adversely impact our financial performance;
our debt level could limit our flexibility to grow the business and in planning for, or reacting to, changes in our business and the industry in which we operate; and
we may have difficulties borrowing money in the future.

Despite our current levels of indebtedness, we still may be able to incur substantially more debt. This could further increase the risks described above. In addition to those risks above, we may not be able to obtain funding on acceptable terms.

Any failure to meet our debt obligations could harm our business, financial condition and results of operations

We expect our earnings and cash flow to vary significantly from year to year due to the cyclical nature of our business. If our cash flow and capital resources are insufficient to fund our debt obligations, we may be forced to sell assets, seek additional equity or restructure our debt. Our ability to restructure our debt will depend on the condition of the capital markets and our financial condition at such time. Any restructuring of debt could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our operations. The terms of existing or future debt instruments may restrict us from adopting some of these alternatives. In addition, any failure to make scheduled payments of interest and principal on our outstanding indebtedness would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness on acceptable terms. Our cash flow and capital resources may be insufficient for payment of interest on and principal of our debt in the future and any such alternative measures may be unsuccessful or may not permit us to meet scheduled debt service obligations, which could cause us to default on our obligations and impair our liquidity.

We are subject to financing and interest rate exposure risks

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in our credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. For example, at December 31, 2014, approximately 76% of our debt is at fixed interest rates with the remaining 24% subject to variable interest rates.

Disruptions or volatility in the global finance markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results. We are exposed to some credit risk related to our bank credit facility to the extent that one or more of our lenders may be unable to provide necessary funding to us under our existing revolving line of credit if it experiences liquidity problems.

A financial downturn or negative credit market conditions may have lasting effects on our liquidity, business and financial condition that we cannot predict

Liquidity is essential to our business. Our liquidity could be substantially negatively affected by an inability to obtain capital in the long-term or short-term debt capital markets or equity capital markets or an inability to access bank financing. A prolonged credit crisis or turmoil in the domestic or global financial systems could materially affect our liquidity, business and financial condition. These conditions have adversely impacted financial markets previously and created substantial volatility and uncertainty, and could do so again, with the related negative impact on global economic activity and the financial markets. Negative credit market conditions could materially affect our liquidity and may inhibit our lenders from fully funding our bank credit facility or cause them to make the terms of our bank credit facility costlier and more restrictive. We are subject to annual reviews, as well as unscheduled reviews, of our borrowing base under our bank credit facility, and we do not know the results of future redeterminations or the effect of then-current oil and natural gas prices on that process. A weak economic environment could also adversely affect the collectability of our trade receivables or performance by our suppliers and cause our commodity derivative arrangements to be ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection. Additionally, negative economic conditions could lead to reduced demand for natural gas, NGLs and oil or lower prices for natural gas and oil, which could have a negative impact on our revenues.

Derivative transactions may limit our potential gains and involve other risks

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

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

- our production is less than expected;
- the counterparties to our futures contracts fail to perform on their contract obligations; or
- an event materially impacts natural gas, NGLs or oil prices or the relationship between the hedged price index and the natural gas or oil sales price.

We cannot assure you that any derivative transaction we may enter into will adequately protect us from declines in the prices of natural gas, NGLs or oil. On the other hand, where we choose not to engage in derivative transactions in the future, we may be more adversely affected by changes in natural gas, NGLs or oil prices than our competitors who engage in derivative transactions. Lower natural gas and oil prices may also negatively impact our ability to enter into derivative contracts at favorable prices.

Many of our current and potential competitors have greater resources than we have and we may not be able to successfully compete in acquiring, exploring and developing new properties

We face competition in every aspect of our business, including, but not limited to, acquiring reserves and leases, obtaining goods, services and employees needed to operate and manage our business and marketing natural gas, NGLs or oil. Competitors include multinational oil companies, independent production companies and individual producers and operators. Many of our competitors have greater financial and other resources than we do. As a result, these competitors may be able to address these competitive factors more effectively than we can or weather industry downturns more easily than we can. For more discussion regarding competition, see “Items 1 and 2. Business and Properties – Competition.”

We could experience periods of higher costs if commodity prices rise. These increases could reduce our profitability, cash flow and ability to complete development activities as planned

Historically, our capital and operating costs have risen during periods of increasing oil, NGLs and gas prices. These cost increases result from a variety of factors beyond our control, such as increases in the cost of electricity, steel and other raw materials that we and our vendors rely upon; increased demand for labor, services and materials as drilling activity increases; and increased taxes. Increased levels of drilling activity in the natural gas and oil industry in recent periods have led to increased costs of some drilling equipment, materials and supplies. Such costs may rise faster than increases in our revenue, thereby negatively impacting our profitability, cash flow and ability to complete development activities as scheduled and on budget.

The natural gas and oil industry is subject to extensive regulation

The natural gas and oil industry is subject to various types of regulations in the United States by local, state and federal agencies. Legislation affecting the industry is under constant review for amendment or expansion, frequently increasing our regulatory burden. Numerous departments and agencies, both state and federal, are authorized by statute to issue rules and regulations binding on participants in the natural gas and oil industry. Compliance with such rules and regulations often increases our cost of doing business, delays our operations and, in turn, decreases our profitability.

Our operations are subject to numerous and increasingly strict federal, state and local laws, regulations and enforcement policies relating to the environment. We may incur significant costs and liabilities in complying with existing or future environmental laws, regulations and enforcement policies and may incur costs arising out of property or natural resource damage or injuries to employees and other persons. These costs may result from our current and former operations and even may be caused by previous owners of property we own or lease or relate to third party sites where we have taken materials for recycling or disposal. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties as well as corrective action orders. Matters subject to regulation include:

- the amounts and types of substances and materials that may be released into the environment;
- response to unexpected releases to the environment;
- reports and permits concerning exploration, drilling, production and other regulated activities;
- the spacing of wells;
- unitization and pooling of properties;
- calculating royalties on oil and gas produced under federal and state leases; and
- taxation.

Under these laws and regulations, we could be liable for personal injuries, property damages, oil spills, discharges of hazardous materials, remediation and clean-up costs, natural resource damages and other environmental damages. We also could be required to install expensive pollution control measures or limit or cease activities on lands located within wilderness, wetlands or other environmentally or politically sensitive areas. If we incur these costs or damages it may reduce or eliminate funds available for exploration, development or acquisitions or cause us to incur losses.

The subject of climate change is receiving increasing attention from scientists, legislators, governmental agencies and the general public. There is an ongoing debate as to the extent to which our climate is changing, the potential causes of this change and its potential impacts. Some attribute global warming to increased levels of GHGs, including carbon dioxide and methane, which has led to significant legislative and regulatory efforts to limit GHG emissions.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. However, there have been a number of regulatory initiatives to address GHG emissions, which include the establishing of Title V and PSD permitting reviews for GHG emissions from certain large stationary sources that are already major potential sources of certain principal, or criteria, pollutant emissions, and the implementation of a GHG monitoring and reporting program for certain sectors of the natural gas and oil industry, including onshore and production, which includes certain of our operations. A number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs, in which major sources of GHG emissions acquire and surrender emission allowances in return for emitting those GHGs. The outcome of federal and state actions to address global climate change could result in a variety of regulatory programs including potential new regulations to control or restrict emissions, taxes or other charges to deter emissions of GHGs, energy efficiency requirements to reduce demand, or other regulatory actions. For example, pursuant to President Obama's Strategy to Reduce Methane Emissions, the Obama Administration announced on January 14, 2015, that EPA is expected to propose in the summer of 2015 and finalize in 2016 new regulations that will set methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities as part of the Administration's efforts to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025. These actions could:

- result in increased costs associated with our operations;
- increase other costs to our business;
- affect the demand for natural gas; and
- impact the prices we charge our customers.

Adoption of federal or state requirements mandating a reduction in GHG emissions could have far-reaching and significant impacts on the energy industry and the U.S. economy. We cannot predict the potential impact of such laws or regulations on our future consolidated financial condition, results of operations or cash flows. For more information regarding the environmental regulation of our business, see "Items 1 and 2. Business and Properties – Environment and Occupational Health and Safety Matters."

Our business is subject to operating hazards that could result in substantial losses or liabilities that may not be fully covered under our insurance policies

Natural gas, NGLs and oil operations are subject to many risks, including well blowouts, craterings, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, pipe or cement failures, pipeline ruptures or spills, vandalism, pollution, releases of toxic gases, adverse weather conditions or natural disasters, and other environmental hazards and risks. If any of these hazards occur, we could sustain substantial losses as a result of:

- injury or loss of life;
- severe damage to or destruction of property, natural resources and equipment;
- pollution or other environmental damage;
- investigatory and cleanup responsibilities;
- regulatory investigations and penalties or lawsuits;
- suspension of operations; and
- repairs to resume operations.

We maintain insurance against many, but not all, potential losses or liabilities arising from our operations in accordance with what we believe are customary industry practices and in amounts and at costs that we believe to be prudent and commercially practicable. Our insurance includes deductibles that must be met prior to recovery, as well as sub-limits and/or self-insurance. Additionally, our insurance is subject to exclusions and limitations. Our insurance does not cover every potential risk associated with our operations, including the potential loss of significant revenues. We can provide no assurance that our coverage will adequately protect us against liability from all potential consequences, damages and losses.

We currently have insurance policies covering our operations that include coverage for general liability, excess liability, physical damage to our oil and gas properties, operational control of wells, oil pollution, third-party liability, workers' compensation and employer's liability and other coverages. Consistent with insurance coverage generally available to the industry, our insurance policies provide limited coverage for losses or liabilities relating to pollution, with coverage for sudden and accidental occurrences. For example, we maintain operator's extra expense coverage provided by third-party insurers for obligations, expenses or claims that we may incur from a sudden incident that results in negative environmental effects, including obligations, expenses or claims related to seepage and pollution, cleanup and containment, evacuation expenses and control of the well (subject to policy terms and conditions). In the specific event of a well blowout or out-of-control well resulting in negative environmental effects, such operator's extra expense coverage would be our primary source of coverage, with the general liability and excess liability coverage referenced above also providing certain coverage.

In the event we make a claim under our insurance policies, we will be subject to the credit risk of the insurers. Volatility and disruption in the financial and credit markets may adversely affect the credit quality of our insurers and impact their ability to pay claims.

Further, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. Some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable, and we may elect to maintain minimal or no insurance coverage. If we incur substantial liability from a significant event and the damages are not covered by insurance or are in excess of policy limits, then we would have lower revenues and funds available to us for our operations, that could, in turn, have a material adverse affect on our business, financial condition and results of operations.

Additionally, we rely to a large extent on facilities owned and operated by third parties, and damage to or destruction of those third-party facilities could affect our ability to process, transport and sell our production. To a limited extent, we maintain business interruption insurance related to a third-party processing plant in Pennsylvania where we are insured for potential losses from the interruption of production caused by loss of or damage to the processing plant.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by the FERC as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests the FERC has used to establish a pipeline’s status as a gatherer not subject to regulation as a natural gas company. However, we have not received a declaratory order from the FERC regarding our natural gas gathering pipelines and the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by the FERC, the courts or Congress.

While we believe our natural gas gathering operations are generally exempt from FERC regulation under the NGA, our gas gathering operations may be subject to certain FERC reporting and posting requirements in a given year. The FERC has issued a final rule requiring certain participants in the natural gas market, including certain gathering facilities and natural gas marketers that engage in a minimum level of natural gas sales or purchases, to submit annual reports to the FERC on the aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to, the formation of price indices.

Other FERC regulations may indirectly impact our businesses and the markets for products derived from these businesses. The FERC’s policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on open access transportation, gas quality, ratemaking, capacity release and market-center promotion, may indirectly affect the intrastate natural gas market. In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that the FERC will continue this approach as it considers matters such as pipelines rates and rules and policies that may affect rights of access to transportation capacity. For more information regarding the regulation of our operations, see “Items 1 and 2. Business and Properties – Governmental Regulation.”

Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines

Under EPAct 2005, the FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation. While our operations have not been regulated as a natural gas company by the FERC under the NGA, the FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to the FERC annual reporting requirements. We also must comply with the anti-market manipulation rules enforced by the FERC. Additional rules and legislation pertaining to those and other matters may be considered or adopted by the FERC from time to time. Failure to comply with those regulations in the future could subject Range to civil penalty liability. For more information regarding the regulation of our operations, see “Items 1 and 2. Business and Properties – Governmental Regulation.”

Certain federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated, and additional state taxes on natural gas extraction may be imposed, as a result of future legislation

Legislation has been proposed that would, if enacted into law, make significant changes to U.S. federal income tax laws, including the elimination of certain U.S. federal income tax benefits currently available to oil and gas exploration and production companies. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective. As of December 31, 2014, we had a tax basis of $2.2 billion related to prior years capitalized intangible drilling costs, which will be amortized over the next five years.

The passage of this legislation or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available with respect to natural gas and oil exploration and development, and any such change could negatively affect our financial condition and results of operations.

In February 2012, the state legislature of Pennsylvania passed a new natural gas impact fee in Pennsylvania, where the majority of our acreage in the Marcellus Shale is located. The legislation imposes an annual fee on natural gas and oil operators for each well drilled for a period of fifteen years. Much like a severance tax, the fee is on a sliding scale set by the Public Utility Commission and is based on two factors: changes in the Consumer Price Index and the average NYMEX natural gas prices from the last day of each month. The passage of this legislation increases the financial burden on our operations in the Marcellus Shale. There can be no assurance that the impact fee will remain as currently structured or that additional taxes will not be imposed. In addition, there are currently proposals by various Pennsylvania state lawmakers to enact a severance tax in addition to the impact fee already in place.

Changes in laws or regulations relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays and adversely affect our production

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate hydrocarbon (natural gas and oil) production. We find that the use of hydraulic fracturing is necessary to produce commercial quantities of natural gas and oil from many reservoirs, especially shale formations such as the Marcellus Shale. The process is typically regulated by state oil and gas commissions. However, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final Clean Air Act regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; announced its intent to propose in early 2015 effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, for example, in May 2013, the BLM issued a revised proposed rule containing disclosure requirements and other mandates for hydraulic fracturing on federal lands and the agency is now analyzing comments to the proposed rulemaking and is expected to promulgate a final rule in early 2015.

From time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Certain states in which we operate, including Pennsylvania, Texas and West Virginia, have adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosure or well-construction requirements on hydraulic fracturing operations. States could elect to prohibit hydraulic fracturing altogether, as Governor Andrew Cuomo of the State of New York announced in December 2014 with regard to fracturing activities in New York. Local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general and/or hydraulic fracturing in particular. In the event federal, state or local restrictions or prohibitions are adopted in areas where we conduct operations, we may incur significant costs to comply with such requirements or we may experience delays or curtailment in the pursuit of exploration, development, or production activities, and possibly be limited or precluded in the drilling of wells or in the amounts that we are ultimately able to produce from our reserves. Moreover, a number of federal entities are analyzing a variety of environmental issues associated with hydraulic fracturing. For example, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing and the EPA has been pursuing a study begun in 2011 of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a draft final report expected to be issued for peer review and comment by early 2015. These studies and initiatives, or any future studies, depending on their degree of pursuit and any meaningful results obtained, could spur efforts to further regulate hydraulic fracturing.

We use a significant amount of water in our hydraulic fracturing operations. Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our operations, could adversely impact our operations. Moreover, new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. Compliance with environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition.

The enactment of derivatives legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Act”), enacted in July 2010, established federal oversight and regulation of the over-the-counter derivatives market and entities, including Range, that participate in that market. The Act requires the Commodities Futures Trading Commission (the “CFTC”) and the SEC to promulgate rules and regulations implementing the Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position limits rule was vacated by the United States District Court for the District of Columbia in September 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and the associated rules also will require us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements. The CFTC has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. Although we expect to qualify for the end-user exception from the mandatory clearing requirements for swaps entered to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, for uncleared swaps, the CFTC or federal banking regulators may require end-users to enter into credit support documentation and/or post initial and variation margin. Posting of collateral could impact liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flows. The proposed margin rules are not yet final, and therefore the impact of those provisions to us is uncertain at this time.

The full impact of the Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The Act and new regulations could significantly increase the cost of derivative contracts or materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter or reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Act and regulations implementing the Act, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

Finally, the Act was intended, in part, to reduce the volatility of oil and gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and gas. Our revenues could therefore be adversely affected if a consequence of the Act and implementing regulations is to lower commodity prices.

Laws and regulations pertaining to threatened and endangered species could delay or restrict our operations and cause us to incur substantial costs

Various federal and state statutes prohibit certain actions that adversely affect endangered or threatened species and their habitats, migratory birds, wetlands and natural resources. These statutes include the ESA, the Migratory Bird Treaty Act, the CWA and CERCLA. The FWS may designate critical habitat and suitable habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or oil and gas development. If harm to species or damages to wetlands, habitat or natural resources occur or may occur, government entities or, at times, private parties may act to prevent oil and gas exploration or development activities or seek damages for harm to species, habitat or natural resources resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and, in some cases, may seek criminal penalties. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the FWS is required to consider listing numerous species as endangered or threatened under the ESA before completion of the agency's 2017 fiscal year, and in March 2014, listed the lesser prairie chicken as a threatened species in a five-state region, including Texas, where we have operations. The designation of previously unprotected species as threatened or endangered in areas where we conduct operations could cause us to incur increased costs arising from species protection measures or could result in limitations on its exploration and production activities that could have an adverse effect on our ability to develop and produce reserves.

Our business depends on natural gas and oil transportation and NGLs processing facilities, most of which are owned by others and depends on our ability to contract with those parties

Our ability to sell our natural gas, NGLs and oil production depends in part on the availability, proximity and capacity of pipeline systems and processing facilities owned by third parties and our ability to contract with those third parties. The lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Although we have some contractual control over the transportation of our product, material changes in these business relationships, including the financial condition of these third parties, could materially affect our operations. In some

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cases, we do not purchase firm transportation on third party facilities and therefore, our production transportation can be interrupted by those having firm arrangements. We have entered into firm transportation arrangements in the Marcellus Shale where we are obligated to pay fees on minimum volumes regardless of actual volume throughput. We have also entered into long-term agreements with third parties to provide natural gas gathering and processing services in the Marcellus Shale. In some cases, the capacity of gathering systems and transportation pipelines may be insufficient to accommodate potential production from existing and new wells. Federal and state regulation of natural gas and oil production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport natural gas, NGLs and oil. If any of these third party pipelines and other facilities become partially or fully unavailable to transport or process our product, or if the natural gas quality specifications for a natural gas pipeline or facility changes so as to restrict our ability to transport natural gas on those pipelines or facilities, our revenues could be adversely affected.

The disruption of third-party facilities due to maintenance and/or weather could negatively impact our ability to market and deliver our products. In particular, the disruption of certain third-party natural gas processing facilities in the Marcellus Shale could materially affect our ability to market and deliver natural gas production in that area. We have no control over when or if such facilities are restored and generally have no control over what prices will be charged. A total shut-in of production could materially affect us due to a lack of cash flow, and if a substantial portion of the production is hedged at lower than market prices, those financial hedges would have to be paid from borrowings absent sufficient cash flow.

Currently, there is little demand, or facilities to supply the existing demand elsewhere, for ethane in the Appalachian region. We have announced three ethane agreements wherein we have contracted to either sell or transport ethane from our Marcellus Shale area, two of which began initial deliveries in late 2013, and the final one expected to begin operations in mid-2015. We cannot assure you that all these facilities will become or will remain available.

Acquisitions are subject to the risks and uncertainties of evaluating reserves and potential liabilities and may be disruptive and difficult to integrate into our business

We could be subject to significant liabilities related to our acquisitions. It generally is not feasible to review in detail every individual property included in an acquisition. Ordinarily, a review is focused on higher-valued properties. However, even a detailed review of all properties and records may not reveal existing or potential problems in all of the properties, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. We do not always inspect every well we acquire, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is performed.

In addition, there is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our acquisition strategy is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Our ability to pursue our acquisition strategy may be hindered if we are unable to obtain financing on terms acceptable to us or regulatory approvals.

Acquisitions often pose integration risks and difficulties. In connection with recent and future acquisitions, the process of integrating acquired operations into our existing operations may result in unforeseen operating difficulties and may require significant management attention and financial resources that would otherwise be available for the ongoing development or expansion of existing operations. Future acquisitions could result in our incurring additional debt, contingent liabilities, expenses and diversion of resources, all of which could have a material adverse effect on our financial condition and operating results.

We may be unable to dispose of nonstrategic assets on attractive terms, and may be required to retain liabilities for certain matters

We regularly review our property base for the purpose of identifying nonstrategic assets, the disposition of which would increase capital resources available for other activities and create organizational and operational efficiencies. Various factors could materially affect our ability to dispose of nonstrategic assets or complete announced dispositions, including the availability of purchasers willing to purchase the nonstrategic assets at prices acceptable to us. Sellers typically retain certain liabilities for certain matters. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a sale, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

Our success depends on key members of our management and our ability to attract and retain experienced technical and other professional personnel

Our success is highly dependent on our management personnel and none of them is currently subject to an employment contract. The loss of one or more of these individuals could have a material adverse effect on our business. Furthermore, competition for experienced technical and other professional personnel remains strong. If we cannot retain our current personnel or attract additional experienced personnel, our ability to compete could be adversely affected. Also, the loss of experienced personnel could lead to a loss of technical expertise.

We have limited control over the activities on properties we do not operate

Other companies operate some of the properties in which we have an interest. We operate approximately 96% of our wells, as of December 31, 2014. We have limited ability to influence or control the operation or future development of non-operated properties or the amount of capital expenditures that we are required to fund with respect to them. The failure of an operator of our wells to adequately perform operations, an operator’s breach of the applicable agreements or an operator’s failure to act in ways that are in our best interest could reduce our production and revenues. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital in drilling or acquisitions activities and lead to unexpected future costs.

We exist in a litigious environment

Any constituent could bring suit regarding our existing or planned operations or allege a violation of an existing contract. Any such action could delay when planned operations can actually commence or could cause a halt to existing production until such alleged violations are resolved by the courts. Not only could we incur significant legal and support expenses in defending our rights, but halting existing production or delaying planned operations could impact our future operations and financial condition. Such legal disputes could also distract management and other personnel from their primary responsibilities.

Our business could be negatively affected by security threats, including cybersecurity threats, and other disruptions

As a natural gas and oil producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the security of our facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. The potential for such security threats has subjected our operations to increased risks that could have a material adverse effect on our business. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of sensitive information, critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations or cash flows. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability.

Negative public perception regarding us and/or our industry could have an adverse effect on our operations

Negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about hydraulic fracturing, oil spills, and explosions of natural gas transmission lines, may lead to regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we need to conduct our operations to be withheld, delayed, or burdened by requirements that restrict our ability to profitably conduct our business.

Conservation measures and technological advances could reduce demand for oil and natural gas

Fuel conservation measures, alternative fuel requirements, governmental requirements for renewable energy resources, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our financial statements are complex

Due to United States generally accepted accounting principles and the nature of our business, our financial statements continue to be complex, particularly with reference to derivatives, asset retirement obligations, equity awards, deferred taxes and the accounting for our deferred compensation plans. We expect such complexity to continue and possibly increase.

Risks Related to Our Common Stock

Common stockholders will be diluted if additional shares are issued

In 2005, 2006, 2007 and 2008, we sold 52.7 million shares of common stock to finance acquisitions or pay down our outstanding bank credit facility. In 2009 and 2010, we issued 1.1 million shares of common stock to purchase acreage in the Marcellus Shale. In 2014, we issued approximately 4.6 million shares of common stock in a public stock offering with the proceeds used to redeem our 8% senior subordinated notes due 2019. Our ability to repurchase securities for cash is limited by our bank credit facility and our senior subordinated note agreements. We also issue restricted stock, stock appreciation rights and performance share units to our employees and directors as part of their compensation. In addition, we may issue additional shares of common stock, additional subordinated notes or other securities or debt convertible into common stock, to extend maturities or fund capital expenditures, including acquisitions. If we issue additional shares of our common stock in the future, it may have a dilutive effect on our current outstanding stockholders.

Dividend limitations

Limits on the payment of dividends and other restricted payments, as defined, are imposed under our bank credit facility and under our senior subordinated note agreements. These limitations may, in certain circumstances, limit or prevent the payment of dividends independent of our dividend policy.

Our stock price may be volatile and you may not be able to resell shares of our common stock at or above the price you paid

The price of our common stock fluctuates significantly, which may result in losses for investors. The market price of our common stock has been volatile. From January 1, 2012 to December 31, 2014, the price of our common stock reported by the New York Stock Exchange ranged from a low of $51.83 per share to a high of $95.41 per share. We expect our stock to continue to be subject to fluctuations as a result of a variety of factors, including factors beyond our control. These factors include:

- changes in natural gas, NGLs and oil prices;
- variations in quarterly drilling, recompletions, acquisitions and operating results;
- changes in governmental regulation and/or taxation;
- changes in financial estimates by securities analysts;
- changes in market valuations of comparable companies;
- additions or departures of key personnel; or
- future sales of our stock and changes in our capital structure.

We may fail to meet expectations of our stockholders or of securities analysts at some time in the future and our stock price could decline as a result.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

We are the subject of, or party to, a number of pending or threatened legal actions and claims arising in the ordinary course of our business. While many of these matters involve inherent uncertainty, we believe that the amount of 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.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market for Common Stock

Our common stock is listed on the New York Stock Exchange ("NYSE") under the symbol "RRC." During 2014, trading volume averaged approximately 2.0 million shares per day. The following table shows the quarterly high and low sale prices and cash dividends declared as reported on the NYSE composite tape for the past two years.

	High	Low	Cash Dividends Declared
2013:			
First quarter	$83.15	$61.25	$ 0.04
Second quarter	81.13	71.14	0.04
Third quarter	85.23	74.66	0.04
Fourth quarter	85.49	72.54	0.04
2014:			
First quarter	$90.76	$79.28	$ 0.04
Second quarter	95.41	82.63	0.04
Third quarter	87.37	66.98	0.04
Fourth quarter	74.64	51.83	0.04

Between January 1, 2015 and February 23, 2015, the common stock traded at prices between $44.17 and $55.74 per share. Our senior subordinated notes are not listed on an exchange, but trade over-the-counter.

Holders of Record

On February 23, 2015, there were approximately 1,139 holders of record of our common stock.

Dividends

The payment of dividends is subject to declaration by the Board of Directors and depends on earnings, capital expenditures and various other factors. The Board of Directors declared quarterly dividends of $0.04 per common share for each of the four quarters of 2014, 2013 and 2012. The bank credit facility and our senior subordinated notes allow for the payment of common and preferred dividends, with certain limitations. The determination of the amount of future dividends, if any, to be declared and paid is at the sole discretion of our Board of Directors and will depend upon our level of earnings and capital expenditures and other matters that the board deems relevant. Dividends on Range common stock are limited to our legally available funds. For more information, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

Stockholder Return Performance Presentation*

The following graph is included in accordance with the SEC's executive compensation disclosure rules. This historic stock price performance is not necessarily indicative of future stock performance. The graph compares the change in the cumulative total return of Range's common stock, the Dow Jones U.S. Exploration and Production Index, and the S&P 500 Index for the five years ended December 31, 2014. The graph assumes that $100 was invested in the Company's common stock and each index on December 31, 2009, and that dividends were reinvested.

	2009	2010	2011	2012	2013	2014
Range Resources Corporation	$100	$91	$125	$127	$171	$109
S&P 500 Index	100	115	117	136	180	205
DJ U.S. Expl. & Prod. Index	100	117	112	118	156	139

*The performance graph and the information contained in this section is not "soliciting material," is being "furnished" not "filed" with the SEC and is not to be incorporated by reference into any of our filings under the Securities Act or the Exchange Act whether made before or after the date hereof and irrespective of any general incorporation language contained in such filing.

ITEM 6. SELECTED FINANCIAL DATA AND PROVED RESERVE DATA

The following table shows selected financial information for the five years ended December 31, 2014. Significant producing property dispositions may affect the comparability of year-to-year financial and operating data. In the first half of 2014, we completed the Conger Exchange where we sold our Conger properties located in Glasscock and Sterling Counties, Texas in exchange for producing properties and other assets in Virginia and $145.0 million in cash, before closing adjustments. In the first half of 2013, we sold certain Delaware and Permian Basin properties in Southeast New Mexico and West Texas for proceeds of $275.0 million. In the first half of 2011, we sold our Barnett Shale properties for proceeds of $889.3 million, including certain derivative contracts assumed by the buyer and these operations are reflected as discontinued operations. In the first half of 2010, we sold our Ohio properties for proceeds of $323.0 million. This information should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," and our consolidated financial statements and related notes included elsewhere in this report (in thousands except per share or per mcfe data).

	Year Ended December 31,				
	2014	2013	2012	2011	2010
Statements of Operations Data:					
Natural gas, NGLs and oil sales	$1,911,989	$1,715,676	$1,351,694	$1,173,266	$823,290
Total revenues and other income	2,711,695	1,862,719	1,457,704	1,230,642	961,397
Total costs and expenses	1,680,810	1,713,140	1,432,648	1,152,379	821,789
Income from continuing operations	634,382	115,722	13,002	42,706	88,698
Discontinued operations, net of taxes	¾	¾	—	15,320	(327,954)
Net income (loss)	634,382	115,722	13,002	58,026	(239,256)
Income from continuing operations per share:					
–Basic	$3.81	$0.71	$0.08	$0.26	$0.56
–Diluted	3.79	0.70	0.08	0.26	0.55
Net income (loss) per share:					
–Basic	3.81	0.71	0.08	0.36	(1.53)
–Diluted	3.79	0.70	0.08	0.36	(1.52)
Costs per mcfe: [a]					
Direct operating expense	$0.35	$0.37	$0.42	$0.60	$0.69
Production and ad valorem tax expense	0.11	0.13	0.24	0.15	0.19
General and administrative expense	0.50	0.85	0.63	0.80	1.01
Interest expense	0.40	0.51	0.61	0.66	0.65
Depletion, depreciation and amortization expense	1.30	1.44	1.62	1.80	1.98
	$2.66	$3.30	$3.52	$4.01	$4.52
Average Daily Production:					
Natural gas (mcf)	786,099	724,735	591,679	397,825	290,815
NGLs (bbls)	51,563	25,356	19,036	14,664	9,864
Oil (bbls)	11,150	10,486	7,790	5,369	5,300
Total mcfe [b]	1,162,374	939,786	752,637	518,019	381,800
Balance Sheets Data:					
Current assets [c]	$570,292	$248,301	$327,614	$315,263	$1,113,570

Current liabilities [d]	755,263	495,561	455,143	511,932	443,690
Natural gas and oil properties, net	7,977,573	6,758,437	6,096,184	5,157,566	4,084,013
Total assets	8,746,780	7,299,086	6,728,735	5,845,470	5,511,714
Bank debt	723,000	500,000	739,000	187,000	274,000
Subordinated notes	2,350,000	2,640,516	2,139,185	1,787,967	1,686,536
Stockholders' equity[e]	3,457,429	2,414,452	2,357,392	2,392,420	2,223,761
Weighted average diluted shares outstanding	164,403	161,407	160,307	159,441	158,428
Cash dividends declared per common share	0.16	0.16	0.16	0.16	0.16
Statements of Cash Flows Data:					
Net cash provided from operating activities	$954,135	$743,538	$647,099	$631,637	$513,322
Net cash used in investing activities	(1,245,456)	(983,436)	(1,528,558)	(547,981)	(798,858)
Net cash provided from (used in) financing activities	291,421	239,994	881,619	(86,412)	287,617
Proved Reserves Data (at end of period):					
Natural gas (Bcf)	6,923	5,666	4,793	4,010	3,567
NGLs (Mmbbls)	516	374	240	142	123
Oil and condensate (Mmbbls)	49	48	45	31	23
Total proved reserves (Bcfe)	10,310	8,202	6,506	5,054	4,442

(a) These are costs we believe fluctuate on a unit-of-production, or per mcfe basis.

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

(c) 2010 includes $877.6 million assets of discontinued operations. 2013 includes $51.4 million of deferred tax assets. 2014 includes $363.0 million of derivative assets compared to $4.4 million in 2013, $137.6 million in 2012, $173.9 million in 2011 and $123.3 million in 2010.

(d) 2013 includes $26.2 million of derivative liabilities compared to $352,000 in 2010. 2014 includes $115.6 million deferred tax liability compared to $37.9 million in 2012, $56.6 million in 2011 and $11.8 million in 2010.

(e) Stockholders' equity includes other comprehensive income of $6.2 million in 2013 compared to $83.9 million in 2012, $156.6 million in 2011 and $67.5 million in 2010. There was no other comprehensive income in 2014.

ITEM 7. 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 "anticipate," "believe," "estimate," "expect," "forecast," "plan," "project," "t "could," "may," "should," "would" or similar words indicating that future outcomes are uncertain. In accordance with "safe harbor" provisions for 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. Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the information under Items 1 and 2. Business and Properties, Item 1A. Risk Factors, Item 6. Selected Financial Data and Item 8. Financial Statements Data in this report. Unless otherwise indicated, the information included herein relates to our continuing operations.

Overview of Our Business

We are an independent natural gas, natural gas liquids ("NGLs") and oil company engaged in the exploration, development and acquisition of natural gas and crude oil properties in the Appalachian and Midcontinent 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. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis.

Our overarching business objective is to build stockholder value through consistent growth in reserves and production on a cost-efficient basis. Our strategy to achieve our business 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 oil reserves. Recently natural gas and crude oil prices have declined significantly. A further or extended decline in commodity prices could materially and adversely affect our business financial condition and results of operations. 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;
- the quantity of natural gas, NGLs and oil we can economically produce; and
- revenues and profitability.

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. Our corporate headquarters is located in Fort Worth, Texas.

Sources of Our Revenues

We derive our revenues from the sale of natural gas, NGLs, oil and condensate that is produced from our properties. Revenues from product sales are a function of the volumes produced, prevailing market prices, product quality, gas Btu content and transportation costs. We generally sell natural gas, NGLs and oil under two types of agreements, which are common in our industry. Both types of agreements include transportation charges. One type of agreement is a netback agreement, under which we sell natural gas and oil at the wellhead and collect a price, net of transportation incurred by the purchaser. In this case, we record revenue at the price we receive from the purchaser. In the case of NGLs, we generally receive a net price from the purchaser (which is net of processing costs) and is also recorded in revenue at the net price we receive from the purchaser. Under the other type of agreement, we sell natural gas or oil at a specific delivery point, pay transportation to a third party and receive proceeds from the purchaser with no transportation deduction. In that case, we record transportation costs as transportation, gathering and compression expense. Also included in natural gas, NGLs and oil sales revenues and derivative fair value income or loss are the effects of derivative accounting. Derivatives included in natural gas, NGLs and oil sales reflect settlements on those derivatives that qualify for hedge accounting. Cash settlements of derivative contracts that are not accounted for as hedges are included in derivative fair value income or loss in the accompanying statements of operations. 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. For more information, see Note 10 to our consolidated financial statements. Brokered natural gas, marketing and other revenues include revenue received from brokered gas or revenue we receive as a result of selling (and buying) natural gas that is not related to our production, revenue from the release of transportation capacity, marketing fees we receive from third parties, transportation revenue we receive from gathering lines we own and equity method investments.

Principal Components of Our Cost Structure

Direct operating. These are day-to-day costs incurred to bring hydrocarbons out of the ground along with the daily costs incurred to maintain our producing properties. Such costs include compensation of our field employees, maintenance, repairs and workover expenses related to our natural gas and oil properties. The majority of these costs are expected to remain a function of supply and demand. Direct operating expenses also include stock-based compensation expense (non-cash) associated with the amortization of restricted stock grants as part of the compensation of field employees.

Transportation, gathering and compression. Under some of our sales arrangements, we sell natural gas and NGLs at a specific delivery point, pay transportation, gathering and compression costs to a third party and receive proceeds from the purchaser with no deduction. Transportation, gathering and compression expense represents costs paid by Range to third parties under these arrangements.

Production and ad valorem taxes. Production taxes are paid on produced natural gas and oil based on a percentage of sales revenue (excluding derivatives) or at fixed rates established by the applicable federal, state or local taxing authorities. Ad valorem taxes are generally based on reserve values at the end of each year. The Pennsylvania impact fee on unconventional natural gas and oil production, which includes the Marcellus Shale, is also included in this category.

Brokered natural gas and marketing. These expenses are gas purchases for brokered gas natural gas that we buy and sell that is not related to our production and overhead, including payroll and benefits for our marketing staff. Brokered natural gas and marketing also includes stock-based compensation expense (non-cash) associated with the amortization of restricted stock, stock appreciation rights (“SARs”) and performance share units (“PSUs”) granted as part of our marketing staff compensation.

Exploration. These are geological and geophysical costs, such as payroll and benefits for the geological and geophysical staff, seismic costs, delay rentals and the costs of unsuccessful exploratory dry holes. Exploration expense also includes stock-based compensation expense (non-cash) associated with the amortization of grants of SARs, PSUs and restricted stock as part of the compensation of our exploration staff.

Abandonment and impairment of unproved properties. This category includes unproved property impairment and expenses associated with lease expirations.

General and administrative. These costs include overhead, such as payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, audit and other professional fees, legal compliance and legal settlements. Included in this category are overhead expense reimbursements we receive from working interest owners of properties, for which we serve as the operator. These reimbursements are received during both the drilling and operational stages of a property’s life. General and administrative expense also includes stock-based compensation expense (non-cash) associated with the amortization of restricted stock, SARs and PSUs granted as part of the compensation of our corporate staff and our directors.

Deferred compensation plan. These costs relate to the increase or decrease in the value of the liability associated with our deferred compensation plan. Our deferred compensation plan gives directors, officers and key employees the ability to defer all or a portion of their salaries and bonuses and invest in our common stock or make other investments at the individual’s discretion. The assets of this plan are held in a grantor trust, are funded on the grant date and are available to satisfy the claims of our creditors in the event of bankruptcy or insolvency.

Interest expense. We typically finance a portion of our cash requirements with borrowings under our bank credit facility and with longer-term debt securities. Included here are also administrative fees associated with our bank credit facility and the amortization of deferred financing costs. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We currently have no capitalized interest.

Depreciation, depletion and amortization. This includes the systematic expensing of the capitalized costs incurred to acquire, explore and develop natural gas, NGLs and oil. As a successful efforts company, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts, and apportion these costs to each unit of production through depreciation, depletion and amortization expense. This expense also includes the systematic, monthly accretion of the future abandonment costs of tangible assets such as wells, service assets, pipelines, and other facilities.

Income taxes. We are subject to state and federal income taxes but are currently not in a cash taxpaying position for federal income taxes, primarily due to the current deductibility and/or accelerated amortization of intangible drilling costs ("IDC"). At this time, we generally do not pay significant state income taxes due to our state net operating loss carryovers and our ability to follow the federal treatment of deducting IDC in most of the states in which we operate. Currently, substantially all of our federal taxes are deferred and we anticipate using all of our federal net operating loss carryforwards. As of December 31, 2014, we have an $8.8 million valuation allowance on the portion of our Oklahoma net loss carryforwards which we do not believe are realizable. For more information, see "Item 1A. Risk Factors-Certain federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated, and additional state taxes on natural gas extraction may be imposed, as a result of future legislation."

Management's Discussion and Analysis of Results of Operations

Overview of 2014 Results

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

- achieved 24% annual production growth;
- achieved 26% annual proved reserve growth;
- drilled 239 net wells with a 99% success rate;
- continued expansion of our activities in the Marcellus Shale by growing production, proving up acreage and acquiring additional unproved acreage;
- reduced direct operating expenses per mcfe 5% from the same period of 2013;
- reduced our DD&A rate 10% from the same period of 2013;
- continued to focus on financial flexibility by redeeming all $300.0 million of 8% senior subordinated notes due in 2019 and achieved a debt per mcfe of proved reserves of $0.30 compared to $0.38 in 2013;
- issued 4.56 million shares of common stock where we received $396.6 million in net proceeds;
- entered into additional commodity-based derivative contracts for 2015 and 2016;
- received $151.7 million of proceeds from the exchange of our Conger properties in West Texas for producing properties and other assets in Virginia and $28.8 million of proceeds from the sale of other miscellaneous non-core oil and gas assets;
- realized $954.1 million of cash flow from operating activities;
- ended the year with stockholders' equity of $3.5 billion; and
- entered into additional firm transportation commitments and sales agreements.

Operationally, our 2014 performance reflects another year of successfully executing our strategy of growth through drilling. Our success enabled us to increase proved reserves by approximately 2.1 Tcfe, which is more than 4 times our 2014 production. As evidenced by history and our current industry environment, the prices at which we sell our production are volatile and we have no control over them. Therefore, to improve our profitability, we focus our efforts on improving operating efficiency. As reservoirs are depleted and production rates decline, per unit production costs will generally increase. To lessen this effect, we concentrate our production in core areas where we can achieve economies of scale to help manage our operating costs.

Acquisitions

During 2014, we spent $226.5 million to acquire unproved acreage compared to $137.5 million in 2013 and $188.8 million in 2012. We continue selective acreage leasing and lease renewals to add to our acreage positions primarily in the Marcellus Shale play in Pennsylvania. See additional information below regarding our exchange during 2014 of properties in West Texas for properties, cash and other assets in Virginia.

Divestitures

Texas. In December 2013, we announced our plan to offer for sale certain of our properties in the Permian Basin. These properties included approximately 73,000 net acres, almost all of which are held by production in Glasscock and Sterling Counties, Texas. In April 2014, we entered into an exchange agreement with EQT Corporation and certain of its affiliates (collectively, "EQT") in which we sold these assets in exchange for producing properties, (including approximately 138,000 net acres) and other EQT assets in Virginia and $145.0 million in cash, before closing adjustments. We closed the exchange transaction in June 2014 and we recognized a pre-tax gain of $282.7 million related to this exchange. In fourth quarter 2014, we also sold miscellaneous proved properties in East Texas for proceeds of $5.0 million and recognized a gain of $467,000.

In December 2012, we announced our plan to offer for sale certain of our Permian and Delaware Basin properties in West Texas and Southeast New Mexico. In February 2013, we announced we had signed a definitive agreement to sell these assets for a price of $275.0 million. We closed this disposition in April 2013 and we recorded a pre-tax gain of $79.1 million. During 2013, we sold miscellaneous unproved and proved property for proceeds of $33.5 million and we recorded a gain of $8.8 million. In March 2012, we sold 75% of a prospect in East Texas, which included unproved properties and a suspended exploratory well to a third party for proceeds of $8.6 million and recorded a pre-tax loss of $10.9 million.

In January 2015, we signed a purchase and sale agreement to sell our remaining West Texas properties for cash proceeds of $10.5 million. The transaction closed in February 2015 with no gain or loss recognized.

Oklahoma. In December 2014, we sold certain oil and gas properties in Western Oklahoma for proceeds of $2.6 million with no gain or loss recognized. In November 2012, we sold certain oil and gas properties in Southern Oklahoma to a third party for gross proceeds of $135.0 million which resulted in a pretax gain of $55.2 million in the year ended December 31, 2012.

Pennsylvania. In December 2014, we sold miscellaneous unproved properties for proceeds of $18.8 million and we recognized a gain of $617,000. In September 2013, we sold our equity method investment in a drilling company for proceeds of $7.0 million and recognized a gain of $4.4 million. In June 2012, we sold a suspended exploratory well in the Marcellus Shale for proceeds of $2.5 million and recorded a pre-tax loss of $2.5 million on this transaction.

2015 Outlook

For 2015, the Board of Directors approved an $870.0 million capital budget for natural gas, NGLs, crude oil and condensate related activities, excluding proved property acquisitions, for which we do not budget. As has been our historical practice, we will periodically review our capital expenditures throughout the year and may adjust the budget based on commodity prices, drilling success and other factors. To the extent, our 2015 capital requirements exceed our internally generated cash flow, proceeds from asset sales, drawing on our committed capacity under our bank credit facility, debt or equity may be issued to fund these requirements. The prices we receive for our natural gas, NGLs and oil production are largely based on current market prices, which are beyond our control. The price risk on a portion of our forecasted natural gas, NGLs and oil production for 2015 is mitigated using commodity derivative contracts and we intend to continue to enter into these transactions. Recently, natural gas and crude oil prices have dropped significantly. In periods of falling prices, the demand for drilling rigs, oilfield supplies and drill pipe is expected to decline but such declines tend to lag behind the declines in natural gas and crude oil prices. In response to the weakened natural gas and crude oil market, we have lowered our 2015 capital budget, which was originally announced in December 2014 at $1.3 billion to $870 million and we have announced a plan to close our Oklahoma City divisional office by mid-2015 which will reduce general and administrative expenses, excluding one-time termination costs. These properties will be operated out of our Fort Worth office.

Market Conditions

Prices for various quantities of natural gas, NGLs and oil that we produce significantly impact our revenues and cash flows. Prices for commodities, such as hydrocarbons, are inherently volatile. Recently, natural gas and crude oil prices have dropped significantly with the average NYMEX monthly settlement price for natural gas falling to $2.87 per mcf for February 2015 and crude oil falling to $47.33 per barrel in January 2015. The following table lists average NYMEX prices for natural gas and oil and the Mont Belvieu NGL composite price for the years ended December 31, 2014, 2013 and 2012.

	Year Ended December 31,		
	2014	2013	2012
Average NYMEX prices [(a)]			
Natural gas (per mcf)	$4.37	$3.67	$2.82
Oil (per bbl)	$92.64	$98.20	$93.36
Mont Belvieu NGL composite (per gallon)	$0.76	$0.78	$0.89

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

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

Our revenues vary from year to year as a result of changes in realized commodity prices and production volumes. For more information, see “Source of our Revenues” above. In 2014, natural gas, NGLs and oil sales increased 11% from

2013 with a 24% increase in production partially offset by a 10% decrease in realized prices. In 2013, natural gas, NGLs and oil sales increased 27% from 2012 with a 25% increase in production and a 2% increase in realized prices. The following table illustrates the primary components of natural gas, NGLs, crude oil and condensate sales for each of the last three years (in thousands):

	2014	2013	2012
Natural gas, NGLs and Oil sales			
Gas wellhead	$1,140,989	$954,673	$612,354
Gas hedges realized	4,686	110,948	238,259
Total gas revenue	$1,145,675	$1,065,621	$850,613
Total NGLs revenue	$444,152	$315,272	$265,072
Oil and condensate wellhead	$316,625	$329,182	$237,963
Oil hedges realized	5,537	5,601	(1,954)
Total oil and condensate revenue	$322,162	$334,783	$236,009
Combined wellhead	$1,901,766	$1,599,127	$1,115,389
Combined hedges	10,223	116,549	236,305
Total natural gas, NGLs and oil sales	$1,911,989	$1,715,676	$1,351,694

Our production continues to grow through drilling success as we place new wells on production and through additions from acquisitions partially offset by the natural decline of our natural gas and oil reserves through production and asset sales. For 2014, our production volumes increased 30% in our Appalachian region and decreased 18% in our Midcontinent region when compared to 2013. For 2013, our production volumes increased 31% in our Appalachian region and decreased 4% in our Midcontinent region when compared to 2012. Our production for each of the last three years is set forth in the following table:

	2014	2013	2012
Production [(a)]			
Natural gas (mcf)	286,926,099	264,528,254	216,554,689
NGLs (bbls)	18,820,526	9,254,801	6,967,114
Crude oil and condensate (bbls)	4,069,568	3,827,491	2,851,312
Total (mcfe) [(b)]	424,266,663	343,022,006	275,465,245
Average daily production [(a)]			
Natural gas (mcf)	786,099	724,735	591,679
NGLs (bbls)	51,563	25,356	19,036
Crude oil and condensate (bbls)	11,150	10,486	7,790
Total (mcfe) [(b)]	1,162,374	939,786	752,637

(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 and natural gas, which is not indicative of the relationship of oil and natural gas prices.

Our average realized price (including all derivative settlements and third-party transportation costs) received during 2014 was $3.64 per mcfe compared to $4.16 per mcfe in 2013 and $4.35 per mcfe in 2012. Because we record transportation costs on two separate bases, as required by GAAP, we believe computed final realized prices should include the impact of transportation, gathering and compression expense. Our average realized price (including all derivative settlements and third-party transportation costs) calculation also includes all cash settlements for derivatives, whether or not they qualify for hedge accounting. Average sales prices (wellhead) do not include any derivative settlements or third party transportation costs which are reported in transportation, gathering and compression expense on the accompanying consolidated statements of income. Average sales prices (wellhead) do include transportation costs where we receive net proceeds. Average realized price calculations for each of the last three years are shown below:

	2014	2013	2012
Average Prices			
Average sales prices (wellhead):			
Natural gas (per mcf)	$3.98	$3.61	$2.83
NGLs (per bbl)	23.60	34.07	38.05
Crude oil (per bbl)	77.80	86.00	83.46
Total (per mcfe) [(a)]	4.48	4.66	4.05
Average realized prices (including derivative settlements that qualified for hedge accounting):			
Natural gas (per mcf)	$3.99	$4.03	$3.93
NGLs (per bbl)	23.60	34.07	38.05
Crude oil (per bbl)	79.16	87.47	82.77
Total (per mcfe) [(a)]	4.51	5.00	4.91
Average realized prices (including all derivative settlements):			