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.

	Acres		% of Total
As of December 31,	Gross	Net	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 numbe