

RANGE RESOURCES CORP
Form 10-K
February 25, 2016

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

(Mark one)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015

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
(State or Other Jurisdiction of Incorporation or Organization)

34-1312571
(IRS Employer Identification No.)

100 Throckmorton Street, Suite 1200, Fort Worth, Texas
(Address of Principal Executive Offices)

76102
(Zip Code)

Registrant's telephone number, including area code

(817) 870-2601

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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 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

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 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 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 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

The aggregate market value of the voting and non-voting common equity held by non-affiliates as of June 30, 2015 was \$8,138,124,000. 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 22, 2016, there were 169,585,625 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 2016 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 ("Securities Act") and Section 21E of the Securities Exchange Act of 1934, as amended ("Exchange Act"). These statements typically contain words such as "may," "anticipate," "believe," "estimate," "expect," "intend," "plan," "predict," "target," "project," "should," "would" or similar words, indicating that future 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.

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. 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."

Actual results may vary significantly from those anticipated due to many factors, including:

- natural gas, crude oil and natural gas liquids ("NGLs") prices;
- the availability and volatility of securities, capital or credit markets and the cost of capital to fund our operation and business strategy;
 - accuracy and fluctuations in our reserves estimates due to regulations or sustained low commodity prices;
- ability to develop existing reserves or acquire new reserves;
- changes in political or economic conditions in our key operating markets;
- prices and availability of goods and services;
- unforeseen hazards such as weather conditions, acts of war or terrorist acts;
- electronic, cyber or physical security breaches;
- the ability and willingness of current or potential lenders, derivative contract counterparties, customers and working interest owners to fulfill their obligations to us or to enter into transactions with us in the future on terms that are acceptable to us; or
- other factors discussed in Item 1 and 2. Business and Properties, Item 1A. Risk Factors, Item 7. Management Discussion and Analysis of Financial Condition and Results of Operations, Item 7A. Quantitative and Qualitative Disclosures about Market Risk and elsewhere in this report.

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 except as required by law.

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, NGLs and oil company, engaged in the exploration, development and acquisition of natural gas and oil properties, mostly focused in the Appalachian region of the United States. Our corporate offices are located at 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102 (telephone (817) 870-2601). We have a regional office in Canonsburg, Pennsylvania. Our common stock is listed and trades on the New York Stock Exchange (the “NYSE”) under the symbol “RRC.” At December 31, 2015, we had 169.4 million shares outstanding.

Our 2015 production had the following characteristics:

- average total production of 1,395.4 Mmcfe per day, an increase of 20% from 2014;
- 71% natural gas;
- total natural gas production of 362.7 Bcf, an increase of 26% from 2014;
- total NGLs production of 20.4 Mmbbls (including ethane), an increase of 8% from 2014;
- total crude oil and condensate production of 4.1 Mmbbls which was the same as 2014; and
- 86% of our total production was from the Marcellus Shale in Pennsylvania.

At year-end 2015, our proved reserves had the following characteristics:

- 9.9 Tcfe of proved reserves;
- 64% natural gas, 33% NGLs and 3% crude oil;
- 55% proved developed;
- 98% operated;
- 97% of proved reserves are in the Marcellus Shale in Pennsylvania;
- a reserve life index of approximately 19 years (based on fourth quarter 2015 production);
- a pretax present value of \$3.0 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 \$2.7 billion.

^(a)PV-10 is considered a non-GAAP financial measure as defined by the U.S. Securities and Exchange Commission (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 \$303.3 million at December 31, 2015.

Available Information

Our corporate 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 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 divestitures 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. We analyze and review performance while striving for continual improvement by working with peer companies, regulators, non-governmental organizations, industries not related to the oil and natural gas industry and other engaged stakeholders. 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 expect 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 primarily in one region: Pennsylvania. Concentrating our drilling and producing activities in a core area allows us to develop the regional expertise needed to interpret specific geological and operating conditions and develop economies of scale. Operating in a core area as large as the Marcellus Shale allows us to reach our goal of consistent production and reserve growth at attractive returns. We intend to further develop our acreage in the Marcellus Shale and improve our well results through the use of technology and detailed analysis of our properties. We periodically evaluate and pursue acquisition opportunities in the United States (including opportunities to acquire particular natural gas and oil properties or entities owning natural gas and oil assets) and at any given time we may be in various stages of evaluating such opportunities.

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 5,000 proven and unproven drilling locations in inventory. We actively seek to find and develop new natural gas and oil plays with significant exploration and exploitation potential.

Focus on Cost Efficiency. We concentrate in areas which we believe to have sizeable hydrocarbon deposits in place that will allow us to consistently increase production while controlling costs. Because 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 stockholder 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 cash

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flow and diversify risk. We hold numerous 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 optimizing 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 this in maintaining a strong balance sheet, ample liquidity and using commodity derivatives to help stabilize our realized prices. We believe provides more predictable cash flows and financial results. We regularly review our asset base to identify nonstrategic assets, the disposition of which will increase capital resources available for other activities and create organizational and operational efficiencies.

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, 2015, our employees and directors owned equity securities in our benefit plans (vested and unvested) that had an aggregate market value of approximately \$114 million.

Significant Accomplishments in 2015

Production growth – In 2015, our production averaged 1,395.4 Mmcfe per day, an increase of 20% from 2014. Drilling in the Marcellus Shale play in Pennsylvania drove our production growth. Our capital program is designed to allocate investments based on growth projects that produce the highest returns.

Proved reserves – Total proved reserves decreased 4% in 2015, from 10.3 Tcfe to 9.9 Tcfe. On a pro forma basis, adjusted for the sale of our Virginia and West Virginia assets, our proved reserves increased 6% in 2015, despite a reduced capital budget in 2015. This achievement is the result of continued drilling success, as all of our production and reserve growth in 2015, before asset sales, 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.

Low price environment initiatives – As a result of the significant drop in commodity prices, we took action to reduce capital spending, operating costs and general and administrative costs. We lowered our 2015 capital expenditure budget that was announced in December 2014 from \$1.3 billion to \$870 million. Other initiatives included the closing of our Oklahoma City divisional office in early 2015 and additional workforce reductions, which has continued into early 2016. In February 2016, the board of directors approved a reduction of our quarterly dividend from \$0.04 per share to \$0.02 per share.

Successful drilling program – In 2015, we drilled 152 gross natural gas and oil wells. We replaced 248% of our production through drilling in 2015 and our overall drilling success rate was 100%. 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.

Large resource potential – Maintaining an exposure to large potential resources is important. We continued expansion of our shale plays in 2015. We have three large unconventional and prospective plays – the Marcellus, Utica/Point Pleasant and Upper Devonian shales in Pennsylvania. These plays cover expansive areas, provide multi-year drilling opportunities, are in many cases stacked pay and, collectively, have sustainable lower risk growth profiles. The economics of these plays have been enhanced by continued advancements in drilling and completion technologies.

Focus on financial flexibility – We ended 2015 with less debt than year-end 2014. Debt per mcfe of proved reserves was \$0.27 at December 31, 2015 compared to \$0.30 at December 31, 2014. In May 2015, we issued \$750.0 million principal amount of 4.875% senior notes due 2025 and in July 2015, we redeemed all \$500.0 million aggregate principal amount of our 6.75% senior subordinated notes due 2020. As of December 31, 2015, we maintain a \$4.0

billion bank credit facility, with a borrowing base of \$3.0 billion and committed borrowing capacity was \$2.0 billion. As we have done historically, we may adjust our capital program, divest of non-strategic assets and use derivatives to protect a portion of our future production from commodity price volatility to ensure adequate funds to execute our drilling program and maintain liquidity.

Dispositions completed – In December 2015, we sold the majority of our Virginia and West Virginia assets for proceeds of \$876.0 million, before closing adjustments. We recognized a pretax loss of \$407.7 million. We also received \$14.9 million of additional proceeds during the year related to the sale of miscellaneous proved and unproved property and inventory.

Leasing acquisitions completed – In 2015, we leased or renewed \$73.0 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 27% and we continue to prove up acreage, acquire additional acreage and gain access to additional pipeline and processing capacity.

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Continued development of processing, pipeline takeaway capacity and marketing of NGLs – We continue our efforts 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 to transport ethane and propane from the tailgate of a third-party processing plant to a terminal and dock facility near Philadelphia (“Mariner East”). At the end 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. At the end of January 2016, startup of ethane operations was in process. We expect both propane and ethane operations on Mariner East to be fully functional by the end of first quarter 2016.

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 our 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, not including the impact of our derivative program.

Natural gas prices are primarily determined by North American supply and demand. The New York Mercantile Exchange (“NYMEX”) monthly settlement prices for natural gas averaged \$2.65 per mcf in 2015, with a high of \$3.19 per mcf in January and a low of \$2.03 per mcf in November. In 2014, monthly NYMEX settlement prices averaged \$4.37 per mcf. Since the end of 2015, natural gas prices have remained depressed, with the monthly settlement price for natural gas falling from \$2.21 per mcf in December 2015 to \$2.19 per mcf in February 2016. Natural gas prices continue to be under pressure largely due to excess supply of natural gas caused by the high productivity of shale plays in the United States which is outpacing demand. Demand for drilling rigs, oilfield supplies and drill pipe declines with falling commodity prices but such declines tend to lag behind the declines in natural gas and crude oil prices. Depressed natural gas prices continue to reflect the expectation there will be an oversupply of natural gas in 2016 and storage levels will remain higher than normal.

Significant factors that will impact 2016 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 \$49.21 per barrel in 2015, with a high of \$59.83 per barrel in June and a low of \$37.33 per barrel in December. In 2014, NYMEX monthly settlement oil averaged \$92.64 per barrel. Since the end of 2015, crude oil prices have declined significantly, with the monthly settlement price for crude oil falling from \$37.33 per barrel in December 2015 to \$31.78 per barrel in January 2016. The market oversupply of oil is expected to continue in 2016 with oil prices expected to remain under pressure.

NGLs prices are generally determined by North American supply and demand. We expect NGLs prices in 2016 to continue to be under pressure due to excess supply. The growth of unconventional drilling has substantially increased the supply of NGLs, which has caused a significant decline in NGL component prices. While more export facilities have been built and NGL exports are increasing along with the expansion of ethane cracking capacity, the overall United States demand for NGL products has not kept pace with supply of such products.

Natural gas, NGLs and oil prices affect:

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

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 are currently focused on both unconventional resource plays and conventional plays in Pennsylvania.

Outlook for 2016

For 2016, we have established a \$495.0 million capital budget for natural gas, NGLs, crude oil and condensate related activities, excluding proved property acquisitions, for which we do not budget. Of this amount, 98% is allocated to our Marcellus Shale operations. 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 2016 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 used 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 2016 is mitigated using commodity derivative contracts and we intend to continue to enter into these transactions. As a result of the significant drop in commodity prices, we have implemented initiatives to reduce capital spending, operating costs and administrative expenses to minimize spending in excess of cash flows. During 2015 and continuing into early 2016, we continue to work with our service providers to reduce costs. Also during 2015 and continuing into early 2016, we have implemented workforce reduction plans to reduce general operating expenses and we expect to continue to achieve savings from these initiatives into 2016. In February 2016, the board of directors approved a reduction of our quarterly dividend from \$0.04 per share to \$0.02 per share.

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,		
	2015	2014	2013
Production			
Natural gas (Mmcf)	362,687	286,926	264,528
Natural gas liquids (Mbbbls)	20,356	18,821	9,255
Crude oil and condensate (Mbbbls)	4,084	4,070	3,827
Total (Mmcfe) ^(a)	509,328	424,267	343,022
Average sales prices (excluding derivative settlements)			
Natural gas (per mcf)	\$2.13	\$3.98	\$3.61
Natural gas liquids (per bbl)	8.67	23.60	34.07
Crude oil and condensate (per bbl)	34.28	77.80	86.00
Total (per mcfe) ^(a)	2.14	4.48	4.66
Average realized prices (including derivatives settlements that qualified for hedge accounting):			
Natural gas (per mcf)	\$2.13	\$3.99	\$4.03
Natural gas liquids (per bbl)	8.67	23.60	34.07
Crude oil and condensate (per bbl)	34.28	79.16	87.47
Total (per mcfe) ^(a)	2.14	4.51	5.00
Average realized prices (including all derivatives settlements):			
Natural gas (per mcf)	\$3.07	\$3.79	\$4.00

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Natural gas liquids (per bbl)	10.73	24.31	32.71
Crude oil and condensate (per bbl)	71.28	79.75	84.70
Total (per mcfe) ^(a)	3.18	4.41	4.91
Average realized prices (including all derivative settlements and third party transportation costs)			
Natural gas (per mcf)	\$2.12	\$2.80	\$3.08
Natural gas liquids (per bbl)	8.12	22.04	31.29
Crude oil and condensate (per bbl)	71.28	79.75	84.70
Total (per mcfe) ^(a)	2.41	3.64	4.16
Direct operating costs			
Lease operating (per mcfe) ^(a)	\$0.25	\$0.31	\$0.34
Workovers (per mcfe) ^(a)	0.01	0.03	0.02
Stock-based compensation (per mcfe) ^(a)	0.01	0.01	0.01
Total (per mcfe) ^(a)	\$0.27	\$0.35	\$0.37

^(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 years ended 2015, 2014 and 2013 based on the average of prices on the first day of each month of the given calendar year, in accordance with 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			Total (Mmcfe) ^(a)	%
	Gas (Mmcf)	NGLs (Mbbls)	Oil (Mbbls)		
2015:					
Proved					
Developed	3,376,165	309,306	31,679	5,422,075	55 %
Undeveloped	2,901,533	239,828	21,514	4,469,588	45 %
Total Proved	6,277,698	549,134	53,193	9,891,663	100 %
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 %

^(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, 2015:

	Reserve Volumes				PV-10 ^(a)			
	Natural Gas (Mmcf)	NGLs (Mbbls)	Oil (Mbbls)	Total (Mmcfe)	%	Amount (In thousands)	%	
Appalachian Region	6,103,703	536,117	46,026	9,596,563	97 %	\$2,899,549	96 %	
Other	173,995	13,017	7,167	295,100	3 %	129,657	4 %	
Total	6,277,698	549,134	53,193	9,891,663	100 %	\$3,029,206	100 %	

- (a) PV-10 was prepared using the twelve-month average prices for 2015, 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 \$2.7 billion at December 31, 2015. The difference between the standardized measure and the PV-10 amount is the discounted estimated future income tax of \$303.3 million at December 31, 2015. Included in the \$3.0 billion pretax PV-10 is \$2.4 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 had Wright and Company, Inc., an independent petroleum consultant, conduct an audit of our year-end reserves. This engineering firm was selected for their geographic expertise and their historical experience in engineering certain properties. The proved reserve audits performed for 2015, 2014 and 2013, in the aggregate represented 94%, 96% and 96% of our proved reserves. The reserve audits performed for 2015, 2014 and 2013, in the aggregate represented 97%, 98% and 97% of our 2015, 2014 and 2013 associated pretax present value of proved reserves discounted at ten percent. Copies of the summary reserve report prepared by our independent petroleum consultant is included as an exhibit to this Annual Report on Form 10-K. The technical person at our 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 consultant 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 our independent petroleum consultant 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 consultant 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. Our consultant performs 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 pretax 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 our auditor and some may be less than the estimates of the reserve auditor. When such differences do not exceed 10% in the aggregate, our reserve auditor is satisfied that the proved reserves and pretax 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, Mr. Alan Farquharson, 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, 2015 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 that 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 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, 2015, NGLs represented approximately 33% 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 2015 averaged approximately 75% 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, 2015, we have 292.8 Mmbbls of ethane reserves (1,296 Bcfe) associated with our Marcellus Shale properties, which are included in NGLs proved reserves and represent 53% of our total NGLs reserves. We currently include ethane in our proved reserves which match volumes delivered under our existing long-term, extendable ethane contracts.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2015, our PUDs totaled 21.5 Mmbbls of crude oil, 239.8 Mmbbls of NGLs and 2.9 Tcfe of natural gas, for a total of 4.5 Tcfe. Costs incurred in 2015 relating to the development of PUDs were approximately \$398.8 million. Approximately 98% of our PUDs at year-end 2015 were associated with the Marcellus Shale. All PUD drilling locations are scheduled to be drilled prior to the end of 2020 with more than 78% 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 762.9 Bcfe of PUDs into proved developed reserves;

addition of new PUDs consisting of 915.7 Bcfe;

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441.9 Bcfe negative revision with 1.2 Tcfe of reserves reclassified to unproved because of reduced future capital spending due to lower commodity prices partially offset by improved recovery and other positive performance revisions of 725.6 Bcfe; and

201.8 Bcfe reduction from the sale of properties.

For an additional description of changes in PUDs for 2015, see Note 18 to our consolidated financial statements. We believe our PUDs reclassified to unproved can be included in our future proved reserves as these locations are added back into our five-year development plan.

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):

	2015	2014	2013	2012	2011
Future net cash flows	\$8,666	\$26,993	\$21,029	\$11,156	\$15,610
Present value:					
Before income tax	3,029	10,070	7,898	3,960	6,084
After income tax (Standardized Measure)	2,726	7,593	5,862	3,224	4,515
Benchmark prices (NYMEX):					
Gas price (per mcf)	2.59	4.35	3.67	2.76	4.12
Oil price (per bbl)	50.13	94.42	97.33	95.05	95.61
Wellhead prices:					
Gas price (per mcf)	2.07	4.14	3.75	2.75	3.55
Oil price (per bbl)	35.07	79.04	86.66	86.91	85.59
NGLs price (per bbl)	11.74	27.20	25.93	32.23	49.24

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). 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

Currently, our natural gas and oil operations are concentrated in the Appalachian region of the United States, primarily in the Marcellus Shale in Pennsylvania. Our properties consist of interests in developed and undeveloped natural gas and oil leases. 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.

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The table below summarizes our operating data for the year ended December 31, 2015.

Region	Average Daily Production (mcf per day)	Production (Mmcf)	Percentage of Production		Proved Reserves (Mmcf)	Percentage of Proved Reserves	
Appalachian	1,329,409	485,234	95	%	9,596,562	97	%
Other	66,010	24,094	5	%	295,101	3	%
Total	1,395,419	509,328	100	%	9,891,663	100	%

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The following table summarizes our costs incurred for the year ended December 31, 2015 (in thousands):

Region	Acreage Purchases	Development Costs	Exploration Costs	Gathering Facilities	Asset Retirement Obligations	Total
Appalachian	\$ 72,029	\$ 686,434	\$ 107,246	\$ 12,559	\$ 20,678	\$898,946
Other	996	21,834	1,665	778	1,506	26,779
Total costs incurred	\$ 73,025	\$ 708,268	\$ 108,911	\$ 13,337	\$ 22,184	\$925,725

Approximately 97% of our proved reserves at December 31, 2015 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, 2015, is our only field in which reserves are greater than 15% of our total proved reserves.

	Marcellus Shale		
	2015	2014	2013
Production:			
Natural gas (Mmcf)	301,721	224,034	203,926
NGLs (Mbbbls)	19,389	17,093	7,213
Crude oil and condensate (Mbbbls)	3,387	3,089	2,529
Total Mmcfe ^(a)	438,377	345,127	262,377
Sales Prices: ^(b)			
Natural gas (per mcf)	\$ 0.94	\$ 2.72	\$2.59
NGLs (per bbl)	5.66	20.32	33.19
Crude oil and condensate (per bbl)	31.78	73.77	82.11
Total (per mcfe)	1.14	3.43	3.72
Production Costs:			
Lease operating (per mcfe)	\$0.16	\$0.19	\$0.16
Production and ad valorem tax (per mcfe) ^(c)	0.05	0.08	0.11

^(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, predominantly in Pennsylvania. Currently, our reserves are primarily in the Marcellus Shale formation but also include the Utica/Point Pleasant, Medina and Upper Devonian formations which principally produce at depths ranging from 3,500 feet to 11,500 feet. We own 4,462 net producing wells, 99% of which we operate. Our average working interest in this region is 87%. As of December 31, 2015, we have approximately 1.0 million gross (905,000 net) acres under lease.

Reserves at December 31, 2015 were 9.6 Tcfe, a decrease of 298.1 Bcfe, or 3%, from 2014. Drilling additions (1.2 Tcfe), favorable reserve revisions for performance and improved recovery were more than offset by production, downward revisions for proved undeveloped reserves no longer in our current five year development plan (1.1 Tcfe), sales of 948.3 Bcfe and negative pricing revisions. Annual production increased 25% from 2014. During 2015, we spent \$793.7 million in this region to drill 123 (113.4 net) development wells and 19 (19.0 net) exploratory wells, all of which were productive. At December 31, 2015, the Appalachian region had an inventory of over 350 proven drilling locations and over 80 proven recompletions. During the year, the Appalachian region drilled 84 proven locations, added 85 new proven drilling locations and deleted 152 proven drilling locations with reserves reclassified to unproved because of lower future capital spending in response to lower commodity prices. 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 seven years. We had over 350 proven drilling locations at December 31, 2015. Our 2015 production from the Marcellus Shale increased 27% from 2014. During 2015, we drilled 111 (101.4 net) development wells and 19 (19.0 net) exploratory wells, all of which were successful. In 2016, we plan to drill over 65 net wells. During 2015, we had approximately 9 drilling rigs in the field and expect to run an average of 3 rigs throughout 2016.

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 purchase and transport ethane from the tailgate of a 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. At the end of January 2016, startup of ethane operations was in process. We expect both propane and ethane operations to be fully functional by the end of first quarter 2016. 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 agreement relating to ethane sales from the same terminal near Philadelphia which is expected to begin in early 2016.

Other

Our other operations include 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. We own 444 net producing wells in these locations, 96% of which we operate. Our average working interest is 74%. As of December 31, 2015, we have approximately 396,000 gross (308,000 net) acres under lease.

Total proved reserves decreased 120.5 Bcfe, or 29%, at December 31, 2015, when compared to year-end 2014. Drilling additions (31.5 Bcfe) were offset by production, property sales (15.1 Bcfe), negative performance revisions and downward revisions for proved undeveloped reserves no longer in our current five year development plan (61.7 Bcfe) and negative pricing revisions. Annual production volumes decreased 36% from 2014. During 2015, this region spent \$23.5 million to drill 10 (8.9 net) development wells, all of which were productive. During the year, the region achieved a 100% drilling success rate.

At December 31, 2015, this area had a development inventory of over 55 proven drilling locations and over 30 proven recompletions. During the year, this area drilled 4 proven locations, added 12 new proven locations and deleted 41 proven drilling locations. 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.

Divestitures

Over the last three years, we have divested over \$1.4 billion of non-strategic assets in order to increase capital resources available for other activities, reduce our unit cost structure, create organizational and operating efficiencies and increase financial flexibility through reduced debt levels. In 2015, we sold the following assets:

Virginia and West Virginia. On December 30, 2015, we closed the sale of the majority of our natural gas and oil properties and gathering assets in Virginia and West Virginia for cash proceeds of \$876.0 million, before closing adjustments. We used the proceeds from this sale to reduce the balance on our bank credit facility.

West Texas. In February 2015, we sold our remaining properties in West Texas for proceeds of \$10.5 million.

Miscellaneous. During the year ended December 31, 2015, we sold miscellaneous unproved property, inventory and other assets for proceeds of \$4.4 million.

Producing Wells

The following table sets forth information relating to productive wells at December 31, 2015. 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 Interest
	Gross	Net	
Natural gas	5,628	4,801	93%
Crude oil	113	105	85%
Total	5,741	4,906	85%

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, 2015, we were in the process of drilling 30 (28.0 net) wells.

	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Productive	133.0	122.3	228.0	215.7	178.0	171.9
Dry	$\frac{3}{4}$	$\frac{3}{4}$	1.0	1.0	1.0	1.0
Exploratory wells						
Productive	19.0	19.0	25.0			