2017 ANNUAL REPORT

RANGE RESOURCES®

DEAR FELLOW SHAREHOLDERS

As we look back over the past year, we saw much improved financial results in 2017 with increases in earnings, cash flow, revenues and production as compared to 2016. We saw revenues up by 137% with a net income of $333 million, compared to a loss of $521 million in 2016, while production increased by 30% as well. Operationally, the Marcellus continues to drive growth and profitability, with increasing capital efficiency. Outstanding drilling results during the year expanded the core inventory in all directions. After years of planning, our marketing strategy will be fully implemented in 2018 and is expected to improve our netback pricing going forward as Range accesses growing demand for natural gas and NGLs, particularly in the expanding export markets. We are slowing activity in North Louisiana following disappointing results in 2017, which will allow time for additional technical analysis that we expect will improve results in 2018.

In January, we released a five-year outlook designed to show what Range can accomplish over the next five years and beyond in terms of reducing debt and generating cash flow. As part of that outlook, Range expects annual production growth of approximately 11%, or close to 13% on a debt-adjusted per share basis, while generating roughly $1 billion of cumulative free cash flow at year-end 2017 strip pricing. Growing production at an estimated 11% and spending within cash flow at strip pricing provides a path to significantly reduce our leverage. Our expectation is that under this outlook, we will reach a net debt to EBITDAX ratio of approximately 3x by 2020, and below 2x by 2022—without assuming any asset sales. Any proceeds from our efforts to sell non-core assets can accelerate this deleveraging process. In the meantime, our hedging program supports near-term cash flow.

We also expect to improve our margins with greater access to better markets and continued improvement to the Company's cost structure through utilization of existing infrastructure and lower interest expense. Our five-year outlook assumes all production growth is from Range's Marcellus inventory, while North Louisiana production is assumed to remain steady from year-end 2018 through the remainder of the plan. Importantly, at the end of the five-year outlook, Range would still have over 3,200 locations in the core of the Marcellus alone. As our peers in the industry exhaust their core inventories over the next few years, we believe Range will be well-positioned with a long runway of high-quality drilling locations from which we can derive long-term value.

In our view, we have entered a new era of shale development where companies that have captured the most prolific resources have the ability to generate better returns for their shareholders. For Range, the flagship asset and growth driver of the Company will continue to be our large, high-quality, de-risked inventory in southwestern Pennsylvania. The quality of our assets allows Range to improve corporate returns and our leverage profile, while generating competitive growth of production and reserves on a debt-adjusted per share basis. And, of course, this will all be accomplished while maintaining our commitment to good stewardship of the environment and operating safely.

We also see several positives in the immediate term. In late 2017 and early 2018, two of three natural gas pipeline projects came on line, moving Marcellus gas from southwestern Pennsylvania to more favorable Gulf Coast markets. Enbridge's TETCO Adair Southwest project commenced service during the fourth quarter 2017 and TransCanada's Leach and Rayne Xpress project commenced full service in January 2018. In addition, Energy Transfer's Rover pipeline (phase 2) is expected to reach full completion in second quarter 2018, and is the last major natural gas transportation project for which Range has contracted for capacity. Once these projects are fully in service, approximately 90% of Range's 2018 gas price exposure is expected to be in favorable markets. Importantly, these upgrades to Range's transportation portfolio reduce basis volatility, especially during seasonally weak months, and should increase the predictability of Range's corporate natural gas basis differential going forward.

Notably, our natural gas basis differentials have already shown dramatic improvement over the last three years. In 2015, our differential was NYMEX minus 52 cents, which improved to minus 45 cents in 2016, and further improved to minus 32 cents in 2017. Our projection for 2018 is that our basis could improve to NYMEX minus 15 cents, which would reflect a significant year-over-year improvement. Along the same lines, our condensate differentials have also greatly improved, from WTI less $15 per barrel in 2015, to WTI less $9 per barrel in 2016, and WTI less $5 per barrel in 2017. Our 2018 projections have us at WTI less $5 to $6 per barrel. NGLs, which were 18% of WTI in 2015, are projected to be approximately 30% of WTI in 2018.

In 2017, our proved reserves increased 26% from the prior year to 15.3 Tcfe, with drill bit finding costs at an all-time company low of $0.31 per mcfe. Positive performance revisions also continued in 2017 as we extended lateral lengths, improved targeting and drove efficiencies throughout our developed leasehold and infrastructure. Future development costs for proven undeveloped locations are estimated to be $0.38 per mcfe, which should improve our top tier unhedged recycle ratio to approximately 3x. Importantly, Range added a record 3.5 Tcfe to proved reserves from extensions, discoveries and additions, driven primarily by our large inventory of low-risk, high-return projects in the Marcellus Shale.

Going forward, we expect to see continued capital efficiency gains. Our team hit a new milestone in 2017, drilling the longest Marcellus lateral in Pennsylvania and three of the top four longest laterals in the Marcellus. We anticipate driving down normalized well costs with longer laterals (estimated to average nearly 10,000 feet in the Marcellus in 2018), with approximately half of our 2018 wells on existing pads — and enhanced recoveries as a result of improved targeting and completions. We are achieving a significant increase in daily lateral footage drilled versus two years ago, and we've accomplished all of this while narrowing our lateral target window and drilling faster — enabling us to lower costs from 2016 on a per-foot basis by over 30%. As a result, we now have the most productive wells per thousand feet of lateral in the southwest portion of the Marcellus.

And while our new outlook focuses on the next five years, looking beyond that, in 2022 we will have the ability to hold production of 3.5 Bcfe per day flat for approximately $600 million per year of maintenance capital. This could give Range the ability to return more cash to shareholders in the form of increased dividends and/or share repurchases. Also, with 3,200 core Marcellus wells remaining post-2022, we would anticipate over 30 years of inventory holding production at 3.5 Bcfe per day. Finally, the size and quality of Range's remaining inventory, combined with improved access out of Southwest Appalachia, can provide Range with a growth option. Range could potentially generate annual growth of greater than 20% from 2023-2025 and generate over $1 billion of free cash flow over that time frame; all while the Lower Cotton Valley, Deep Utica, and Upper Devonian extend the runway for free cash flow generation and growth.

We are acutely aware that the Company's stock price is not where we'd like it to be. Although we had another year of success in the Marcellus, we didn't see the results we expected in North Louisiana. The asset has proven to be more geologically complex than originally anticipated, and productivity of the wells overall has been below our expectations. In response, we plan to allocate an estimated 15% of our capital to our North Louisiana operations in 2018, with 85% going toward the Marcellus. We have new leadership overseeing this division, and believe we have the right team in place to unlock the greatest potential for these assets.

As we take a final look back at 2017, I want to recognize our teams across the company for their commitment to safety and environmental compliance. Our safety record in 2017 included no days away from work and one recordable incident for the year. Our focus on further reducing methane emissions over the last several years led to Range being recognized in 2017 as a top performer in the area of emissions by the nonprofit organization As You Sow, as shown on our website here.

I also want to acknowledge Range's greatest asset: our employees. Once again in 2017, Range employees volunteered their time and talents to give back to those in need, all across the country. Our civic engagement programs are designed to have long-term sustainable positive impacts on organizations tied to our communities, and our corporate giving program has donated nearly $10 million to nonprofit and civic organizations in recent years. Last year, Range contributed $100,000 to the American Red Cross efforts in Houston, Texas after hurricane-related flooding, while employees pulled together to support neighbors in need. Employees also generated tens of thousands of dollars to support the community around the holidays by raising funds for area food banks and distributing toys for children in need throughout the Company's operating areas.

Our employees have always been the driving force behind the Company's success. Their continued commitment to innovation, social responsibility, and constantly seeking the answer to the question "how can we do this better?" is among the critical components that will propel us forward as we execute our five-year outlook. High-quality inventory and core locations that will produce for many years beyond those of most other companies, along with growing demand — particularly in the international markets — will also be key to fulfilling our expectations of creating greater value for our shareholders.

I want to thank our Board of Directors for their leadership year after year, and their guidance during the development of our strategy for long-term value creation and growth. We also congratulate the Board for having been recognized for diversity and good corporate governance by the nonprofit organization Women on Board.

And finally, we thank you, our loyal shareholders, for your continued faith in our company. We are in the midst of an American energy revolution that is providing our country with affordable energy, improved air quality, and greater economic prosperity. We are highly focused on continuing to earn your support, and appreciate your feedback as we work together toward a bright future for Range Resources.

Jeffrey L. Ventura

JEFFREY L. VENTURA
Chairman, President & Chief Executive Officer

RANGE BREAKS INDUSTRY RECORD FOR LONGEST LATERALS IN THE MARCELLUS SHALE

When Range Resources first began drilling horizontal wells in the Marcellus Shale, the average length of a lateral was around 2,500 feet. Today, the Company is routinely drilling laterals over 10,000 feet and has drilled as long as three miles in lateral length. In fact, in 2017, Range set a new record for the longest lateral drilled in the Marcellus.

Initially, the team wasn't aiming for a record, only for greater efficiency and the best use of resources. "This achievement demonstrates just how dedicated the team is to constant improvement," says Senior Vice President of Operations Dennis Degner. "We talk about being more efficient, we talk about capital discipline. This is a prime example of how, even while in a downturn, that dedication never faltered. In fact, it really sharpened the team even more, to reach levels well beyond what we'd reached in the past."

Horizontal drilling technology has been one of the most important factors for the modern shale boom. Lateral wellbores allow companies like Range to access larger volumes of natural gas with fewer wells and less disruption on the surface, while realizing significant cost savings.

Before breaking the current Marcellus Shale record, Range's longest laterals had come in around 11,000 feet, with the exception of one lateral that reached a length of 14,400 feet. Once they hit 15,000 feet in the first quarter of 2017, the team soon realized they'd broken an industry record.

And that number keeps growing. In 2018, the team has drilled laterals in excess of 18,000 feet.

For communities that benefit from natural gas drilling, longer laterals can mean more natural gas production from fewer locations. For Range, the practice allows for more strategic placement of pads, and the potential for fewer top holes: with the ability to drill longer laterals, there is more access to gas underground that previously would have required more vertical drilling from additional pads. Longer laterals can also add up to significant savings.

"Cost per lateral foot is a key performance indicator for us. And we've cut it drastically from where we were a few years ago," says Degner. "For us to now drill laterals that are a three-fold increase from where we were just a few years ago, is remarkable. It exemplifies the creativity that the team has been able to deliver—minimizing our environmental footprint, increasing efficiencies, and being responsible with our dollars."

CEO Jeff Ventura explained the team's accomplishments:

"We drilled 1.1 million lateral feet in 2017, which represents a new record and is a 30% increase in the footage drilled per rig over the prior year. The team has now drilled our top 15 longest Marcellus lateral lengths in 2017, with several laterals planned for 17,000 to over 18,000 feet in 2018. In fact, we recently set pipe on a 17,875-foot Marcellus lateral and the rig will be drilling a planned 18,100-foot lateral on the same pad.

"Our internal industry research shows that we've now drilled the longest Marcellus lateral on record. While the average lateral length drilled in 2017 increased by 34%, importantly the drilling costs per foot decreased by 16%.

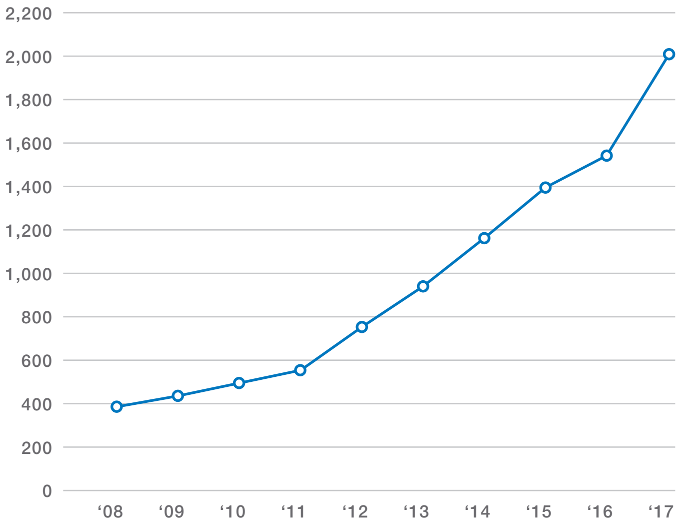
"These drilling efficiencies have served to offset some of the increased service costs we've seen. This is reflected in our well economics that show improvement on a normalized cost basis in 2018."

Range is proud of the Appalachia team's record-setting achievements, and their continued focus on innovation and new technology to further improve operations and efficiencies.

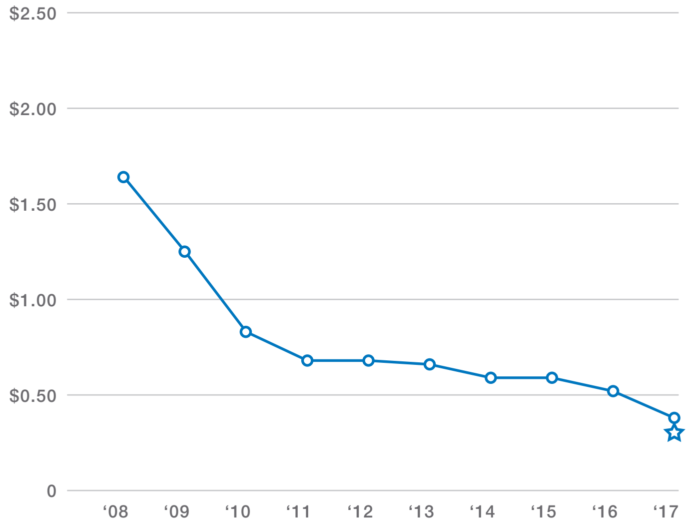
"This is an example of how success begets success," says Degner. "It's a true example of the strength of the teamwork in Appalachia. And they are continuing to push the envelope every quarter, to define what that next level of success will look like."

RANGE RESOURCES CORPORATION - PRODUCTION & RESERVES HISTORY

PRODUCTION
(Mmcfe per day)

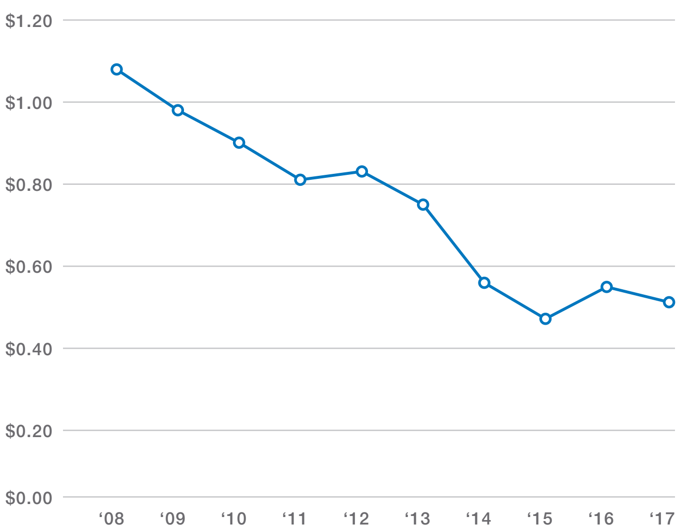


3 YEAR AVERAGE DRILL BIT FINDING COSTS
(Dollars per Mcfe)

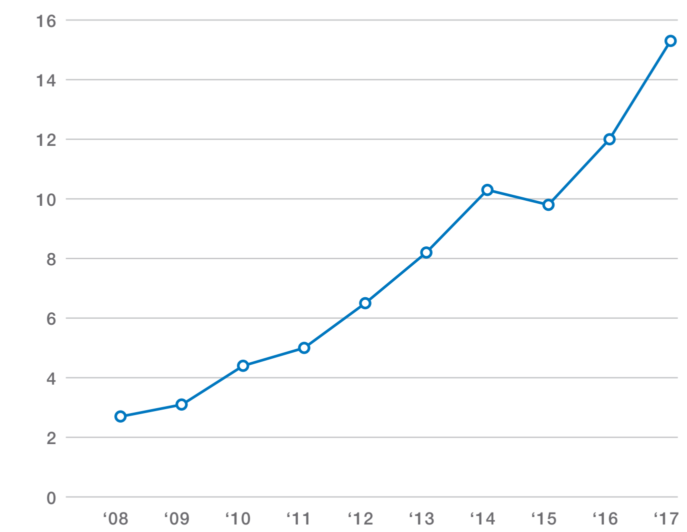


Includes performance revisions, Excludes acreage cost.
☆ 2017 only = $0.31

DEBT/PROVED DEVELOPED RESERVES
(Dollars per Mcfe)



PROVED RESERVES
(Tcfe)



RANGE RESOURCES CORPORATION

Range is a leading independent natural gas, NGL and oil producer with operations focused in stacked-pay projects in the Appalachian Basin and North Louisiana. As of December 31, 2017, Range had 15.3 Tcfe of proved reserves, a 26% increase over the prior year. In addition, Range estimates 58 Tcfe in net unrisked resource potential from the Marcellus, which does not include Utica and Upper Devonian formations. Range's common stock is listed on the New York Stock Exchange under the symbol "RRC." More information about Range can be found at www.rangeresources.com.

CORPORATE INFORMATION

BOARD OF DIRECTORS

BRENDA A. CLINE [1,4]	Executive Vice President, Chief Financial Officer, Treasurer & Secretary of Kimball Art Foundation
ANTHONY V. DUB [1,2]	Chairman, Indigo Capital, LLC
ALLEN FINKELSON [4]	Retired Partner, Cravath, Swaine & Moore LLP
JAMES M. FUNK [5,2,3]	President, J.M. Funk & Associates, past President of Shell Oil Co. and Equitable Production Co.
CHRISTOPHER A. HELMS [2]	Founder and CEO, US Shale Energy Advisors LLC, past Executive Vice President & Group CEO, NiSource, Inc.
ROBERT A. INNAMORATI [1]	President, Robert A. Innamorati & Co., past board member of Memorial Resource Development Corp.
MARY RALPH LOWE [4]	President & CEO, Maralo, LLC
GREG G. MAXWELL [1,2]	Retired EVP, Finance & CFO of Phillips 66
KEVIN S. McCARTHY [4]	Chairman, Chief Executive Officer & President, Kayne Anderson MLP
STEFFEN E. PALKO [2]	Associate Professor – Texas Christian University, Co-founder, past President and Vice - Chairman of XTO Energy, Inc.
JEFFREY L. VENTURA [3]	Chairman, President & Chief Executive Officer, Range Resources Corporation

SENIOR MANAGEMENT

JEFFREY L. VENTURA	Chairman, President & Chief Executive Officer
ROGER S. MANNY	Executive Vice President – Chief Financial Officer
RAY N. WALKER, JR.	Executive Vice President – Chief Operating Officer
DENNIS L. DEGNER	Senior Vice President – Operations
ALAN W. FARQUHARSON	Senior Vice President – Reservoir Engineering & Economics
DORI A. GINN	Senior Vice President – Controller & Principal Accounting Officer
DAVID P. POOLE	Senior Vice President – General Counsel & Corporate Secretary
CHAD L. STEPHENS	Senior Vice President – Corporate Development

Board Committee Membership: [1] Audit, [2] Compensation, [3] Dividend, [4] Governance and Nominating, [5] Lead Independent Director

FORM 10-K

Additional printed copies of the Company's Annual Report on Form 10-K filed with the Securities and Exchange Commission may be obtained upon request from Investor Relations at our headquarters' address.

Inquiries about the Company should be directed to:

INVESTOR RELATIONS
RANGE RESOURCES CORPORATION
100 THROCKMORTON ST., SUITE 1200
FORT WORTH, TX 76102
817-870-2601
817-869-9166 (FAX)

TRANSFER AGENT

For assistance regarding a change of address or concerning your stock account, please contact:

COMPUTERSHARE, INC.
P.O. BOX 30170
COLLEGE STATION, TX 77842-3170
877-581-5548
HTTPS://WWW-US.COMPUTERSHARE.COM/INVESTOR/CONTACT

Use our web site to obtain the latest news releases and SEC filings: WWW.RANGERESOURCES.COM

In addition to historical information, this report contains forward-looking statements that may vary materially from actual results. Factors that could cause actual results to differ are included in the Company's Form 10-K for the year ended December 31, 2017, which has been filed with the Securities and Exchange Commission.

FORM 10-K

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, 2017

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 ☒ 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	☐
		Smaller reporting company	☐
Non-accelerated filer	☐ (Do not check if a smaller reporting company)	Emerging growth company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act: ☐

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, 2017 was $5,683,957,000. 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, 2018, there were 248,539,169 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 2018 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. 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 Items 1 & 2. Business and Properties of this report.

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Disclosures Regarding Forward-Looking Statements

This Annual Report on Form 10-K, contains 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 are statements, other than statements of historical fact, that give current expectations or forecasts of future events, including without limitation: drilling plans, planned wells, rig count; our 2018 capital budget and the planned allocation thereof; reserve estimates; expectations regarding future economic and market conditions and their effects on us; and our ability to manage through the lower commodity cycles. These statements typically contain words such as "may," "anticipates," "believes," "estimates," "expects," "plans," "predicts," "targets," "projects," "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.

While we believe 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 other factors discussed in Item 1A. Risk Factors.

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

- conditions in the oil and gas industry, including pricing and supply/demand levels for natural gas, crude oil and natural gas liquids ("NGLs");
- 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, reservoir performance or sustained low commodity prices;
- ability to develop existing reserves or acquire new reserves;
- well production timing;
- 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;
- other geological, operating and economic considerations;
- 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 Items 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. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements contained throughout this report.

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 in the United States. Our principal areas of operation are the Marcellus Shale in Pennsylvania and the Lower Cotton Valley formation in Louisiana. 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 trades on the New York Stock Exchange (the "NYSE") under the ticker symbol "RRC". We have been a member of the S&P 500 Index since 2007. Range Resources Corporation was incorporated in 1980. At December 31, 2017, we had 248 million shares outstanding.

Our 2017 production had the following characteristics:

- average total production of 2,008.9 Mmcfe per day, an increase of 30% from 2016;
- 67% natural gas;
- total natural gas production of 490.3 Bcf, an increase of 30% from 2016;
- total NGLs production of 35.7 Mmbbls (including ethane), an increase of 28% from 2016;
- total crude oil and condensate production of 4.8 Mmbbls, an increase of 33% from 2016; and
- 79% of our total production was from the Marcellus Shale play in Pennsylvania.

At year-end 2017, our proved reserves had the following characteristics:

- 15.3 Tcfe of proved reserves;
- 67% natural gas, 30% NGLs and 3% crude oil;
- 55% proved developed;
- 100% operated;
- 91% of proved reserves are in the Marcellus Shale in Pennsylvania;
- a reserve life index of approximately 19 years (based on fourth quarter 2017 production);
- a pretax present value of $8.1 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 $7.2 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 the discounted estimated future income tax of $982.0 million at December 31, 2017.

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 responsibility culture, 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 returns − focused growth, on a per share debt-adjusted basis, of both reserves and production. Our strategy to achieve our business objective is to increase reserves and production through internally generated drilling projects coupled with occasional acquisitions and divestitures of non-core assets. In addition, we expect to limit capital spending to at or below cash flow. 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.

These elements are primarily anchored by our interests in the Marcellus Shale located in Pennsylvania. Complementing this growth area, we have natural gas, crude oil and condensate and NGLs production activities in the Lower Cotton Valley in North Louisiana.

Commit to Environmental Protection and Worker and Community Safety. We strive to implement technologies and 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 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 two regions: Pennsylvania and North Louisiana. 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 as large as the Marcellus Shale and the Lower Cotton Valley allows us to pursue our goal of consistent production and reserve growth at attractive returns. We intend to further develop our acreage in both the Marcellus Shale and North Louisiana 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 4,400 proven and unproven drilling locations in inventory.

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.

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 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 in maintaining ample liquidity, using commodity derivatives to help stabilize our realized prices and focusing on financial discipline. We believe this 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, 2017, our employees and directors owned equity securities in our benefit plans (vested and unvested) that had an aggregate market value of approximately $100 million.

Significant Accomplishments in 2017

- ***Production growth*** – In 2017, our production averaged 2,008.9 Mmcfe per day, an increase of 30% from 2016. Drilling in the Marcellus Shale play in Pennsylvania drove our production growth. In addition, our merger with Memorial Resource Development Corp. ("Memorial" or "MRD Merger") in September 2016 also positively impacted our 2017 production. Our capital program is designed to allocate investments based on projects that maximize our production and reserve growth at attractive returns, while minimizing controllable costs associated with production activities.
- ***Proved reserves*** – Total proved reserves increased 26% in 2017, from 12.1 Tcfe to 15.3 Tcfe. This achievement is the result of continued drilling success. The Marcellus Shale is our largest producing region and contains our greatest concentration of reserves. 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 2017, we drilled 177 gross natural gas and oil wells. We replaced 476% of our production through drilling in 2017 and our overall drilling success rate approached 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. Controlling the costs to find, develop and produce natural gas, NGLs and oil is critical in creating long-term stockholder value. Our focus areas are characterized by large, contiguous acreage positions and multiple stacked geologic horizons. In 2017, we continued to reduce average well costs per foot drilled through faster drilling times, longer laterals and innovative completion optimizations.
- ***Large resource potential*** – Maintaining an exposure to large potential resources is important. We continued expansion of our shale plays in 2017. We have three large unconventional and prospective plays in Pennsylvania: the Marcellus, Utica and Upper Devonian shales. These plays cover expansive areas, provide multi-year drilling opportunities, are in many cases stacked pay and, collectively, have sustainable lower risk growth profiles. Our activity in North Louisiana targets four of the stacked over-pressured pay zones in the Lower Cotton Valley formation.
- ***Focus on financial flexibility*** – As of December 31, 2017, we maintained a $4.0 billion bank credit facility, with a borrowing base of $3.0 billion and committed borrowing capacity of $2.0 billion. We endeavor to maintain a strong liquidity position. 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*** – During 2017, we completed several divestitures. In first quarter 2017, we sold certain properties in Western Oklahoma for proceeds of $26.0 million and we recorded a gain of $22.1 million related to this sale, after closing adjustments and transaction fees. In fourth quarter 2017, we sold certain properties in the Texas Panhandle and Oklahoma for proceeds of $44.4 million and we recorded a loss of $28,000 related to these sales.
- ***Leasing acquisitions completed*** – In 2017, we leased or renewed $62.1 million of acreage located in our core areas. We continue to see outstanding results in the Marcellus Shale. Production in the Marcellus Shale increased 16% and we continue to prove up acreage, acquire additional acreage and gain access to additional pipeline and processing capacity.

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 and to a lesser extent, natural gas exports and are heavily influenced by weather and storage levels. The New York Mercantile Exchange (“NYMEX”) monthly settlement prices for natural gas averaged $3.10 per mcf in 2017, with a high of $3.93 per mcf in January and a low of $2.63 per mcf in March. In 2016, monthly NYMEX settlement prices averaged $2.51 per mcf. Since the end of 2017, natural gas prices have increased, with the monthly settlement price for natural gas increasing from $3.07 per mcf in December 2017 to $3.63 per mcf in February 2018. Natural gas prices may 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 has outpaced demand. Depressed natural gas futures prices reflect the expectation there will be an oversupply of natural gas in the future.

Significant factors that will impact 2018 crude oil prices include worldwide economic conditions, political and economic developments in the Middle East, Africa and South America, 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 $51.07 per barrel in 2017, with a high of $57.95 per barrel in December and a low of $45.20 per barrel in June. In 2016, NYMEX monthly settlement oil averaged $43.69 per barrel. Since the end of 2017, crude oil prices have improved, with the monthly settlement price for crude oil rising from $57.95 per barrel in December 2017 to $63.66 per barrel in January 2018. The likelihood of a sustained recovery in worldwide demand for energy is difficult to predict. As a result, we expect crude oil commodity prices will continue to be volatile in 2018.

NGLs prices are primarily determined by North American supply and demand and to a lesser extent, international supply and demand. The growth of unconventional drilling has substantially increased the supply of NGLs, which until recently, caused a significant decline in NGLs component prices. Additional export facilities have been built and NGLs exports are increasing along with the expansion of ethane cracking capacity which has recently improved NGLs pricing in the United States. While NGLs component prices have improved in recent months, we expect prices will continue to be volatile in 2018.

Natural gas, NGLs and oil prices affect:

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

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

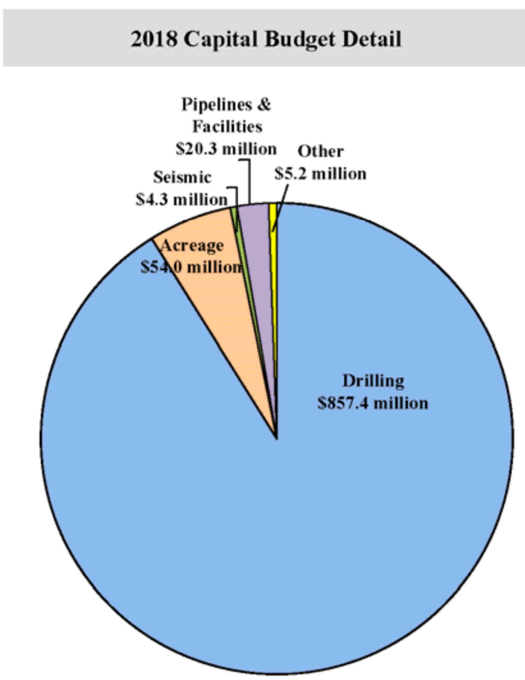
Our operations consist of one reportable segment. We have a single, company-wide management team that administers all properties as a whole rather than by discrete operating segments. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis. Our exploration and production operations are limited to onshore United States.

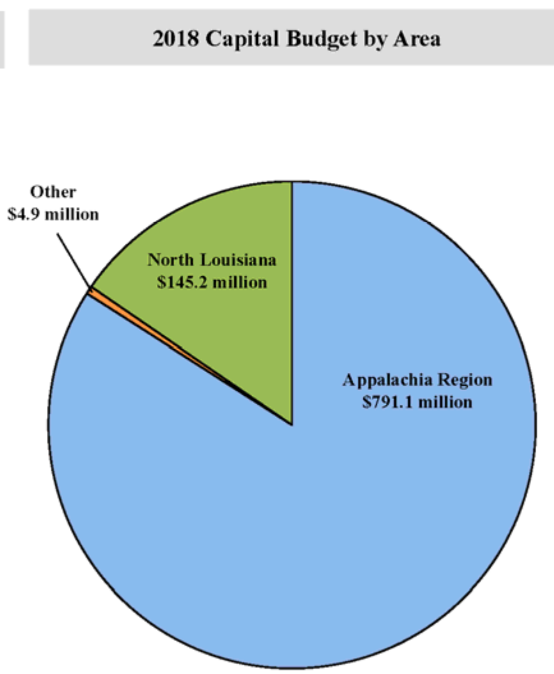
Outlook for 2018

For 2018, we have established a $941.2 million capital budget for natural gas, NGLs, crude oil and condensate related activities, excluding proved property acquisitions, for which we do not budget. As has been our historical practice, we will periodically review our capital expenditures throughout the year and may adjust the budget based on commodity prices, drilling success and other factors. Throughout the year, we allocate capital on a project-by-project basis, across our entire asset base to optimize returns without regard to individual areas. To the extent our 2018 capital requirements exceed our internally generated cash flow, proceeds from asset sales, drawing on our committed capacity under our bank credit facility, and/or debt or equity financing 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 2018 is mitigated using commodity derivative contracts and we intend to continue to enter into these transactions.

Our primary near-term focus includes:

- preserve liquidity and improve financial strength;
- focus on organic opportunities through disciplined capital investments;
- high-grade investments based on rates of returns;
- improve operational efficiencies and economic returns;
- limit capital spending to at or below cash flow; and
- attract and retain quality employees whose efforts are aligned with stockholders' interests.





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,		
	2017	2016	2015
Production			
Natural gas (Mmcf)	490,253	375,811	362,687
Natural gas liquids (Mbbls)	35,709	27,826	20,356
Crude oil and condensate (Mbbls)	4,787	3,609	4,084
Total (Mmcfe) [(a)]	733,231	564,420	509,328
Average sales prices (excluding derivative settlements)			
Natural gas (per mcf)	$ 2.75	$ 2.01	$ 2.13
Natural gas liquids (per bbl)	16.93	11.44	8.67
Crude oil and condensate (per bbl)	46.30	34.60	34.28
Total (per mcfe) [(a)]	2.97	2.12	2.14
Average realized prices (including all derivative settlements):			
Natural gas (per mcf)	$ 2.90	$ 2.68	$ 3.07
Natural gas liquids (per bbl)	14.88	13.16	10.73
Crude oil and condensate (per bbl)	49.49	47.82	71.28
Total (per mcfe) [(a)]	2.99	2.74	3.18
Average realized prices (including all derivative settlements and third party transportation costs)			
Natural gas (per mcf)	$ 1.82	$ 1.60	$ 2.12
Natural gas liquids (per bbl)	8.32	7.33	8.12
Crude oil and condensate (per bbl)	49.49	47.82	71.28
Total (per mcfe) [(a)]	1.95	1.74	2.41
Direct operating costs			
Lease operating (per mcfe) [(a)]	$ 0.17	$ 0.16	$ 0.25
Workovers (per mcfe) [(a)]	0.01	0.01	0.01
Stock-based compensation (per mcfe) [(a)]	—	—	0.01
Total (per mcfe) [(a)]	$ 0.18	$ 0.17	$ 0.27

[(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 2017, 2016 and 2015 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 Gas (Mmcf)	NGLs (Mbbls)	Oil (Mbbls)	Total (Mmcfe) [a]	%
2017:					
Proved					
Developed	5,437,674	448,258	36,808	8,348,074	55%
Undeveloped	4,825,975	315,006	33,046	6,914,287	45%
Total Proved	10,263,649	763,264	69,854	15,262,361	100%
2016:					
Proved					
Developed	4,352,141	363,852	39,110	6,769,908	56%
Undeveloped	3,518,275	266,214	31,143	5,302,414	44%
Total Proved	7,870,416	630,066	70,253	12,072,322	100%
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%

(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, 2017:

	Reserve Volumes					PV-10 [a]	
	Natural Gas (Mmcf)	NGLs (Mbbls)	Oil (Mbbls)	Total (Mmcfe)	%	Amount (In thousands)	%
Appalachian Region	9,336,478	704,202	55,855	13,896,819	91%	$ 7,079,971	87%
North Louisiana Region	877,226	50,836	10,270	1,243,863	8%	1,008,553	12%
Other	49,945	8,226	3,729	121,679	1%	58,722	1%
Total	10,263,649	763,264	69,854	15,262,361	100%	$ 8,147,246	100%

(a) PV-10 was prepared using the twelve-month average prices for 2017, 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 $7.2 billion at December 31, 2017. The difference between the standardized measure and the PV-10 amount is the discounted estimated future income tax of $982.0 million at December 31, 2017. Included in the $8.1 billion pretax PV-10 is $5.5 billion related to proved developed reserves.

Reserve Estimation

All reserve information in this report is based on estimates prepared by our petroleum engineering staff and is the responsibility of management. We also have the following independent petroleum consultants conduct an audit of our year-end 2017 reserves: Wright & Company, Inc. (Appalachia) and Netherland, Sewell & Associates, Inc. (North Louisiana). The purpose of these audits was to provide additional assurance on the reasonableness of internally prepared reserve estimates. These engineering firms were selected for their geographic expertise and their historical experience in engineering certain properties. The proved reserve audits performed for 2017, 2016 and 2015, in the aggregate represented 98%, 96% and 94% of our proved reserves. The reserve audits performed for 2017, 2016 and 2015, in the aggregate represented 98%, 96% and 97% of our 2017, 2016 and 2015 associated pretax present value of proved reserves discounted at ten percent. Copies of the summary reserve reports prepared by our 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 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. Our 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 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 auditors. When such differences do not exceed 10% in the aggregate, our reserve auditors are 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, 2017 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, NGLs 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, decline curve analysis, well logs, geologic maps and available downhole and production data, seismic data, well test data, reservoir simulation modeling and implementation and application of enhanced data analytics.

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, 2017, 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 2017 averaged approximately 63% 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, 2017, we have 360.6 Mmbbls of ethane reserves (1,596 Bcfe) associated with our Marcellus Shale properties, which are included in NGLs proved reserves and represent 48% of our total NGLs reserves. We currently include ethane in our proved reserves which match volumes to be delivered under our existing long-term, extendable ethane contracts.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2017, our PUDs totaled 33.0 Mmbbls of crude oil, 315.0 Mmbbls of NGLs and 4.8 Tcf of natural gas, for a total of 6.9 Tcfe. Costs incurred in 2017 relating to the development of PUDs were approximately $920.0 million. Approximately 93% of our PUDs at year-end 2017 were associated with the Marcellus Shale. All PUD drilling locations are scheduled to be drilled prior to the end of 2022 with more than 76% of the future development costs expected to be spent in the next three years. As of December 31, 2017, we have 64 Bcfe of reserves that have been reported for more than five years from their original booking, all of which are in the process of being drilled. Changes in PUDs that occurred during the year were due to:

- conversion of approximately 1.9 Tcfe of PUDs into proved developed reserves;
- addition of new PUDs from drilling consisting of 3.2 Tcfe;
- 308.9 Bcfe net positive revision with 668.3 Bcfe of reserves reclassified to unproved because of previously planned wells not to be drilled within the original five-year development horizon offset by improved recovery and other positive performance revisions of 977.2 Bcfe; and
- 9 Bcfe reduction from the sale of properties.

For an additional description of changes in PUDs for 2017, 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):

	2017	2016	2015	2014	2013
Future net cash flows	$ 21,469	$ 10,301	$ 8,666	$ 26,993	$ 21,029
Present value:					
Before income tax	8,147	3,727	3,029	10,070	7,898
After income tax (Standardized Measure)	7,165	3,452	2,726	7,593	5,862
Benchmark prices (NYMEX):					
Gas price (per mcf)	2.98	2.48	2.59	4.35	3.67
Oil price (per bbl)	51.19	42.68	50.13	94.42	97.33
Wellhead prices:					
Gas price (per mcf)	2.60	2.07	2.07	4.14	3.75
Oil price (per bbl)	45.73	37.41	35.07	79.04	86.66
NGLs price (per bbl)	17.84	13.44	11.74	27.20	25.93

Future net cash flows represent projected revenues from the sale of proved reserves, net of production and development costs (including transportation and gathering expenses, 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 and North Louisiana regions of the United States, primarily in the Marcellus Shale in Pennsylvania and the Lower Cotton Valley formation in Louisiana. Our North Louisiana properties were acquired in September 2016. 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. The table below summarizes our operating data for the year ended December 31, 2017. During December 2017, certain properties included in our “Other” operational region were sold.

Region	Average Daily Production (mcfe per day)	Production (Mmcfe)	Percentage of Production	Proved Reserves (Mmcfe)	Percentage of Proved Reserves
Appalachian	1,600,566	584,207	80%	13,896,819	91%
North Louisiana	379,982	138,693	19%	1,243,863	8%
Other	28,304	10,331	1%	121,679	1%
Total	2,008,852	733,231	100%	15,262,361	100%

The following table summarizes our costs incurred for the year ended December 31, 2017 (in thousands):

Region	Acreage Purchases	Acquisitions	Development Costs	Exploration Costs	Gathering Facilities	Asset Retirement Obligations	Total
Appalachian	$ 37,396	$ —	$ 719,479	$ 30,382	$ 8,067	$ 8,162	$ 803,486
North Louisiana	24,635	18,269	453,800	16,113	7,052	11,236	531,105
Other	44	—	4,247	9,197	(22)	847	14,313
Total costs incurred	$ 62,075	$ 18,269	$ 1,177,526	$ 55,692	$ 15,097	$ 20,245	$ 1,348,904

Approximately 91% of our proved reserves at December 31, 2017 is located in the Marcellus Shale in our Appalachian region. This play has a large portfolio of drilling opportunities and therefore has a significant unbooked resource potential within the Marcellus, Utica and Upper Devonian formations. The following table below sets forth annual production volumes, average sales prices and production cost data for our wells in the Marcellus Shale play which, as of December 31, 2017, is our only field in which reserves are greater than 15% of our total proved reserves.

	Marcellus Shale		
	2017	2016	2015
Production:			
Natural gas (Mmcf)	377,096	327,000	301,721
NGLs (Mbbls)	29,972	25,666	19,389
Crude oil and condensate (Mbbls)	3,407	2,783	3,387
Total Mmcfe [(a)]	577,368	497,697	438,377
Sales Prices: [(b)]			
Natural gas (per mcf)	$ 1.55	$ 0.79	$ 0.94
NGLs (per bbl)	9.70	5.00	5.66
Crude oil and condensate (per bbl)	45.49	32.24	31.78
Total (per mcfe)	1.79	0.96	1.14
Production Costs:			
Lease operating (per mcfe)	$ 0.10	$ 0.11	$ 0.16
Production and ad valorem tax (per mcfe) [(c)]	0.05	0.05	0.05

(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, Medina and Upper Devonian formations which principally produce at depths ranging from 3,500 feet to 11,500 feet. We own 4,554 net producing wells, 100% of which we operate. Our average working interest in this region is 89%. As of December 31, 2017, we have approximately 945,000 gross (881,000 net) acres under lease.

Reserves at December 31, 2017 were 13.9 Tcfe, an increase of 3.3 Tcfe, or 32%, from 2016. Drilling additions of 3.2 Tcfe and favorable reserve revisions for performance, improved recovery and positive pricing revisions were partially offset by production, downward revisions for proved undeveloped reserves no longer in our current five year development plan of 652.6 Bcfe and sales of

6.6 Bcfe. Annual production increased 16% from 2016. During 2017, we spent $721.5 million in this region to drill 110 (107.2 net) development wells, all of which were productive. At December 31, 2017, the Appalachian region had an inventory of over 349 proven drilling locations and 2 proven recompletions. During the year, the Appalachian region drilled 95 proven locations, added 208 new proven drilling locations and deleted or sold 64 proven drilling locations with deleted 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 nine years and we continue to pursue initiatives to improve drilling and completion efficiencies and reduce costs. We had over 349 proven drilling locations at December 31, 2017. Our 2017 production from the Marcellus Shale increased 16% from 2016. During 2017, we drilled 110 (107.2 net) development wells and no exploratory wells, all of which were successful. In 2018, we plan to drill approximately 100 net wells. During 2017, we had approximately 7 drilling rigs in the field and expect to run an average of 5 rigs throughout 2018.

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 NGL fractionation. We have an ethane sales contract in southwestern Pennsylvania whereby a third party purchases and transports ethane from the tailgate of third-party processing and fractionation facilities to the international border for further deliveries into Canada. We also have agreements to transport ethane to the Gulf Coast.

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 for sale to domestic and international customers. Also in 2012, we executed a fifteen year agreement relating to ethane sales from that same terminal near Philadelphia. Propane and ethane operations from the terminal began in early 2016.

North Louisiana

We began operations in North Louisiana in September 2016 as a result of the MRD Merger. These operations are focused on over-pressured natural gas opportunities in multiple zones in the Lower Cotton Valley formation. The Lower Cotton Valley formation extends across East Texas, Louisiana and Southern Arkansas. The formation has been under development since the 1930s and is characterized by thick, multi-zone natural gas and oil reservoirs with well-known geologic characteristics and long-lived, predictable production profiles. We own 415 net producing wells in these locations, 100% of which we operate. Our average working interest is 72%. As of December 31, 2017, we have approximately 233,000 gross (205,000 net) acres under lease.

Total proved reserves were 1.2 Tcfe at December 31, 2017, a decrease of 3% from 2016. At December 31, 2017, this area had a development inventory of over 50 proven drilling locations and over 40 proven recompletions. We spent $453.8 million in this region to drill 63 (53.2 net) development wells, all of which were productive. In 2018, we plan to drill approximately 10 net wells. Our operational focus in the Lower Cotton Valley will be on a horizontal development drilling program and continued testing of defined extension areas. We expect our redevelopment program to target four of the stacked over-pressured pay zones in the Lower Cotton Valley formation − zones we term the Upper Red, Lower Red, Lower Deep Pink and Upper Deep Pink. These four zones have an overall thickness ranging from 525 to 1,800 feet. In 2017, we had approximately 5 drilling rigs in the field and we expect to run an average of one rig throughout 2018.

We have long-term agreements with third parties to provide gathering, processing and transportation services and infrastructure assets in North Louisiana. We have entered into an area of mutual interest and exclusivity agreement with one of these parties whereby they have the exclusive right to provide midstream services to support our current and future production within such area.

Other

Our other operations include drilling, production and field operations in the Nemaha Uplift of Northern Oklahoma. We own 151 net producing wells in these locations, 100% of which we operate. Our average working interest is 95%. As of December 31, 2017, we have approximately 195,000 gross (121,000 net) acres under lease.

Total proved reserves decreased 101.3 Bcfe, or 45%, at December 31, 2017 when compared to year-end 2016. Reserves declined due to production, property sales (74.6 Bcfe), downward revisions for proved undeveloped reserves no longer in our current five year development plan (15.6 Bcfe) partially offset by positive pricing revisions. Annual production volumes decreased 32% from 2016.

At December 31, 2017, this area had a development inventory of over 25 proven drilling locations and over 5 proven recompletions. During the year, this area had 1 (1.0 net) exploratory well which was not productive. Development projects include recompletions and infill drilling. These activities can 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 $1.2 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. In 2017, we sold the following assets:

Texas Panhandle. In fourth quarter 2017, we sold our oil and gas properties in the Texas Panhandle for proceeds of $40.4 million.

Western Oklahoma. In first six months 2017, we sold certain properties in Western Oklahoma for proceeds of $26.8 million. In fourth quarter 2017, we sold Oklahoma remnant properties for proceeds of $4.0 million.

Miscellaneous. During the year ended December 31, 2017, we sold miscellaneous unproved property, inventory and other assets for proceeds of $1.3 million.

Producing Wells

The following table sets forth information relating to productive wells at December 31, 2017. 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	5,824	5,077	87%
Crude oil	44	43	98%
Total	5,868	5,120	87%

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. This information should not be indicative of future performance nor should it be assumed that there was any correlation between the number of productive wells and the natural gas and oil reserves generated thereby. As of December 31, 2017, we had 56 gross (53.6 net) wells in the process of drilling or active completions stage. In addition, there are 59 gross (58.7 net) wells waiting on completion or waiting on pipelines at year-end 2017.

	2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Productive	176.0	163.5	107.0	100.9	133.0	122.3
Dry	—	—	—	—	—	—
Exploratory wells						
Productive	—	—	1.0	1.0	19.0	19.0
Dry	1.0	1.0	—	—	—	—
Total wells						
Productive	176.0	163.5	108.0	101.9	152.0	141.3
Dry	1.0	1.0	—	—	—	—
Total	177.0	164.5	108.0	101.9	152.0	141.3
Success ratio	99%	99%	100%	100%	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, 2017. Acreage related to option acreage, royalty, overriding royalty and other similar interests is excluded from this summary:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Kansas	—	—	390	390	390	390
Louisiana	90,051	69,922	142,696	134,872	232,747	204,794
New York	—	—	2,265	567	2,265	567
Oklahoma	129,475	80,785	12,127	3,164	141,602	83,949
Pennsylvania	826,870	770,465	110,412	105,253	937,282	875,718
Texas	39,741	26,394	—	—	39,741	26,394
West Virginia	5,876	5,197	—	—	5,876	5,197
Wyoming	—	—	12,468	9,952	12,468	9,952
	1,092,013	952,763	280,358	254,198	1,372,371	1,206,961
Average working interest		87%		91%		88%

Undeveloped Acreage Expirations

The table below summarizes by year our undeveloped acreage scheduled to expire in the next five years. Over 75% of the acres scheduled to expire in 2018 is in North Louisiana and Oklahoma.

	Acres		% of Total
As of December 31,	Gross	Net	Undeveloped
2018	131,474	121,115	48%
2019	36,596	33,314	13%
2020	24,945	23,487	9%
2021	37,630	34,082	13%
2022	15,589	14,707	6%

In all cases the drilling of a commercial well will hold acreage beyond the lease 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 and 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. We currently have no proved undeveloped reserve locations scheduled to be drilled after lease expiration.

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 or overriding 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, 2018, we had 773 full-time 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.

Competition

Competition exists in all sectors of the oil and gas industry and in particular, we encounter substantial competition in developing and acquiring natural gas and oil properties, securing and retaining personnel, conducting drilling and field operations and marketing production. Competitors in exploration, development, acquisitions and production include the major oil and gas companies as well as numerous independent oil and gas companies, individual proprietors and others. Although our sizable acreage position and core area concentration provide some competitive advantages, many competitors have financial and other resources substantially exceeding ours. Therefore, competitors may be able to pay more for desirable leases and evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources allow. We face competition for pipeline and other services to transport our product to markets, particularly in the Northeastern portion of the United States. Competitive advantage is gained in the oil and gas exploration and development industry by employing well-trained and experienced personnel who make prudent capital investment decisions based on management direction, embrace technological innovation and are focused on price and cost management. We have a team of dedicated employees who represent the professional disciplines and sciences that we believe are necessary to allow us to maximize the long-term profitability and net asset value inherent in our physical assets. For more information, see Item 1A. Risk Factors.

Marketing and Customers

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

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

We incur gathering and transportation expense to move our production from the wellhead, tanks and processing plants to purchaser-specified delivery points. These expenses vary based on volume, distance shipped and the fee charged by the third-party gatherers and transporters. In Oklahoma, our production is transported primarily through purchaser-owned or third-party trucks, field gathering systems and transmission pipelines. Transportation capacity on these gathering and transportation systems and pipelines is occasionally constrained. Our Appalachian production is transported on third-party pipelines on which, in most cases, we hold long-term contractual capacity. We attempt to balance sales, storage and transportation positions, which can include purchase of commodities from third parties for resale, to satisfy transportation commitments. In Louisiana, we sell substantially all of our production, which is transported on third-party pipelines, to a variety of purchasers. We also have entered into gas processing agreements that have volumetric requirements.

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

We have entered into several ethane agreements to sell or transport ethane from our Marcellus Shale area. Initial deliveries commenced in late 2013 and deliveries under our most recent agreement began in early 2016. For more information, see Item 1A. Risk Factors – *Our business depends on natural gas and oil transportation and NGLs processing facilities, most of which are owned by others and depends on our ability to contract with those parties.*

Seasonal Nature of Business

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

Markets

Our ability to produce and market oil, NGLs and natural gas profitably depends on numerous factors beyond our control. The effect of these factors cannot be accurately predicted or anticipated. Although we cannot predict the occurrence of events that may affect commodity prices or the degree to which commodity prices will be affected, the prices for any commodity that we produce will generally approximate current market prices in the geographic region of the production.

Governmental Regulation

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

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

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

- leases;
- acquisition of seismic data;

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

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

In December 2007, the FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing ("Order 704"). Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtus of physical natural gas in the previous calendar year, including natural gas gatherers and marketers, are required to report to the FERC, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with the FERC's policy statement on price reporting.

Intrastate gas pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate gas pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate gas pipeline rates, vary from state to state. Additional proposals and proceedings that might affect the gas industry are considered from time to time by the U.S. Congress, FERC, state regulatory bodies and the courts. We cannot predict when or if any such proposals might become effective or their impact, if any, on our operations. We believe that the regulation of intrastate gas pipeline transportation rates will not affect our operations in any way that is materially different from its effects on similarly situated competitors.

Natural gas processing. We depend on gas processing operations owned and operated by third parties. There can be no assurance that these processing operations will continue to be unregulated in the future. However, although the processing facilities may not be directly related, other laws and regulations may affect the availability of gas for processing, such as state regulation of production rates and maximum daily production allowable from gas wells, which could impact our processing.

Gas gathering. Section 1(b) of the NGA exempts gas gathering facilities from FERC jurisdiction. We believe that our gathering facilities meet the traditional tests FERC has used to establish a pipeline system's status as a non-jurisdictional gatherer. There is, however, no bright-line test for determining the jurisdictional status of pipeline facilities. Moreover, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of litigation from time to time, so the classification and regulation of some of our gathering facilities may be subject to change based on future determinations by the FERC and the courts. Thus, we cannot guarantee that the jurisdictional status of our gas gathering facilities will remain unchanged.

While we own or operate some gas gathering facilities, we also depend on gathering facilities owned and operated by third parties to gather from our properties, and therefore we are affected by the rates charged by these third parties for gathering services. To the extent that changes in federal or state regulation affect the rates charged for gathering services at any of these third party facilities, we also may be affected by these changes. We do not anticipate that we would be affected differently than similarly situated gas producers.

Regulation of transportation and sale of oil and NGLs. Intrastate liquids pipeline transportation rates, terms and conditions are subject to regulation by numerous federal, state and local authorities and, in a number of instances, the ability to transport and sell such products on interstate pipelines is dependent on pipelines that are also subject to FERC jurisdiction under the Interstate Commerce Act (the "ICA"). We do not believe these regulations affect us differently than other producers.

The ICA requires that pipelines maintain a tariff on file with the FERC. The tariff sets forth the established rates as well as the rules and regulations governing the service. The ICA requires, among other things, that rates and terms and conditions of service on interstate common carrier pipelines be "just and reasonable". Such pipelines must also provide jurisdictional service in a manner that is not unduly discriminatory or unduly preferential. Shippers have the power to challenge new and existing rates and terms and conditions of service before the FERC.

The FERC currently regulates rates of interstate liquids pipelines, primarily through an annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by the FERC. For the five-year period beginning in July 2016, the FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 1.23 percent. This adjustment is subject to review every five years. Under the FERC's regulations, a liquids pipeline can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-service approach, but only after the pipeline establishes that a substantial divergence exits between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology. Increases in liquids transportation rates may result in lower revenue and cash flow.

In addition, due to common carrier regulatory obligations of liquids pipelines, capacity must be prorated among shippers in an equitable manner in the event there are nominations in excess of capacity by current shippers or capacity requests are received from a new shipper. Therefore, new shippers or increased volume by existing shippers may reduce the capacity available to us. Any prolonged interruption in the operation or curtailment of available capacity of the pipelines that we rely upon for liquids transportation could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Environmental and Occupational Health and Safety Matters

Our operations are subject to numerous federal, state and local laws and regulations governing occupational health and safety, the discharge of materials into the environment or otherwise relating to environmental protection, some of which carry substantial administrative, civil and criminal penalties for failure to comply. These laws and regulations may include but are not limited to:

- the acquisition of a permit before construction commences;
- restriction of the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines;
- governing the sourcing and disposal of water used in the drilling and completion process;

- limiting or prohibiting drilling activities on certain lands lying within wilderness, wetlands, frontier and other protected areas;
- requiring some form of remedial action to prevent or mitigate pollution from existing and former operations such as plugging abandoned wells or closing earthen impoundments; and
- imposing substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings.

These laws and regulations also may restrict the rate of production. Moreover, changes in environmental laws and regulations often occur, and any changes that result in more stringent and costly well construction, drilling, water management or completion activities or more restrictive waste handling, storage, transport, disposal or cleanup requirements for any substances used or produced in our operations could materially adversely affect our operations and financial position, as well as those of the oil and natural gas industry in general.

Oil and gas activities have increasingly faced opposition from environmental organizations and, in certain areas, have been, restricted or banned by governmental authorities in response to concerns regarding the prevention of pollution or the protection of the environment. Moreover, some environmental laws and regulations may impose strict liability regardless of fault or knowledge, which could subject us to liability for conduct that was lawful at the time it occurred or conduct or conditions caused by prior operators or third parties at sites we currently own or where we have sent wastes for disposal. To the extent future laws or regulations are implemented or other governmental action is taken that prohibits, restricts or materially increases the costs of drilling, or imposes environmental protection requirements that result in increased costs to the oil and gas industry in general, our business and financial results could be adversely affected. The following is a summary of some of the environmental laws to which our operations are subject.

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

Waste handling. We also may incur liability under the Resource Conservation and Recovery Act, as amended ("RCRA") and comparable state laws, which impose requirements related to the handling and disposal of non-hazardous solid wastes and hazardous wastes. Drilling fluids, produced waters, and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy are currently regulated by the United States Environmental Protection Agency ("EPA") and state agencies under RCRA's less stringent non-hazardous solid waste provisions. It is possible that these solid wastes could in the future be reclassified as hazardous wastes, whether by amendment of RCRA or adoption of new laws, which could significantly increase our costs to manage and dispose of such wastes. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils, may be regulated as hazardous wastes. Although the costs of managing wastes classified as hazardous waste may be significant, we do not expect to experience more burdensome costs than similarly situated companies in our industry. Also, in December 2016, the EPA agreed in a consent decree to review its regulation of oil and gas waste. It has until March 2019 to determine whether any revisions are necessary. Any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

We currently own or lease, and have in the past owned or leased, properties that have been used for many years for the exploration and production of crude oil and natural gas. Petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us, or on or under other locations where such materials have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons and wastes was not under our control. These properties and the materials disposed or released on them may be subject to CERCLA, RCRA and comparable state laws and regulations. Under such laws and regulations, we could be required to remove or remediate previously disposed wastes or property contamination, or to perform remedial activities to prevent future contamination.

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

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

The Underground Injection Control (“UIC”) Program authorized by the Safe Drinking Water Act prohibits any underground injection unless authorized by a permit. In connection with our operations, Range may dispose of produced water in underground wells, which are designed and permitted to place the water into deep geologic formations, isolated from fresh water sources. However, because some states have become concerned that the disposal of produced water could under certain circumstances contribute to seismicity, they have adopted or are considering adopting additional regulations governing such disposal. For example, in January 2016, Ohio lawmakers proposed new legislation that would, among other things, require injection wells be located more than 2,000 feet from any occupied dwelling. While that particular legislation did not become law, should similar onerous regulations or bans relating to underground wells be placed in effect in areas where Range has significant operations, there could be an impact on Range’s ability to operate.

Hydraulic fracturing. Hydraulic fracturing, which has been used by the industry for over 60 years, is an important and common practice to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely apply hydraulic fracturing techniques as part of our operations. This process is typically regulated by state environmental agencies and oil and natural gas commissions; however, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final Clean Air Act (as defined below) regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; proposed effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Additionally, while the Federal Bureau of Land Management (“BLM”) released a final rule setting forth disclosure requirements and other regulatory mandates for hydraulic fracturing on federal lands in March 2015, on December 29, 2017, the U.S. Department of Interior rescinded the 2015 rule that would have set new environmental limitations on hydraulic fracturing, or fracking, on public lands because it believed the 2015 rule imposed administrative burdens and compliance costs that were not justified. Moreover, from time to time, Congress has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. In addition to any actions by Congress, certain states in which we operate, including Pennsylvania and Texas, have adopted, and other states are considering adopting, regulations imposing or that could impose new or more stringent permitting, public disclosure, or well construction requirements on hydraulic fracturing operations. States could also elect to prohibit hydraulic fracturing altogether, such as in the State of New York. Local governments also may seek to adopt ordinances within their jurisdiction regulating the time, place or manner of drilling activities in general or hydraulic fracturing activities in particular. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we currently or in the future plan to operate, we may incur additional, more significant, costs to comply with such requirements and also could become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development, or production activities.

In addition, certain government reviews are underway that focus on environmental aspects of hydraulic fracturing practices. On December 13, 2016, the EPA issued its final report on the potential of hydraulic fracturing to impact drinking water resources through water withdrawals, spills, fracturing directly into such resources, underground migration of liquids and gases, and inadequate treatment and discharge of wastewater which did not find evidence that these mechanisms have led to widespread, systematic impacts on drinking water resources. However, the EPA's report did identify future efforts that could be taken to further understand the potential of hydraulic fracturing to impact drinking water resources, including ground water and surface water monitoring in areas with hydraulically fractured oil and gas production wells. Based on the EPA's study, existing regulations and our practices, we do not believe our hydraulic fracturing operations are likely to impact drinking water resources but the EPA study could result in initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

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

Air emissions. The Clean Air Act of 1963 (as amended, the "Clean Air Act"), and comparable state laws restrict the emission of air pollutants from many sources, including compressor stations. These laws and any implementing regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, impose stringent air permit requirements, or use specific equipment or technologies to control emissions. We may be required to incur certain capital expenditures in the next few years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals for emissions of pollutants. For example, pursuant to then President Obama's Strategy to Reduce Methane Emissions in August 2015, the EPA proposed new regulations that would set methane emission standards for new and modified oil and natural gas production and natural gas processing and transmission facilities as part of the Obama Administration's efforts to reduce methane emissions from the oil and natural gas sector by up to 45 percent from 2012 levels by 2025. The EPA finalized these new regulations on June 3, 2016 to be effective August 2, 2016; however on June 12, 2017 the EPA announced a proposed 2 year stay on these fugitive emissions standards "while the agency reconsiders them". Therefore, the date when and if these standards may become implemented is still not known. In a second example, in October 2015, the EPA finalized a rulemaking proposal that revises the National Ambient Air Quality Standard for ozone to 70 parts per billion for both the 8-hour primary and secondary standards. Compliance with one or both of these regulatory initiatives could directly impact us by requiring installation of new emission controls on some of our equipment, resulting in longer permitting timelines, and significantly increasing our capital expenditures and operating costs, which could adversely impact our business.

Climate change. In 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present a danger to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic conditions. Based on these findings, the EPA adopted regulations under the existing Clean Air Act establishing Title V and Prevention of Significant Deterioration ("PSD") permitting reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. We could become subject to these Title V and PSD permitting reviews and be required to install "best available control technology" to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future if such facilities emitted volumes of GHGs in excess of threshold permitting levels. The EPA has also adopted rules requiring the reporting of GHG emissions from specified emission sources in the United States on an annual basis, including certain oil and natural gas production facilities, which include several of our facilities. We believe that our monitoring activities and reporting are in substantial compliance with applicable obligations.

Congress has from time to time considered legislation to reduce emissions of GHGs and there have been a number of federal regulatory initiatives to address GHG emissions in recent years, such as the establishing of Title V and PSD permitting reviews for GHG emissions as described in more detail above. Additionally, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future federal or state laws and regulations, or international compacts, could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emission allowances or comply with new regulatory or reporting requirements. On an international level, the United States was one of almost 200 nations that, in December 2015, agreed to an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets, which agreement formally entered into force on November 4, 2016. While the United States formally accepted that agreement in September 2016, on June 1, 2017, President Trump determined to withdraw the United States from the Paris Agreement. Under the term of the Paris Agreement, the earliest possible effective date for withdrawal by the United States is November 4, 2020, four years after the agreement came into effect. Future United States regulations on GHG emissions designed to meet the Paris Agreement goals could impact us in ways that cannot be determined at this time.

While it is unclear at this time whether President Trump or Congress will pursue legislation or regulation to address GHG emissions in light of the withdrawal of the Paris Agreement, any such legislation or regulatory programs could also increase the cost of consuming, and thereby could reduce demand for the oil and natural gas that we produce. However, President Trump has taken certain actions since taking office that have begun to establish a national policy in favor of energy independence and economic growth. For example, on March 28, 2017, President Trump issued an Executive Order for the purpose of facilitating the development of United States energy resources and reducing unnecessary regulatory burdens associated with the development of those resources. Through the Executive Order, President Trump has directed agencies to review existing regulations that potentially burden the development of domestic energy resources, and appropriately suspend, revise, or rescind regulations that unduly burden the development of United States energy resources beyond what is necessary to protect the public interest or otherwise comply with the law. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

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

Endangered species. The federal Endangered Species Act of 1973, as amended (the "ESA"), restricts activities that may affect endangered and threatened species or their habitats. If endangered species are located in an area where we wish to conduct seismic surveys, development activities or abandonment operations, or are located in an area where new pipelines are planned; the work could be prohibited or delayed or expensive mitigation may be required. Moreover, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas. As a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service ("FWS") was required to make a determination on the listing of numerous species as endangered or threatened under the Endangered Species Act prior to the completion of the agency's 2017 fiscal year. For example, while the lesser prairie chicken is not currently designated as threatened or endangered, in November 2016, the FWS issued its 90-day findings in response to a petition to reclassify the lesser prairie chicken under the ESA. In those findings, FWS found that the petition presented substantial information that the petitioned action may be warranted, prompting a thorough status review. We cannot predict the outcome of this review process. The designation of currently unprotected species, including the lesser prairie chicken, as threatened or endangered in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves.

The Migratory Bird Treaty Act ("MBTA") implements various treaties and conventions between the United States and certain other nations for the protection of migratory birds. In accordance with this law, the taking, killing or possessing of migratory birds covered under this act is unlawful without a permit. If there is the potential to adversely affect migratory birds as a result of our operations, we may be required to obtain necessary permits to conduct those operations, which may result in specified operating restrictions on a temporary, seasonal, or permanent basis in affected areas and an adverse impact on our ability to develop and produce our reserves. However, in December 2017, the U.S. Department of Interior stated in a solicitor's opinion that it will no longer prosecute oil and gas, wind and solar operators that accidentally kill birds based on a reinterpretation of the MBTA that it does not prohibit accidental takings of migratory birds.

We believe we are in substantial compliance with currently applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2017, nor do we anticipate that such expenditures will be material in 2018. However, we regularly have expenditures to comply with environmental laws and we anticipate those costs will continue to be incurred in the future.

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

GLOSSARY OF CERTAIN DEFINED TERMS

The terms defined in this glossary are used in this report.

bbl. One stock tank barrel, or 42 U.S. gallons liquid volumes, used herein in reference to crude oil or other liquid hydrocarbons.

bcf. One billion cubic feet of gas.

bcfe. One billion cubic feet of natural gas equivalents, based on a ratio of 6 mcf for each barrel of oil or NGLs, which reflects relative energy content.

btu. One British thermal unit, an energy equivalence measure. A British thermal unit is the heat required to raise the temperature of one pound of water from 58.5 to 59.5 degrees Fahrenheit.

Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing oil or natural gas in sufficient economic quantities.

Exploratory well. A well drilled to find oil or gas in an unproved area, to find a new reservoir in an existing field previously found to be productive of oil and gas in another reservoir or to extend a known reservoir.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Henry Hub price. A natural gas benchmark price quoted at settlement date average.

mbbl. One thousand barrels of crude oil or other liquid hydrocarbons.

mcf. One thousand cubic feet of gas.

mcf per day. One thousand cubic feet of gas per day.

mcfe. One thousand cubic feet of natural gas equivalents, based on a ratio of 6 mcf for each barrel of oil or NGLs, which reflects relative energy content.

mmbbl. One million barrels of crude oil or other liquid hydrocarbons.

mmbtu. One million British thermal units.

mmcf. One million cubic feet of gas.

mmcfe. One million cubic feet of gas equivalents.

NGLs. Natural gas liquids, which are naturally occurring substances found in natural gas, including ethane, butane, isobutane, propane and natural gasoline that can be collectively removed from produced natural gas, separated into these substances and sold.

Net acres or Net wells. The sum of the fractional working interests owned in gross acres or gross wells.

NYMEX. New York Mercantile Exchange.

Present Value (PV). The present value of future net cash flows, using a 10% discount rate, from estimated proved reserves, using constant prices and costs in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions). The after tax present value is the Standardized Measure.

Productive well. A well that is producing oil or gas or that is capable of production.

Proved developed non-producing reserves. Reserves that consist of (i) proved reserves from wells which have been completed and tested but are not producing due to lack of market or minor completion problems which are expected to be corrected and (ii) proved reserves currently behind the pipe in existing wells and which are expected to be productive due to both the well log characteristics and analogous production in the immediate vicinity of the wells.

Proved developed reserves. Proved reserves that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well and (ii) through installed extracting equipment and infrastructure operational at the time of the reserve estimate if the extraction is by means not involving a well.

Proved reserves. The quantities of crude oil, natural gas and NGLs that geological and engineering data can estimate with reasonable certainty to be economically producible within a reasonable time from known reservoirs under existing economic, operating and regulatory conditions prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain.

Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Recompletion. The completion for production an existing well bore in another formation from that in which the well has been previously completed.

Reserve life index. Proved reserves at a point in time divided by the then production rate (annually or quarterly).

Royalty acreage. Acreage represented by a fee mineral or royalty interest which entitles the owner to receive free and clear of all production costs a specified portion of the oil and gas produced or a specified portion of the value of such production.

Royalty interest. An interest in an oil and gas property entitling the owner to a share of oil and natural gas production free of costs of production.

Standardized Measure. The present value, discounted at 10%, of future net cash flows from estimated proved reserves after income taxes, calculated holding prices and costs constant at amounts in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions) and otherwise in accordance with the Commission’s rules for inclusion of oil and gas reserve information in financial statements filed with the Commission.

tcfe. One trillion cubic feet of natural gas equivalents, with one barrel of NGLs or crude oil being equivalent to 6,000 cubic feet of natural gas.

Unproved properties. Properties with no proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production, subject to all royalties, overriding royalties and other burdens, and to all costs of exploration, development and operations, and all risks in connection therewith.

Unconventional play. A term used in the oil and gas industry to refer to a play in which the targeted reservoirs generally fall into one of three categories: (1) tight sands, (2) coal beds or (3) shales. The reservoirs tend to cover large areas and lack the readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require fracture stimulation or other special recovery processes in order to achieve economic flow rates.

ITEM 1A. RISK FACTORS

We are subject to various risks and uncertainties in the course of our business. The following summarizes the known material risks and uncertainties that may adversely affect our business, financial condition or results of operations. When considering an investment in our securities, you should carefully consider the risk factors included below as well as those matters referenced in foregoing pages under "Disclosures Regarding Forward-Looking Statements" and other information included and incorporated by reference into this Annual Report on Form 10-K. These risks are not the only risks we face. Our business could also be impacted by additional risks and uncertainties not currently known to us or that we currently deem to be immaterial.

Risks Related to Our Business

Volatility of natural gas, NGLs and oil prices significantly affects our cash flow and capital resources and could hamper our ability to operate economically. Natural gas, NGLs and oil prices are volatile, and a decline in prices adversely affects our profitability and financial condition. The oil and gas industry is typically cyclical and we expect the volatility to continue. Between 2014 and 2017, the average NYMEX monthly settlement price of natural gas has been as high as $5.56 per Mmbtu and as low as $1.71 per Mmbtu. During that same time frame, the average NYMEX monthly oil settlement price was as high as $105.15 per barrel and as low as $30.62 per barrel. Over the past few months, natural gas and oil prices have increased with the average NYMEX monthly settlement price for natural gas for February 2018 increasing to $3.63 per Mmbtu and the monthly settlement for crude oil increasing to $63.66 per barrel in January 2018. Likewise, NGLs have suffered significant recent declines in realized prices. NGLs are made up of ethane, propane, isobutane, normal butane and natural gasoline, all of which have different uses and different pricing characteristics, which adds further volatility to the pricing of NGLs. A further or extended decline in commodity prices could materially and adversely affect our business, cash flow, financial condition and results of operations. Natural gas prices are likely to affect us more than oil prices because approximately 67% of our December 31, 2017 proved reserves are natural gas.

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

- the domestic and foreign supply of, and demand for, natural gas, NGLs and oil;
- domestic and world-wide economic conditions;
- the level and effect of trading in commodity futures markets, including commodity price speculators and others;
- weather conditions;
- technological advances affecting energy consumption and production;
- the price and level of foreign imports;
- U.S. domestic and worldwide economic conditions;
- the availability, proximity and capacity of transportation facilities, processing and storage facilities;
- the effect of worldwide energy conservation efforts;
- the ability of the members of the Organization of Petroleum Exporting Countries and other exporting nations that work together to agree and maintain oil price and production controls;
- expansion of U.S. exports of oil, NGLs and/or liquefied natural gas;
- military, economic and political conditions in natural gas and oil producing regions;
- the cost of exploring for, developing, producing, transporting and marketing natural gas, NGLs and oil: and
- domestic (federal, state and local) and foreign governmental regulations and taxes.

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

Producing natural gas, NGLs and oil may involve unprofitable efforts. As of December 31, 2017, the relationship between the price of oil and the price of natural gas continues to be at a wide spread. Normally, NGLs production is a by-product of natural gas production. At times, we and other producers may choose to sell natural gas at below cost, or otherwise dispose of natural gas to allow for the profitable sale of only oil, NGLs and condensate. The prices of NGLs can be unpredictable. For example, over the past four years, the average Mont Belvieu NGL composite price has been as high as $0.98 per gallon and as low as $0.30 per gallon. Such volatility in the pricing of NGLs complicates such decisions and may materially and adversely affect the profitability of such decisions.

Information concerning our reserves and future net cash flow estimates is uncertain. There are numerous uncertainties inherent in estimating quantities of proved natural gas and oil reserves and their values, including many factors beyond our control. Estimates of proved reserves are by their nature uncertain and depend on many assumptions relating to current and further economic conditions and commodity prices. To the extent we experience a sustained period of reduced commodity prices, there is a risk that a portion of our proved reserves could be deemed uneconomic and no longer be classified as proved. Although we believe these estimates are reasonable, actual production, revenues and costs to develop will likely vary from estimates and these variances could be material.

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

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

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

If natural gas, NGLs and oil prices remain depressed or drilling efforts are unsuccessful, we may be required to record writedowns of our proved natural gas and oil properties. We have been required to write down the carrying value of certain of our natural gas and oil properties in the past and there is a risk that we will be required to take additional writedowns in the future. Recent commodity price declines have resulted in an impairment of our proved oil and gas properties. For example, in third quarter 2015, we recorded a $502.2 million impairment of natural gas and oil properties in Northern Oklahoma and our legacy producing assets in Northwest Pennsylvania, and in fourth quarter 2015, we recorded an additional impairment of $87.9 million primarily related to our natural gas and oil properties in the Texas Panhandle. In first quarter 2016, we recorded a $43.0 million proved property impairment in Western Oklahoma. In third quarter 2017, we recorded a $63.7 million proved property impairment related to our natural gas and oil properties in the Texas Panhandle and Northern Oklahoma. These impairments were due to a significant decline in commodity prices and the potential sale of certain of these properties. Writedowns may occur in the future when natural gas and oil prices are low, or if we have downward adjustments to our estimated proved reserves, increases in our estimates of operating or development costs, deterioration in our drilling results or mechanical problems with wells where the cost to redrill or repair is not supported by the expected economics. Because our reserves are predominately natural gas, changes in natural gas prices have a more significant impact on our financial results.

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

We evaluate our unproved oil and gas properties for impairment and could be required to recognize noncash charges in the earnings of future periods. At December 31, 2017, our unproved natural gas and oil properties were $2.6 billion. Our analysis of these costs is affected by the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of the leases. Impairment of a significant portion of our unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success.

We periodically evaluate our goodwill for impairment and could be required to recognize noncash charges in the earnings of future periods. At December 31, 2017, we have goodwill of $1.6 billion. Goodwill is assessed for impairment annually during the fourth quarter or whenever facts or circumstances indicate that the carrying value of our business may be impaired which may require an estimate of the fair values of our assets and liabilities. Those assessments may be affected by:

- additional reserve adjustments both positive and negative;
- results of drilling activities;
- management's outlook for commodity prices and costs and expenses;
- changes in our market capitalization;
- changes in our weighted average cost of capital; and
- changes in income taxes.

If the fair value of our net assets is not sufficient to fully support the goodwill balance in the future, we may be required to reduce the carrying value of goodwill for the impaired value and incur a corresponding noncash charge to earnings in the period in which goodwill is determined to be impaired.

Significant capital expenditures are required to replace our reserves. Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flow from operations, our bank credit facility and debt and equity issuances. We have also engaged in asset monetization transactions. Currently, we have set our capital expenditures in 2018 to closely align with our projected cash flows from operations in 2018. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of natural gas, NGLs and oil and our success in developing and producing new reserves. If our access to capital were limited due to various factors, which could include a decrease in revenues due to lower natural gas, NGLs and oil prices or decreased production or deterioration of the credit and capital markets, we would have a reduced ability to replace our reserves. We may not be able to incur additional bank debt, issue debt or equity, engage in asset monetization or access other methods of financing on an economic basis to meet our reserve replacement requirements.

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

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

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

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

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

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

Our operations involve utilizing drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling horizontal wells include, but are not limited to, the following:

- landing the wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running casing the entire length of the wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that we face while completing horizontal wells include, but are not limited to, the following:

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation state.

Drilling in emerging areas is more uncertain than drilling in areas that are more developed and have a longer history of established drilling operations. New discoveries and emerging formations have limited or no production history and, consequently, we are more limited in assessing future drilling results in these areas. If our drilling results are worse than anticipated, the return on investment for a particular project may not be as attractive as anticipated and we may recognize noncash impairment charges to reduce the carrying value of its unproved properties in those areas.

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

We may incur losses as a result of title defects in the properties in which we invest. It is our practice in acquiring oil and natural gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest. Rather, we rely upon the judgement of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition.

Prior to the drilling of an oil or natural gas well, however, it is the normal practice in our industry for the person or company acting as the operator of the well to obtain a preliminary title review to ensure there are no obvious defects in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct defects in the marketability of the title, and such curative work entails expense. Our failure to cure any title defects may delay or prevent us from utilizing the associated mineral interest, which may adversely impact our ability in the future to increase production and reserves. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in the assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

Our producing properties are largely concentrated in the Appalachian Basin, making us vulnerable to risks associated with operating in a significant geographic area. Our producing properties are geographically concentrated in the Appalachian Basin in Pennsylvania. At December 31, 2017, 91% of our total estimated proved reserves were attributable to properties located in Pennsylvania. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, state politics, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages or interruption of the processing or transportation of crude oil, condensate, natural gas or NGLs.

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

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

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

- we may be required to dedicate a substantial portion of our cash flows from operations to the payment of our indebtedness, reducing the funds available for our operations;
- a portion of our borrowings is at variable rates of interest, making us vulnerable to increases in interest rates;
- we may be more highly leveraged than some of our competitors, which could place us at a competitive disadvantage;
- our degree of leverage may make us more vulnerable to a downturn in our business or the general economy;
- we are subject to numerous financial and other restrictive covenants contained in our existing debt agreements, which restrict our ability to engage in certain activities and could limit our growth, and the breach of such covenants, which could materially and adversely impact our financial performance;
- our debt level could limit our flexibility to grow the business and in planning for, or reacting to, changes in our business and the industry in which we operate; and
- we may have difficulties borrowing money in the future.

The risks described above may further increase in the event we incur additional debt. In addition to those risks above, we may not be able to obtain funding on acceptable terms.

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

We receive debt ratings from the major credit rating agencies in the United States. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales and near-term and long-term growth opportunities. Liquidity, asset quality, cost structure, product mix and commodity pricing levels are also considered by the rating agencies. A ratings downgrade could adversely impact our ability to access debt markets in the future, increase the cost of future debt and potentially require us to post letters of credit or other forms of collateral for certain obligations.

As a result of cross-default provisions in our borrowing arrangements, we may be unable to satisfy all of our outstanding obligations in the event of a default on our part. The terms of our senior indebtedness, including our revolving credit facility, contain cross-default provisions which provide that we will be in default under such agreements in the event of certain defaults under our indentures or other loan agreements. Accordingly, should an event of default above certain thresholds occur under any of those agreements, we face the prospect of being in default under all of our debt agreements, obliged in such instance to satisfy all of our outstanding indebtedness and unable to satisfy all of our outstanding obligations simultaneously. In such an event, we might not be able to obtain alternative financing or, if we are able to obtain such financing, we might not be able to obtain it on terms acceptable to us, which would negatively affect our ability to implement our business plan, make capital expenditures and finance our operations.

We are subject to financing and interest rate exposure risks. Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in our credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. For example, at December 31, 2017, approximately 71% of our debt is at fixed interest rates with the remaining 29% subject to variable interest rates.

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

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

Derivative transactions may limit our potential gains and involve other risks. To manage our exposure to price risk, we currently and may in the future enter into derivative arrangements, utilizing commodity derivatives with respect to a portion of our future production. Such hedges are designed to lock in prices so as to limit volatility and increase the predictability of cash flow. These transactions limit our potential gains if natural gas, NGLs and oil prices rise above the price established by the hedge. In addition, derivative transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

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

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

We are exposed to a risk of financial loss if a counterparty fails to perform under a derivative contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to mitigate the risk may be limited depending upon market conditions. Furthermore, the bankruptcy of one or more of our hedge providers, or some other similar proceeding or liquidity constraint, might make it unlikely that we would be able to collect all or a significant portion of amounts owed to us by the distressed entity or entities. During periods of falling commodity prices our hedge receivable positions increase, which increases our exposure. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss.

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

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

Our operations are subject to numerous and increasingly strict federal, state and local laws, regulations and enforcement policies relating to the environment. We may incur significant costs and liabilities in complying with existing or future environmental laws, regulations and enforcement policies and may incur costs arising out of property or natural resource damage or injuries to employees and other persons. These costs may result from our current and former operations and may even be caused by previous owners of property we own or lease or relate to third party sites where we have taken materials for recycling or disposal. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties as well as corrective action orders. Matters subject to regulation include, but are not limited to, the following:

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

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

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

Congress has from time to time considered legislation to reduce emissions of GHGs and there have been a number of federal regulatory initiatives to address GHG emissions in recent years. These include the establishing of Title V and PSD permitting reviews for GHG emissions from certain large stationary sources that are already major potential sources of certain principal, or criteria, pollutant emissions, and the implementation of a GHG monitoring and reporting program for certain sectors of the natural gas and oil industry, including onshore and production, which includes certain of our operations. Additionally, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs, in which major sources of GHG emissions acquire and surrender emission allowances in return for emitting those GHGs. The outcome of federal and state actions to address global climate change could result in a variety of regulatory programs including potential new regulations to control or restrict emissions, taxes or other charges to deter emissions of GHGs, energy efficiency requirements to reduce demand, or other regulatory actions. For example, the EPA finalized new regulations in 2016 that would set methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities in an effort to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025; however, on June 12, 2017 the EPA announced a proposed 2 year stay on fugitive emissions standards "while the agency reconsiders them." Therefore, the date when and if these standards may become implemented is still not known. If these or any other actions to address GHG emissions do become implemented in the future, they could:

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

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

Our business is subject to operating hazards that could result in substantial losses or liabilities that may not be fully covered under our insurance policies. Natural gas, NGLs and oil operations are subject to many risks, including well blowouts, craterings, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, pipe or cement failures, pipeline ruptures or spills, vandalism, pollution, releases of toxic gases, adverse weather conditions or natural disasters, and other environmental hazards and risks. If any of these hazards occur, we could sustain substantial losses as a result of:

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

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

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

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

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

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase. Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by the FERC as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests the FERC has used to establish a pipeline’s status as a gatherer not subject to regulation as a natural gas company. However, we have not received a declaratory order from the FERC regarding our natural gas gathering pipelines and the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by the FERC, the courts or Congress.

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

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

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

Certain federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated, and additional state taxes on natural gas extraction may be imposed, as a result of future legislation. Legislation previously has been proposed that would, if enacted into law, make significant changes to U.S. federal income tax laws, including the elimination of certain U.S. federal income tax benefits currently available to oil and gas exploration and production companies. Such changes include, but are not limited to, (i) the elimination of current deductions for intangible drilling and development costs and; (ii) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective. As of December 31, 2017, we had a tax basis of $2.2 billion related to prior years' capitalized intangible drilling costs, which will be amortized over the next five years.

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

The Tax Cuts and Jobs Act of 2017 was signed into law on December 22, 2017 by President Trump. The law includes significant changes to the United States corporate income tax system, including a federal corporate rate reduction from 35% to 21%, limitations on the deductibility of interest expense and executive compensation, and the transition of United States international taxation from a worldwide tax system to a territorial tax system. The new law also limits the utilization of net operating loss carryforwards to 80% of taxable income and makes some fringe benefits no longer deductible. While the initial implementation of the new law had a material impact on our December 31, 2017 financial statements, we do not expect it to have a material impact on our taxes payable or net operating loss carryforwards. Our net deferred tax assets and liabilities have been revalued at the newly enacted U.S. corporate rate and the impact was recognized in tax expense in 2017. At December 31, 2017, we have not completed our accounting for the tax effects of the enactment of this new tax law and its impact on our deferred tax balances. Due to the complexities involved in accounting for the new law, the SEC Staff Accounting Bulletin ("SAB") 118 allows us to provide a provisional estimate in our earnings for the year ended December 31, 2017. We have made a reasonable estimate of this impact on our existing deferred tax balances and we will continue to analyze the effect. Any adjustments will be recorded as they are identified during the measurement period provided for in SAB 118.

In February 2012, the state legislature of Pennsylvania passed legislation creating a natural gas impact fee applicable to production in Pennsylvania. As noted above, the majority of our acreage in the Marcellus Shale is located in Pennsylvania. The legislation imposes an annual fee on natural gas and oil operators for each well drilled for a period of fifteen years. Much like a severance tax, the fee is on a sliding scale set by the Public Utility Commission and is based on two factors: changes in the Consumer Price Index and the average NYMEX natural gas prices on the last day of each month. The impact fee increases the financial burden on our operations in the Marcellus Shale. There can be no assurance that the impact fee will remain as currently structured or that additional taxes will not be imposed. There are currently proposals by the Pennsylvania Governor and various Pennsylvania state lawmakers to enact a severance tax in substitution for, or as an addition to, the impact fee already in place, which could be based on the volume of gas produced rather than on a per-well basis. In addition, a recent court case in Pennsylvania addressed the constitutionality of the 2007 net operating loss deduction ("NOLD") limitation under the Uniformity Clause of the Pennsylvania Constitution, which limited the use of NOLDs to the greater of $3 million or 12.5 percent of taxable income. On October 18, 2017, the Supreme Court of Pennsylvania issued its decision on this case holding that the NOLD limitation as applied to the 2007 taxable year at issue violated the Uniformity Clause of the Pennsylvania Constitution and struck the $3 million flat cap limitation, but not the percentage of taxable income limitation. Shortly after the Supreme Court Case, the Pennsylvania Governor signed a bill that removed the flat cap NOLD limitation and increased the percentage of taxable income limitation. For taxable years beginning after December

31, 2017, the net operating loss carryforward is limited to 35 percent of taxable income and limited to 40 percent for the year ended December 31, 2018.

Changes in laws or regulations relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays and adversely affect our production. The use of hydraulic fracturing is necessary to produce commercial quantities of natural gas and oil from many reservoirs, especially shale formations such as the Marcellus Shale. The process is typically regulated by state environmental agencies and oil and gas commissions. However, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final Clean Air Act regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; proposed effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Additionally, in 2015 the BLM enacted a new rule setting forth disclosure requirements and other regulatory mandates for hydraulic fracturing on federal lands; however, on December 29, 2017, the U.S. Department of Interior rescinded the 2015 rule because it believed the 2015 rule imposed administrative burdens and compliance cost that were not justified.

From time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Certain states, in which we operate, including Pennsylvania and Texas, have adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosure or well-construction requirements on hydraulic fracturing operations. States could elect to prohibit hydraulic fracturing altogether, as Governor Andrew Cuomo of the State of New York announced in December 2014 with regard to fracturing activities in New York. Local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general and/or hydraulic fracturing in particular. In the event federal, state or local restrictions or prohibitions are adopted in areas where we conduct operations, we may incur significant costs to comply with such requirements or we may experience delays or curtailment in the pursuit of exploration, development, or production activities, and possibly be limited or precluded in the drilling of wells or in the amounts that we are ultimately able to produce from our reserves. Moreover, a number of federal entities are analyzing a variety of environmental issues associated with hydraulic fracturing. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources “under some circumstances,” noting that the following hydraulic fracturing water cycle activities and local-or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas or low water availability; surface spills during the management of fracturing fluids, chemicals or produced water, injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. Since the report did not find a direct link between hydraulic fracturing itself and contamination of groundwater resources, we do not believe that this multi-year study and subsequent report provides any basis for further regulation of hydraulic fracturing at the federal level. However, the EPA’s report did identify future efforts that could be taken to further understand the potential of hydraulic fracturing impact to drinking water resources, including groundwater and surface water monitoring in areas with hydraulically fractured oil and gas production wells.

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

Legislation or regulatory initiatives intended to address seismic activity in Oklahoma and elsewhere could increase our costs of compliance or lead to operational delays, which could have a material adverse effect on our business, results of operations or financial condition. We dispose of large volumes of water produced alongside natural gas and oil (or produced water) in connection with our drilling and production operations, pursuant to permits issued to us by governmental authorities overseeing such disposal activities. While these permits are issued under existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities.

There exists a growing concern that the injection of produced water into belowground disposal wells triggers seismic events in certain areas, including Oklahoma and Texas, where we have limited operations. In response to these concerns, regulators in some states are pursuing initiatives designed to impose additional requirements in the permitting and operating of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. Legislative and regulatory initiatives intended to address these concerns may result in additional levels of regulation that could lead to operational delays, increase operating and compliance costs or otherwise adversely affect operations. For example, Oklahoma has taken numerous regulatory actions in response to concerns related to the operation of produced water disposal wells and induced seismicity. Oklahoma has adopted a "traffic light" system, wherein the Oklahoma Corporation Commission (the "OCC") reviews new or existing disposal wells for proximity to faults, seismicity in the area and other factors in determining whether such wells should be permitted, permitted only with special restrictions, or not permitted. The granting of a permit may be conditioned upon the operator complying with several additional regulatory requirements including, without limitation:

- monitoring and recording well pressure and injected volume on a daily basis;
- conducting more frequent mechanical integrity testing;
- reducing the depth of, or "plugging back" such well; and/or
- reducing injection volumes for such well by as much as 50%.

Additional regulatory action in this area is likely and the Oklahoma legislature has introduced new legislation to expand the OCC's authority to address concerns related to disposal wells and induced seismicity. For example, in March 2016, the Oklahoma legislature passed a bill authorizing the OCC to take emergency action with regard to disposal well operations or other activities within its jurisdiction when public safety or the environment is at risk.

In 2014, the Texas Railroad Commission ("TRC") published a new rule governing permitting of disposal wells that would require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question.

Restriction on the volumes permissible for injection or a lack of alternative waste disposal sites could cause us to delay, curtail or discontinue our exploration and development plans. Increased costs associated with the transportation and disposal of produced water, including the cost of complying with regulations concerning produced water disposal, such as mandated produced water recycling in some portion of all of our operations, may reduce our profitability. These developments may result in additional regulations, or increased complexity and costs with respect to existing regulations, that could lead to operational delays or increased operating and compliance costs. Such delays or increased costs which could have a material adverse effect on our business, results of operations, cash flows or financial condition.

The enactment of derivatives legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act"), enacted in July 2010, established federal oversight and regulation of the over-the-counter derivatives market and entities, including Range, that participate in that market. The Act requires the Commodities Futures Trading Commission (the "CFTC") and the SEC to promulgate rules and regulations implementing the Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position limits rule was vacated by the United States District Court for the District of Columbia in September 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. In December 2016, the CFTC voted unanimously to repropose regulations implementing limits on speculative futures and swaps positions as called for in the Act. In a separate vote, CFTC approved final aggregation regulations, which are a key component of the CFTC's existing position limits regime. In response to comments on a prior proposal published in December 2013, and on a supplemental proposal published in June 2016, the CFTC is, among other things, reproposing limits on speculative position in 25 core physical commodity futures contracts and their "economically equivalent" futures, options, and swaps (referenced contracts), and is deferring action on three cash-settled commodities. The CFTC is also reproposing the definition of bona fide hedging position, as well as exemptions for bona fide hedging positions in physical commodities. Exemptions are being reproposed for, among other things, positions that are established in good faith prior to the effective date of the initial limits that would be established by regulations. As these CFTC reproposals are not yet final, the impact on us is uncertain at this time.

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

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

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

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

Our business depends on natural gas and oil transportation and NGLs processing facilities, most of which are owned by others and depends on our ability to contract with those parties. Our ability to sell our natural gas, NGLs and oil production depends in part on the availability, proximity and capacity of pipeline systems and processing facilities owned by third parties and our ability to contract with those third parties. The lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Although we have some contractual control over the transportation of our product, material changes in these business relationships, including the financial condition of these third parties, could materially affect our operations. In some cases, we do not purchase firm transportation on third party facilities and therefore, our production transportation can be interrupted by those having firm arrangements. In other cases, we have entered into firm transportation arrangements, particularly in the Marcellus Shale where we are obligated to pay fees on minimum volumes regardless of actual volume throughput. If production decreases due to developmental activities, taking into consideration the current commodity price environment, production related difficulties or otherwise, we may be unable to meet our obligations under existing firm transportation contracts, resulting in fees, which may be significant and may have a material adverse effect on our operations. We have also entered into long-term agreements with third parties to provide natural gas gathering and processing services in the Marcellus Shale. In some cases, the capacity of gathering systems and transportation pipelines may be insufficient to accommodate potential production from existing and new wells. Federal and state regulation of natural gas and oil production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport natural gas, NGLs and oil. If any of these third party pipelines or other facilities become partially or fully unavailable to transport or process our product, or if the natural gas quality specifications for a natural gas pipeline or facility changes so as to restrict our ability to transport natural gas on those pipelines or facilities, our revenues could be adversely affected.

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

In North Louisiana, we have contracts with midstream providers for gathering and processing services with minimum volume delivery commitments. We are obligated to pay fees on minimum volumes to midstream service providers regardless of actual volume throughput. These fees could be significant and may have a material adverse effect on our operations.

Acquisitions are subject to the risks and uncertainties of evaluating reserves and potential liabilities and may be disruptive and difficult to integrate into our business. We could be subject to significant liabilities related to our acquisitions. It is generally not feasible to review in detail every individual property included in an acquisition. Ordinarily, a review is focused on higher-valued properties. However, even a detailed review of all properties and records may not reveal existing or potential problems in all of the properties, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Initial estimates of reserves may be subject to revisions following an acquisition which may materially and adversely affect the desired benefits of the acquisition.

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

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

Significant acquisitions, including the MRD Merger (as defined herein), present potential risks, including:

- difficulties in operating a significantly larger combined organization and integrating additional operations into ours;
- difficulties in the assimilation of the assets and operations of the acquired businesses, especially if the assets acquired are in a new business segment or geographical area;
- the loss of customers or key employees from the acquired businesses;
- the diversion of management’s attention from other existing business concerns;
- the failure to realize expected synergies and cost savings;
- difficulties in coordinating geographically disparate organizations, systems and facilities;
- difficulties in integrating personnel from diverse business backgrounds and organizational cultures; and
- difficulties in consolidating corporate and administrative functions.

The combined company may not be able to utilize a portion of Memorial’s or Range’s net operating loss carryforwards to offset future taxable income for U.S. federal tax purposes, which could adversely affect the combined company’s net income and cash flows. As noted in the financial statements included with this Form 10-K, we have substantial net operating losses (“NOLs”). Utilization of these NOLs depends on many factors, including the company’s future taxable income, which cannot be predicted with any accuracy. In addition, Section 382 of the Internal Revenue Code of 1986, as amended (“Section 382”), generally imposes an annual limitation on the amount of an NOL that may be used to offset taxable income when a corporation has undergone an “ownership change” (as determined under Section 382). An ownership change generally occurs if one or more stockholders (or groups of stockholders) change their ownership by more than 50 percentage points over their lowest ownership percentage within a rolling three-year period, taking into account for this purpose only those stockholders (or groups of stockholders) who are deemed to own at least 5% of the corporation’s stock. In the event that an ownership change has occurred—or were to occur—with respect to a corporation following its recognition of an NOL, utilization of this NOL would be subject to an annual limitation under Section 382, generally determined by multiplying the value of the corporation’s stock at the time of the ownership change by the applicable long-term tax-exempt rate as defined in Section 382. However, this annual limitation would be increased under certain circumstances by recognized built-in gains of the corporation existing at the time of the ownership change. Any unused annual limitation with respect to an NOL generally may be carried over to later years, subject to the expiration of the NOL 20 years after it arose.

If Range is determined to have undergone an ownership change in the future, we may be unable to fully utilize our NOLs prior to their expiration. To the extent we are not able to offset future taxable income with our NOLs, net income and cash flows may be adversely affected.

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

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

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

Our business could be negatively affected by security threats, including cybersecurity threats, and other disruptions. As a natural gas and oil producer, we face various security threats, including:

- cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable;
- threats to the security of our facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines; or
- threats from terrorist acts.

Computers and telecommunication systems are used to conduct our exploration, development and production activities and have become an integral part of our business. We use these systems to analyze and store financial and operating data and to communicate internally and with outside business partners. Cyber-attacks could compromise our computer and telecommunications systems and result in disruptions to our business operations or the loss of our data and proprietary information. In addition, computers control oil and gas production, processing equipment, and distribution systems globally and are necessary to deliver our production to market. A cyber-attack against these operating systems, or the networks and infrastructure on which they rely, could damage critical production, distribution and/or storage assets, delay or prevent delivery to markets, and make it difficult or impossible to accurately account for production and settle transactions.

Security threats have subjected our operations to increased risks that could have a material adverse effect on our business. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our personnel, information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to harm to our employees or losses of sensitive information, losses of critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, and results of operations or cash flows. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, ransomware, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign attacks, as well as military or other actions taken in response to these acts, could cause instability in the global financial and energy markets. Continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy in unpredictable ways, including the disruption of energy supplies and markets, increased volatility in commodity prices or the possibility that the infrastructure on which we rely could be a direct target or an indirect casualty of an act of terrorism, and, in turn, could materially and adversely affect our business and results of operations.

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

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

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

Higher natural gas, NGLs and oil prices generally stimulate demand for ancillary services. Similarly, lower natural gas, NGLs and oil prices generally result in a decline in service costs due to reduced demand for drilling and completion services. If the current market changes and commodity prices continue to recover, we may face shortages of field personnel, drilling rigs or other equipment and supplies which could delay or adversely affect our operations.

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

Risks Related to Our Common Stock

Common stockholders will be diluted if additional shares are issued. In 2014, we issued approximately 4.6 million shares of common stock in a public stock offering with the proceeds used to redeem our 8% senior subordinated notes due 2019. In 2016, we issued approximately 77.0 million shares as part of the MRD Merger. Our ability to repurchase securities for cash is limited by our bank credit facility. We also issue restricted stock and performance share units (and previously stock appreciation rights and stock options) to our employees and directors as part of their compensation. In addition, we may issue additional shares of common stock, additional subordinated notes or other securities or debt convertible into common stock, to extend maturities or fund capital expenditures, including acquisitions. If we issue additional shares of our common stock in the future, it may have a dilutive effect on our existing stockholders.

Dividend limitations. Limits on the payment of dividends and other restricted payments, as defined, are imposed under our bank credit facility. These limitations may, in certain circumstances, limit or prevent the payment of dividends.

Our stock price may be volatile and you may not be able to resell shares of our common stock at or above the price you paid. The price of our common stock fluctuates significantly, which may result in losses for investors. The market price of our common stock has been volatile. From January 1, 2015 to December 31, 2017, the price of our common stock reported by the New York Stock Exchange ranged from a low of $15.33 per share to a high of $65.53 per share. We expect our stock to continue to be subject to fluctuations as a result of a variety of factors, including factors beyond our control. These factors include:

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

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

Our certificate of incorporation, bylaws, some of our arrangements with employees and Delaware law contain provisions that could discourage an acquisition or change of control of us. Our certificate of incorporation and bylaws contain provisions that may make it more difficult to effect a change of control, to acquire us or to replace incumbent management, including, for example, limitations on shareholders' ability to remove directors, call special meetings and to propose and nominate directors or otherwise propose actions for approval at stockholder meetings, as well as the ability of our board of directors to amend our certificate of incorporation and bylaws and to issue and set the terms of preferred stock without the approval of our stockholders. In addition, our change of control severance plan, change of control severance agreements with certain officers and our omnibus stock plans and deferred compensation plans contain provisions that provide for severance payments and accelerated vesting of benefits, including accelerated vesting of equity awards and acceleration of deferred compensation, upon a change of control. Section 203 of the Delaware General Corporation Law also imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock. These provisions could discourage or prevent a change of control, even if it may be beneficial to our stockholders, or could reduce the price our stockholders receive in an acquisition of us.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

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

Environmental Proceedings

Our subsidiary, Range Resources – Appalachia, LLC, was notified by the Pennsylvania Department of Environmental Protection ("DEP") that it intends to assess a civil penalty under the Clean Streams Law and the 2012 Oil and Gas Act in connection with one well in Lycoming County. The DEP has directed us to prevent methane and other substances from escaping from this gas well into groundwater and a stream. We have considerable evidence that this well is not leaking and pre-drill testing of surrounding water wells showed the presence of methane in the water before commencement of our operations. While we intend to vigorously assert this position with the DEP, resolution of this matter may nonetheless result in monetary sanctions of more than $100,000.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Market for Common Stock

Our common stock is listed on the New York Stock Exchange ("NYSE") under the symbol "RRC". During 2017, trading volume averaged approximately 6.0 million shares per day. The following table shows the quarterly high and low sale prices and cash dividends declared as reported on the NYSE composite tape for the past two years.

	High	Low	Cash Dividends Declared
2016:			
First quarter	$ 36.86	$ 19.21	$ 0.02
Second quarter	46.96	31.11	0.02
Third quarter	45.76	36.58	0.02
Fourth quarter	40.20	31.20	0.02
2017:			
First quarter	$ 36.40	$ 26.61	$ 0.02
Second quarter	30.30	20.95	0.02
Third quarter	23.59	16.00	0.02
Fourth quarter	20.65	15.33	0.02

Between January 1, 2018 and February 20, 2018, our common stock traded at prices between $18.39 and $11.93 per share. Our senior notes and our senior subordinated notes are not listed on an exchange, but trade over-the-counter.

Holders of Record

Pursuant to the records of our transfer agent, as of February 20, 2018, there were approximately 1,008 holders of record of our common stock.

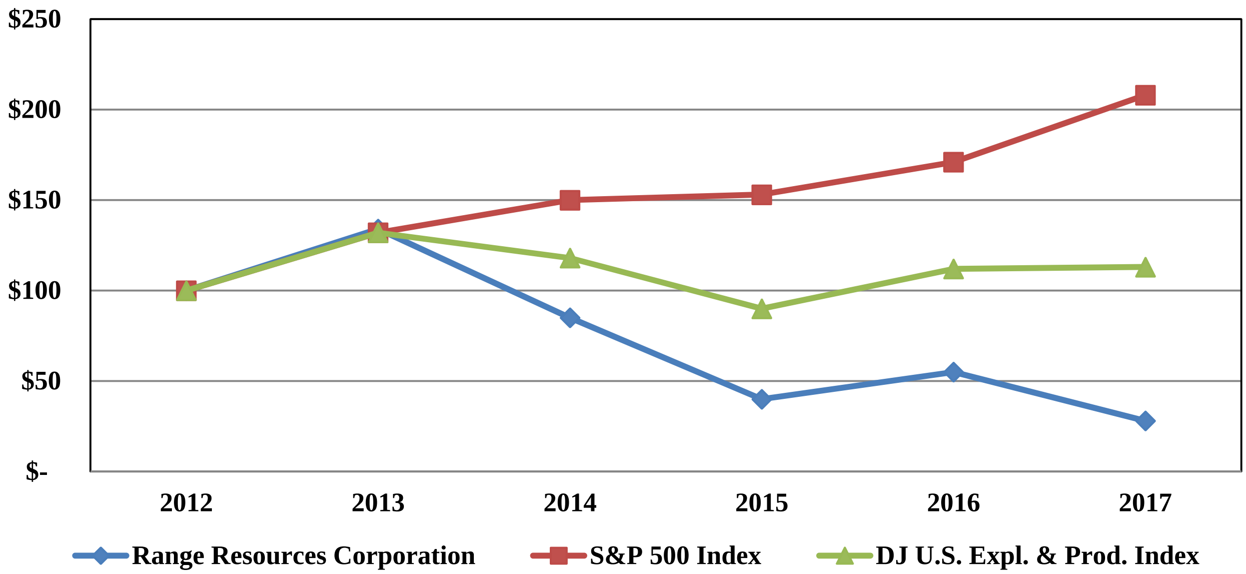
For information concerning shares authorized for issuance under equity compensation plans, see Note 13 to our consolidated financial statements.

Dividends

The payment of dividends is subject to declaration by the board of directors and depends on earnings, capital expenditures and various other factors. The board of directors declared quarterly dividends of $0.02 per common share for each of the four quarters of 2016 and 2017. The board of directors declared quarterly dividends of $0.04 per common share for each of the four quarters of 2015. The bank credit facility allows for the payment of common and preferred dividends, with certain limitations. The determination of the amount of future dividends, if any, to be declared and paid is at the sole discretion of our board of directors and will depend upon among other things, our earnings, financial condition, capital requirements, levels of indebtedness and other considerations our board of directors deems relevant. For more information, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Stockholder Return Performance Presentation*

The following graph is included in accordance with the SEC's executive compensation disclosure rules. This historic stock price performance is not necessarily indicative of future stock performance. The graph compares the change in the cumulative total return of Range's common stock, the Dow Jones U.S. Exploration and Production Index, and the S&P 500 Index for the five years ended December 31, 2017. The graph assumes that $100 was invested in the Company's common stock and each index on December 31, 2012 and that dividends were reinvested.



	2012	2013	2014	2015	2016	2017
Range Resources Corporation	$ 100	$ 134	$ 85	$ 40	$ 55	$ 28
S&P 500 Index	100	132	150	153	171	208
DJ U.S. Expl. & Prod. Index	100	132	118	90	112	113

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

ITEM 6. SELECTED FINANCIAL DATA AND PROVED RESERVE DATA

The following table shows selected financial information as of and for the five years ended December 31, 2017. Significant producing property acquisitions and dispositions may affect the comparability of year-to-year financial and operating data. In September 2016, we completed the MRD Merger. In first quarter 2016, we sold our non-operated interest in certain wells and gathering facilities in northeast Pennsylvania for cash proceeds of $111.5 million. In fourth quarter 2015, we sold the majority of our Virginia and West Virginia properties for cash proceeds of $876.0 million, before closing adjustments. In the first half of 2014, we completed the Conger Exchange where we sold our Conger properties located in Glasscock and Sterling Counties, Texas in exchange for producing properties and other assets in Virginia and $145.0 million in cash, before closing adjustments. In the first half of 2013, we sold certain Delaware and Permian Basin properties in Southeast New Mexico and West Texas for proceeds of $275.0 million. This information should be read in conjunction with Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, and our consolidated financial statements and related notes included elsewhere in this report (in thousands except per share or per mcfe data).

	Year Ended December 31,				
	2017	2016	2015	2014	2013
Statements of Operations Data:					
Natural gas, NGLs and oil sales	$ 2,176,287	$ 1,197,215	$ 1,089,644	$ 1,911,989	$ 1,715,676
Total revenues and other income	2,611,030	1,099,939	1,598,068	2,426,057	1,770,428
Total costs and expenses	2,528,910	1,902,077	2,650,430	1,395,172	1,620,849
Net income (loss)	333,146	(521,388)	(713,685)	634,382	115,722
Net income (loss) per share:					
–Basic	1.34	(2.75)	(4.29)	3.81	0.71
–Diluted	1.34	(2.75)	(4.29)	3.79	0.70
Costs per mcfe: [(a)]					
Direct operating expense	$ 0.18	$ 0.17	$ 0.27	$ 0.35	$ 0.37
Production and ad valorem tax expense	0.06	0.05	0.07	0.11	0.13
General and administrative expense	0.32	0.33	0.38	0.50	0.85
Interest expense	0.27	0.30	0.33	0.40	0.51
Depletion, depreciation and amortization expense	0.85	0.93	1.14	1.30	1.44
	$ 1.68	$ 1.78	$ 2.19	$ 2.66	$ 3.30
Average Daily Production:					
Natural gas (mcf)	1,343,160	1,026,807	993,662	786,099	724,735
NGLs (bbls)	97,834	76,026	55,770	51,563	25,356
Oil (bbls)	13,115	9,861	11,189	11,150	10,486
Total mcfe [(b)]	2,008,852	1,542,132	1,395,419	1,162,374	939,786
Balance Sheet Data:					
Current assets [(c)]	$ 429,234	$ 281,883	$ 439,074	$ 570,292	$ 196,887
Current liabilities [(d)]	755,473	702,653	351,720	639,677	495,561
Natural gas and oil properties, net	9,566,737	9,256,337	6,361,305	7,977,573	6,758,437
Total assets	11,728,841	11,282,245	6,900,031	8,704,604	7,203,127
Bank debt	1,208,467	876,428	86,427	713,221	495,683
Senior notes	2,851,754	2,848,591	738,101	—	—
Senior subordinated notes	48,585	48,498	1,826,775	2,317,603	2,600,288
Stockholders' equity	5,774,272	5,408,368	2,759,658	3,457,429	2,414,452
Weighted average diluted shares outstanding	245,458	189,868	166,389	164,403	161,407
Cash dividends declared per common share	0.08	0.08	0.16	0.16	0.16
Statements of Cash Flows Data:					
Net cash provided from operating activities	$ 816,254	$ 387,068	$ 691,402	$ 974,353	$ 757,373
Net cash used in investing activities	(1,139,057)	(308,835)	(218,772)	(1,245,456)	(983,436)
Net cash provided from (used in) financing activities	322,937	(78,390)	(472,607)	271,203	226,159
Proved Reserves Data (at end of period):					
Natural gas (Bcf)	10,264	7,870	6,278	6,923	5,666
NGLs (Mmbbls)	763	630	549	516	374
Oil and condensate (Mmbbls)	70	70	53	49	48
Total proved reserves (Bcfe)	15,262	12,072	9,892	10,310	8,202

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

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

(c) 2017 includes $58.6 million of derivative assets compared to $13.3 million in 2016, $281.5 million in 2015, $363.0 million in 2014 and $4.4 million in 2013.

(d) 2017 includes $44.2 million of derivative liabilities compared to $165.0 million in 2016, $1.1 million in 2015 and $26.2 million in 2013.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. The following discussion should be read in conjunction with the information under Item 8. Financial Statements and Supplementary Data and the other financial information found elsewhere in this Form 10-K. See also matters referenced in the foregoing pages under "Disclosures Regarding Forward-Looking Statements".

Overview of Our Business

We are an independent natural gas, natural gas liquids ("NGLs") and oil company engaged in the exploration, development and acquisition of natural gas and crude oil properties located primarily in the Appalachian and North Louisiana regions of the United States. We operate in one segment and have a single company-wide management team that administers all properties as a whole rather than by discrete operating segments. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis.

Our overarching business objective is to build stockholder value through returns − focused growth, on a per share debt-adjusted basis, of both reserves and production. Our strategy to achieve our business objective is to increase reserves and production through internally generated drilling projects occasionally coupled with complementary acquisitions and divestitures of non-core assets. Our revenues, profitability and future growth depend substantially on prevailing prices for natural gas, NGLs, crude oil and condensate and on our ability to economically find, develop, acquire and produce natural gas, NGLs and oil reserves. Looking ahead, our goal is to target annual production growth within operating cash flows. A further or extended decline in commodity prices could materially and adversely affect our business financial condition and results of operations. Prices for natural gas, NGLs and oil fluctuate widely and affect:

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

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

Sources of Our Revenues

We derive our revenues from the sale of natural gas, NGLs, oil and condensate that is produced from our properties. Revenues from product sales are a function of the volumes produced, prevailing market prices, product quality, gas Btu content and transportation costs. We generally sell natural gas, NGLs and oil under two types of agreements, which are common in our industry. Both types of agreements include transportation charges. One type of agreement is a netback agreement, under which we sell natural gas and oil at the wellhead and collect a price, net of transportation incurred by the purchaser. In this case, we record revenue at the price we receive from the purchaser. In the case of NGLs, we may receive a net price from the purchaser (which is net of processing costs) which is also recorded as revenue at the net price we receive from the purchaser. Under the other type of agreement, we sell natural gas, NGLs or oil at a specific delivery point, pay transportation to a third party and receive proceeds from the purchaser with no transportation deduction. In that case, we record transportation costs we pay to third parties as transportation, gathering, processing and compression expense. Cash settlements of derivative contracts are included in derivative fair value in the accompanying statements of operations. Brokered natural gas, marketing and other revenues include revenue we receive as a result of selling natural gas that is not our production (brokered), revenue from the release of transportation capacity where we have taken capacity ahead of our production and marketing fees we receive from third parties.

Principal Components of Our Cost Structure

- *Direct operating.* These are day-to-day costs incurred to bring hydrocarbons out of the ground along with the daily costs incurred to maintain our producing properties. Such costs include compensation of our field employees, maintenance, repairs and workover expenses related to our natural gas and oil properties. The majority of these costs are expected to remain a function of supply and demand. Direct operating expenses also include stock-based compensation expense (non-cash) associated with the amortization of equity grants as part of the compensation of field employees.
- *Transportation, gathering, processing and compression.* Under some of our sales arrangements, we sell natural gas and NGLs at a specific delivery point, pay transportation, gathering, processing and compression costs to a third party and

receive proceeds from the purchaser with no deduction. Transportation, gathering, processing and compression expense represents costs paid by Range to third parties under these arrangements.

- *Production and ad valorem taxes.* Production taxes are paid on produced natural gas and oil based on a percentage of sales revenue (excluding derivatives) or at fixed rates established by the applicable federal, state or local taxing authorities. In some states, ad valorem taxes are generally based on reserve values at the end of each year. In Louisiana, ad valorem tax assessments are based on capital costs, well age, depth and production. The Pennsylvania impact fee on unconventional natural gas and oil production, which includes the Marcellus Shale, is also included in this category.
- *Brokered natural gas and marketing.* These expenses are gas purchases for brokered natural gas that we buy and sell that is not our production plus overhead, including payroll and benefits for our marketing staff. These expenses also include costs related to transportation capacity we have taken ahead of our production. Brokered natural gas and marketing expenses also include stock-based compensation expense (non-cash) associated with the amortization of equity granted as part of our marketing staff compensation.
- *Exploration.* These are geological and geophysical costs, such as payroll and benefits for the geological and geophysical staff, seismic costs, delay rentals and the costs of unsuccessful exploratory dry holes. Exploration expenses also include stock-based compensation expense (non-cash) associated with the amortization of equity grants as part of the compensation of our exploration staff.
- *Abandonment and impairment of unproved properties.* This category includes unproved property impairment and expenses associated with oil and gas lease expirations. Impairment on a majority of our unproved properties is assessed and amortized on an aggregate basis based on average holding period, expected forfeiture rate and anticipated drilling success.
- *General and administrative.* These costs include overhead, such as payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, audit and other professional fees, legal compliance and legal settlements. Included in this category are overhead expense reimbursements we receive from working interest owners of properties, for which we serve as the operator. These reimbursements are received during both the drilling and operational stages of a property's life. General and administrative expenses also include stock-based compensation expense (non-cash) associated with the amortization of equity grants as part of the compensation of our corporate staff and our directors.
- *Deferred compensation plan.* These costs relate to the increase or decrease in the value of the liability associated with our deferred compensation plan. Our deferred compensation plan gives directors, officers and key employees the ability to defer all or a portion of their salaries and bonuses and invest in our common stock or make other investments at the individual's discretion. The assets of this plan are held in a grantor trust, are funded on the grant date and are available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. We do not maintain a defined benefit retirement plan for any of our employees. However, in fourth quarter 2017, we implemented a succession plan enhancement for officers which includes a post-retirement benefit plan to assist in providing health care to officers who are active employees and have met certain age and service requirements. These benefits are provided up to age 65 or at the date they become eligible for Medicare.
- *Interest.* We have typically financed a portion of our cash requirements with borrowings under our bank credit facility and with longer-term debt securities. Also, included are administrative fees associated with our bank credit facility and the amortization of deferred financing costs. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We currently have no capitalized interest.
- *Depreciation, depletion and amortization.* This includes the systematic expensing of the capitalized costs incurred to acquire, explore and develop natural gas, NGLs and oil. As a successful efforts company, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts, and apportion these costs to each unit of production through depreciation, depletion and amortization expense. This expense also includes the systematic, monthly accretion of the future abandonment costs of tangible assets such as wells, service assets, pipelines, and other facilities.
- *Income taxes.* We are subject to state and federal income taxes but are currently not in a cash taxpaying position for federal income taxes, primarily due to the current deductibility and/or accelerated amortization of intangible drilling costs ("IDC"). At this time, we generally do not pay significant state income taxes due to our state net operating loss carryovers and our ability to follow the federal treatment of deducting IDC in most of the states in which we operate. Currently, all of our federal taxes are deferred. We have federal valuation allowances of $31.3 million and state valuation allowances of $93.8 million. For more information, see Item 1A. Risk Factors-*Certain federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated and additional state taxes on natural gas extraction may be imposed, as a result of future legislation*.

Management's Discussion and Analysis of Results of Operations

While operating in an improving price environment for natural gas, NGLs and oil prices, we had many operational, financial and strategic successes in 2017. During 2017, we continued our efforts on operating cost management, simplifying our portfolio and maintaining liquidity. We believe we have positioned ourselves for long-term operational performance and future growth. In summary, we exited 2017 with operational momentum, investment flexibility and strong financial liquidity which we expect to carry over to 2018.

Overview of 2017 Results

During 2017, we achieved the following financial and operating performance results:

- average realized prices improved 12% from 2016;
- 30% production growth from 2016;
- achieved 26% annual proved reserve growth;
- drilled 164 net wells with a 99% success rate;
- continued expansion of our activities in the Marcellus Shale by growing production, proving up acreage and acquiring additional unproved acreage;
- reduced general and administrative expenses per mcfe 3% from 2016;
- reduced interest expense per mcfe 10% from 2016;
- reduced our DD&A rate per mcfe 9% from 2016;
- achieved a debt per mcfe of proved reserves of $0.27 compared to $0.32 in 2016;
- entered into additional commodity-based derivative contracts for 2018 and 2019;
- received $71.2 million of proceeds, before closing adjustments, from the sale of producing properties in Texas and Oklahoma and $1.3 million of proceeds from the sale of miscellaneous non-core oil and gas assets;
- continued to enter into new marketing agreements to improve our realized prices;
- realized $816.3 million of cash flow from operating activities; and
- ended the year with stockholders' equity of $5.8 billion.

Operationally, in 2017 we continued to focus on operational flexibility, efficiencies and controlling costs. As evidenced by history and our current industry environment, the prices at which we sell our production are volatile and we have little control over them. Therefore, to improve our profitability, we focus our efforts on improving operating efficiency. We continue to focus on material reductions in unit costs. As reservoirs are depleted and production rates decline, per unit production costs will generally increase. To lessen this effect, we concentrate our production in core areas where we can achieve economies of scale to help manage our operating costs.

Acquisitions

During 2017, we spent $62.1 million to acquire unproved acreage compared to $33.1 million in 2016 and $73.0 million in 2015. We continue selective acreage leasing and lease renewals to add to our acreage positions in both the Marcellus Shale play in Pennsylvania and North Louisiana.

During 2016, we completed our merger with Memorial through the issuance of 77.0 million shares of Range common stock in exchange for all outstanding shares of Memorial and the assumption of $1.2 billion of debt. This merger added another onshore U.S. natural gas resource play to our existing core operating areas. We believe the North Louisiana location provides geographic and marketing diversity to our high quality Appalachia basin assets.

Divestitures

Texas. In 2017, we sold various properties for proceeds of $40.4 million and we recognized a loss of $989,000, after closing adjustments. In February 2015, we sold our remaining West Texas properties for cash proceeds of $10.5 million and we recognized a loss of $101,000.

Oklahoma. In 2017, we sold various properties in Western Oklahoma for proceeds of $30.8 million and we recognized a gain of $23.8 million, after closing adjustments. In 2016, we sold certain properties in Western Oklahoma for proceeds of $78.6 million and we recorded a loss of $5.3 related to these sales, after closing adjustments and transaction fees.

Pennsylvania. In first quarter 2016, we sold our non-operated interest in certain wells and gathering facilities in northeast Pennsylvania for proceeds of $111.5 million and we recorded a loss of $2.1 million, after closing adjustments. In June 2015, we sold miscellaneous unproved properties for proceeds of $3.4 million and we recognized a loss of $2.9 million.

Virginia and West Virginia. In December 2015, we sold the majority of our producing properties and gathering assets in Virginia and West Virginia for cash proceeds of $876.0 million, before closing adjustments. We closed the transaction at the end of December 2015 and recognized a pretax loss of $407.7 million related to this sale.

2018 Outlook

As we enter 2018, we believe we are positioned for sustainability, operational efficiency and long-term success. However, if the industry downturn continues for an extended period or becomes more severe, we could experience additional negative impacts on our revenues, profitability, cash flows, liquidity and proved reserves. For 2018, the board of directors approved a $941.2 million capital budget for natural gas, NGLs, crude oil and condensate related activities, excluding proved property acquisitions, for which we do not budget. Our 2018 capital budget will be approximately 85% allocated to our Appalachian division. 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. We also expect our 2018 capital budget to achieve production growth of an estimated 11% and we intend to limit capital spending to at or below cash flow. Our 2018 capital budget is designed to focus on improving corporate returns. To the extent our 2018 capital requirements exceed our internally generated cash flow and proceeds from asset sales, we may draw on our committed capacity under our bank credit facility and issue additional debt or equity 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 2018 is mitigated using commodity derivative contracts and we intend to continue to enter into these transactions. We believe it is likely commodity prices will continue to be volatile during 2018.

Market Conditions

Prices for various quantities of natural gas, NGLs and oil that we produce significantly impact our revenues and cash flows. Prices for commodities, such as hydrocarbons, are inherently volatile. Over the last several years, natural gas and crude oil prices have been depressed with a slight rebound in 2017. Recently, natural gas prices have improved with the average NYMEX monthly settlement price for natural gas increasing to $3.63 per mcf for February 2018 and crude oil rising to $63.66 per barrel in January 2018. The following table lists average NYMEX prices for natural gas and oil and the Mont Belvieu NGL composite price for the years ended December 31, 2017, 2016 and 2015.

	Year Ended December 31,		
	2017	2016	2015
Average NYMEX prices [(a)]			
Natural gas (per mcf)	$ 3.10	$ 2.51	$ 2.65
Oil (per bbl)	$ 51.07	$ 43.69	$ 49.21
Mont Belvieu NGL composite (per gallon)	$ 0.56	$ 0.41	$ 0.40

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

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

Our revenues vary from year to year as a result of changes in realized commodity prices and production volumes. For more information, see *"Sources of Our Revenues"* above. In 2017, natural gas, NGLs and oil sales increased 82% from 2016 with a 30% increase in production and a 40% increase in realized prices. In 2016, natural gas, NGLs and oil sales increased 10% from 2015 with an 11% increase in production partially offset by a 14% decrease in realized prices. The following table illustrates the primary components of natural gas, NGLs, crude oil and condensate sales for each of the last three years (in thousands):

	2017	2016	2015
Natural gas, NGLs and Oil sales			
Natural gas	$ 1,349,965	$ 753,888	$ 773,093
NGLs	604,672	318,462	176,546
Oil and condensate	221,650	124,865	140,005
Total natural gas, NGLs and oil sales	$ 2,176,287	$ 1,197,215	$ 1,089,644

Our production continues to grow through drilling success as we place new wells on production and acquisitions partially offset the natural decline of our natural gas and oil reserves through production and non-core asset sales. For 2017, our production increased

16% in our Appalachian region when compared to 2016. For 2016, our production increased 4% in our Appalachian region when compared to 2015, despite the sale of our Virginia/West Virginia properties at the end of 2015. Production from our newly acquired North Louisiana properties was 138.7 Bcfe in 2017 compared to 43.6 Bcfe in 2016. Our production for each of the last three years is set forth in the following table:

	2017	2016	2015
Production [(a)]			
Natural gas (mcf)	490,253,467	375,811,462	362,686,707
NGLs (bbls)	35,709,254	27,825,635	20,356,110
Crude oil and condensate (bbls)	4,787,022	3,609,171	4,084,069
Total (mcfe) [(b)]	733,231,123	564,420,298	509,327,781
Average daily production [(a)]			
Natural gas (mcf)	1,343,160	1,026,807	993,662
NGLs (bbls)	97,834	76,026	55,770
Crude oil and condensate (bbls)	13,115	9,861	11,189
Total (mcfe) [(b)]	2,008,852	1,542,132	1,395,419

(a) Represents volumes sold regardless of when produced.

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

Our average realized price (including all derivative settlements and third-party transportation costs paid by Range) received during 2017 was $1.95 per mcfe compared to $1.74 per mcfe in 2016 and $2.41 per mcfe in 2015. Because we record transportation costs on two separate bases, as required by U.S. GAAP, we believe computed final realized prices should include the impact of transportation, gathering, processing and compression expense. Average sales prices (excluding derivative settlements) do not include any derivative settlements or third party transportation costs which are reported in transportation, gathering and compression expense on the accompanying consolidated statements of operations. Average sales prices (excluding derivative settlements) do include transportation costs where we receive net proceeds from the purchaser. Our average realized price (including all derivative settlements and third-party transportation costs paid by Range) calculation includes all cash settlements for derivatives. Average realized price calculations for each of the last three years are shown below:

	2017	2016	2015
Average Prices			
Average sales prices (excluding derivative settlements):			
Natural gas (per mcf)	$ 2.75	$ 2.01	$ 2.13
NGLs (per bbl)	16.93	11.44	8.67
Crude oil (per bbl)	46.30	34.60	34.28
Total (per mcfe) [(a)]	2.97	2.12	2.14
Average realized prices (including all derivative settlements):			
Natural gas (per mcf)	$ 2.90	$ 2.68	$ 3.07
NGLs (per bbl)	14.88	13.16	10.73
Crude oil (per bbl)	49.49	47.82	71.28
Total (per mcfe) [(a)]	2.99	2.74	3.18
Average realized prices (including all derivative settlements and third party transportation costs paid by Range):			
Natural gas (per mcf)	$ 1.82	$ 1.60	$ 2.12
NGLs (per bbl)	8.32	7.33	8.12
Crude oil (per bbl)	49.49	47.82	71.28
Total (per mcfe) [(a)]	1.95	1.74	2.41

(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.

Transportation, gathering, processing and compression expense was $761.2 million in 2017 compared to $565.2 million in 2016 and $396.7 million in 2015. These third party costs are higher in each year due to our production growth in the Marcellus Shale where we have third party gathering, compression, processing and transportation agreements. The year ended December 31, 2017 includes additional third party costs for our newly acquired North Louisiana production for the entire year. The year ended December 31, 2016 includes additional expenses related to the commencement of a new NGLs pipeline project where we are able to sell both ethane and propane for export internationally and additional ethane pipeline capacity charges for ethane transportation to the Gulf Coast. We have included these costs in the calculation of average realized prices (including all derivative settlements and third party transportation expenses paid by Range). The following table summarizes transportation, gathering, processing and compression expense for each of the last three years (in thousands) and on a per mcf and per barrel basis:

	2017	2016	2015
Natural gas	$ 526,671	$ 403,209	$ 343,593
NGLs	234,512	162,000	53,146
Total	$ 761,183	$ 565,209	$ 396,739
Natural gas (per mcf)	$ 1.07	$ 1.07	$ 0.95
NGLs (per bbl)	$ 6.57	$ 5.82	$ 2.61

Derivative fair value income (loss) was income of $213.4 million in 2017 compared to a loss of $261.4 million in 2016 and income of $416.4 million in 2015. All of our derivatives are accounted for using the mark-to-market accounting method. Mark-to-market accounting treatment creates volatility in our revenues as unrealized gains and losses from derivatives are included in total revenues. As commodity prices increase or decrease, such changes will have an opposite effect on the mark-to-market value of our derivatives. Gains on our derivatives generally indicate lower wellhead revenues in the future while losses indicate higher future wellhead revenues. At December 31, 2017, our commodity derivative contracts were recorded at their fair value, which was a net derivative asset of $13.6 million, an increase of $200.8 million from the $187.2 million net derivative liability recorded as of December 31, 2016. We have also entered into basis swap agreements to limit volatility caused by changing differentials between NYMEX and regional prices received. These basis swaps are marked to market and we recognized a net derivative liability of $7.8 million as of December 31, 2017 compared to a net derivative asset of $11.8 million as of December 31, 2016. As of December 31, 2016, we have propane basis swaps to limit the volatility caused by changing differentials between Mont Belvieu and international propane indexes which is recognized as a net derivative liability of $1.2 million as of December 31, 2017 compared to a net derivative liability of $742,000 as of December 31, 2016. In connection with our international propane swaps, we also have freight swap contracts which lock in the freight rate for a specific trade route on the Baltic exchange which is recognized as a net derivative asset of $276,000 compared to a net derivative asset of $65,000 as of December 31, 2016. The following table summarizes the impact of our commodity derivatives for each of the last three years (in thousands):

	2017	2016	2015
Derivative fair value income (loss) per consolidated statements of operations	$ 213,350	$ (261,391)	$ 416,364
Non-cash fair value gain (loss): (1)			
Natural gas derivatives	$ 221,251	$ (415,833)	$ (43,310)
Oil derivatives	(20,874)	(30,363)	(89,880)
NGLs derivatives	(355)	(149,982)	17,432
Freight derivatives	211	(12,549)	—
Total non-cash fair value gain (loss) (1)	$ 200,233	$ (608,727)	$ (115,758)
Net cash receipt (payment) on derivative settlements:			
Natural gas derivatives	$ 71,059	$ 252,000	$ 339,031
Oil derivatives	15,250	47,710	151,117
NGLs derivatives	(73,192)	47,626	41,974
Total net cash receipt (payment)	$ 13,117	$ 347,336	$ 532,122

(1) Non-cash fair value adjustments on commodity derivatives is a non-GAAP measure. Non-cash fair value adjustments on commodity derivatives only represent the net change between periods of the fair market values of commodity derivative positions and exclude the impact of settlements on commodity derivatives during the period. We believe that non-cash fair value adjustments on commodity derivatives is a useful supplemental disclosure to differentiate non-cash fair market value adjustments from settlements on commodity derivatives during the period. Non-cash fair value adjustments on commodity derivatives is not a measure of financial or operating performance under GAAP, nor should it be considered a substitute for derivative fair value income or loss as reported in our consolidated statements of operations.

Brokered natural gas, marketing and other revenue was $221.4 million in 2017 compared to $164.1 million in 2016 and $92.1 million in 2015. The 2017 period includes $219.5 million of revenue primarily from the sale of natural gas that is not related to our production. These revenues increased from 2016 due to higher brokered natural gas volumes and higher sales prices. The 2016 period includes $163.2 million of revenue primarily from the sale of natural gas that is not related to our production (brokered). These revenues increased from 2015 due to significantly higher brokered natural gas volumes and higher sales prices. The 2015 period includes $90.9 million of revenue from the sale of natural gas that is not related to our production (brokered).

Costs and Expenses per mcfe

We believe some of our expense fluctuations are best analyzed on a unit-of-production, or per mcfe, basis. The following presents information about certain of our expenses on a per mcfe basis for each of the last three years:

	Year Ended December 31,				Year Ended December 31,			
	2017	2016	Change	% Change	2016	2015	Change	% Change
Direct operating expense	$ 0.18	$0.17	$ 0.01	6%	$ 0.17	$ 0.27	$ (0.10)	(37%)
Production and ad valorem tax expense	0.06	0.05	0.01	20%	0.05	0.07	(0.02)	(29%)
General and administrative expense	0.32	0.33	(0.01)	(3%)	0.33	0.38	(0.05)	(13%)
Interest expense	0.27	0.30	(0.03)	(10%)	0.30	0.33	(0.03)	(9%)
Depletion, depreciation and amortization expense	0.85	0.93	(0.08)	(9%)	0.93	1.14	(0.21)	(18%)

Direct operating expense was $134.3 million in 2017 compared to $97.4 million in 2016 and $136.4 million in 2015. We experience increases in operating expenses as we add new wells and manage existing properties. Direct operating expenses include normally recurring expenses to operate and produce our wells, non-recurring workovers and repair-related expenses. On an absolute basis, our direct operating expenses for 2017 increased 38% from prior year primarily due to our newly acquired North Louisiana properties partially offset by our continuing cost reduction efforts. We experienced cost increases in many categories of direct operating expenses including personnel costs, well service costs, water handling and disposal costs and workovers. On an absolute basis, our direct operating expenses for 2016 decreased 29% from the prior year with lower water handling costs due, in part, to our water recycling efforts, lower workover costs, lower well service costs, lower field personnel and stock-based compensation expenses and the sale of certain non-core assets. We incurred $10.5 million of workover costs in 2017 compared to $4.5 million of workover costs in 2016 and $7.3 million in 2015.

On a per mcfe basis, operating expense for 2017 increased $0.01, or 6%, from the same period of 2016, with the increase consisting of higher water handling and equipment leasing costs. On a per mcfe basis, operating expense for 2016 decreased $0.10, or 37%, from the same period of 2015, with the decrease consisting of lower water handling costs, lower well services, lower field personnel costs and stock-based compensation. We have experienced lower costs per mcfe as we have increased production from our Marcellus Shale wells due to their lower operating cost relative to our other operating areas. Stock-based compensation expense represents the amortization of equity grants as part of the compensation of field employees. The following table summarizes direct operating expenses per mcfe for each of the last three years:

	Year Ended December 31,				Year Ended December 31,			
	2017	2016	Change	% Change	2016	2015	Change	% Change
Lease operating expense	$0.17	$0.16	$ 0.01	6%	$0.16	$ 0.25	$ (0.09)	(36%)
Workovers	0.01	0.01	—	—%	0.01	0.01	—	—%
Stock-based compensation (non-cash)	—	—	—	—%	—	0.01	(0.01)	(100%)
Total direct operating expense	$0.18	$0.17	$ 0.01	6%	$0.17	$ 0.27	$ (0.10)	(37%)

Production and ad valorem taxes are paid based on market prices, not hedged prices. This expense category also includes the Pennsylvania impact fee. In February 2012, the Commonwealth of Pennsylvania enacted an "impact fee" on unconventional natural gas and oil production which includes the Marcellus Shale. The impact fee is based upon the year wells are drilled and the fee varies, like a severance tax, based upon natural gas prices. The year ended December 31, 2017 includes a $30.9 million ($0.04 per mcfe) impact fee compared to $22.5 million ($0.04 per mcfe) in the year ended December 31, 2016 with an increase in wells drilled in Pennsylvania and higher prices. Production and ad valorem taxes (excluding the impact fee) were $11.9 million in 2017 compared to $2.9 million in 2016 primarily due to our newly acquired North Louisiana properties. On a per mcfe basis, production and ad valorem taxes (excluding the impact fee) was $0.02 in 2017 compared to $0.01 in 2016 due to an increase in production volumes subject to production and ad valorem taxes and higher prices. The year ended December 31, 2016 includes a $22.5 million ($0.04 per mcfe) impact fee compared to a $23.7 million ($0.05 per mcfe) impact fee in the year ended December 31, 2015. Production and ad valorem taxes (excluding the impact fee) were $2.9 million in 2016 compared to $10.1 million in 2015. On a per mcfe basis, production and ad valorem taxes (excluding the impact fee) decreased to $0.01 in 2016 compared to $0.02 in 2015 due to an increase in production volumes not subject to production or ad valorem taxes.

General and administrative expense was $233.4 million for 2017 compared to $184.8 million for 2016 and $194.0 million in 2015. The increase in 2017, when compared to 2016, is primarily due to higher stock-based compensation of $30.2 million resulting from accelerated vesting of equity awards related to a one-time implementation of a succession plan enhancement for officers, higher salaries and benefits of $7.6 million, higher legal costs (including settlements) of $5.0 million and higher Louisiana franchise taxes of $4.2 million. The decrease in 2016, when compared to 2015, is primarily due to lower salaries and benefits of $6.1 million, lower legal expenses (including fines) of $2.0 million, lower bad debt expense of $1.5 million and lower public relations costs and consulting fees partially offset by higher Louisiana franchise taxes of $1.9 million. Stock-based compensation expense represents the amortization of stock-based compensation awards granted to our employees and directors as part of their compensation. The following table summarizes general and administrative expenses per mcfe for each of the last three years:

	Year Ended December 31,				Year Ended December 31,			
	2017	2016	Change	% Change	2016	2015	Change	% Change
General and administrative	$ 0.22	$ 0.24	$ (0.02)	(8%)	$ 0.24	$ 0.28	$ (0.04)	(14%)
Stock-based compensation (non-cash)	0.10	0.09	0.01	11%	0.09	0.10	(0.01)	(10%)
Total general and administrative expense	$ 0.32	$ 0.33	$ (0.01)	(3%)	$ 0.33	$ 0.38	$ (0.05)	(13%)

Interest expense was $195.7 million for 2017 compared to $168.2 million for 2016 and $166.4 million in 2015. The following table presents information about interest expense per mcfe for each of the last three years:

	Year Ended December 31,		
	2017	2016	2015
Bank credit facility	$ 0.05	$ 0.02	$ 0.04
Senior notes	0.20	0.12	0.05
Senior subordinated notes	0.01	0.13	0.23
Senior note exchange	—	0.01	—
Amortization of deferred financing costs and other	0.01	0.02	0.01
Total interest expense	$ 0.27	$ 0.30	$ 0.33
Average debt outstanding (in thousands)	$ 3,960,994	$ 3,052,666	$ 3,467,175
Average interest rate [(a)]	4.8%	5.1%	4.6%

[(a)] Includes commitment fees but excludes amortization of debt issue costs and amortization of discount.

On an absolute basis, the increase in interest expense for 2017 from the same period of 2016 was primarily due to higher average outstanding debt balances partially offset by lower average interest rates. On an absolute basis, the increase in interest expense for 2016 from the same period of 2015 was primarily due to higher average interest rates somewhat offset by lower average debt balances. Interest expense in 2016 includes an additional $6.6 million of transaction costs associated with our senior subordinated note exchange. See Note 8 to our consolidated financial statements for additional information. In July 2015, we redeemed all $500.0 million of our 6.75% senior subordinated notes due 2020 (the “6.75% Notes”). In May 2015, we issued $750.0 million of 4.875% senior notes due 2025. We used the proceeds for general corporate purposes and our redemption of our 6.75% notes. Interest expense in 2015 includes interest incurred for both the 6.75% Notes and the 4.875% senior notes due 2025 for two months. Average debt outstanding on the bank credit facility for 2017 was $1.0 billion compared to $356.6 million for 2016 and $847.8 million for 2015 and the weighted average interest rate on the bank credit facility was 2.7% for 2017 compared to 2.2% in 2016 and 1.7% in 2015.

Depletion, depreciation and amortization (“DD&A”) was $625.0 million in 2017 compared to $524.1 million in 2016 and $581.2 million in 2015. The increase in 2017 when compared to 2016 is due to a 30% increase in production volumes somewhat offset by a 7% decrease in depletion rates. The decrease in 2016 when compared to 2015 is due to a 19% decrease in depletion rates somewhat offset by an 11% increase in production volumes.

On a per mcfe basis, DD&A decreased to $0.85 in 2017 compared to $0.93 in 2016 and $1.14 in 2015. Depletion expense, the largest component of DD&A, was $0.82 per mcfe in 2017 compared to $0.88 per mcfe in 2016 and $1.08 per mcfe in 2015. We have historically adjusted our depletion rates in the fourth quarter of each year based on the year-end reserve report and other times during the year when circumstances indicate there has been a significant change in reserves or costs. We currently expect our DD&A rate to be approximately $0.80 per mcfe in 2018, based on our current production estimates. In areas where we are actively drilling, such as the Marcellus Shale area, our fourth quarter adjusted 2017 depletion rates were lower than the fourth quarter 2016 and 2015 depletion rates. Depletion rates in new plays tend to be higher in the beginning as increased initial outlays are amortized over proved reserves based on early stages of evaluations. The decrease in DD&A per mcfe in 2017 when compared to 2016 and 2015 is due to the mix of our production from our properties with lower depletion rates. The following table summarizes DD&A expenses per mcfe for each of the last three years:

	Year Ended December 31,				Year Ended December 31,			
	2017	2016	Change	% Change	2016	2015	Change	% Change
Depletion and amortization	$0.82	$0.88	$ (0.06)	(7%)	$0.88	$1.08	$ (0.20)	(19%)
Depreciation	0.01	0.02	(0.01)	(50%)	0.02	0.02	—	—%
Accretion and other	0.02	0.03	(0.01)	(33%)	0.03	0.04	(0.01)	(25%)
Total DD&A expenses	$0.85	$0.93	$ (0.08)	(9%)	$0.93	$1.14	$ (0.21)	(18%)

Other Operating Expenses

Our total operating expenses also include other expenses that generally do not trend with production. These expenses include stock-based compensation, brokered natural gas and marketing, exploration expense, abandonment and impairment of unproved properties, MRD Merger expenses, termination costs, deferred compensation plan expenses, loss on early extinguishment of debt and impairment of proved properties.

The following table details stock-based compensation that is allocated to functional expense categories for each of the years in the three-year period ended December 31, 2017 (in thousands):

	2017	2016	2015
Direct operating expense	$ 2,060	$ 2,302	$ 2,780
Brokered natural gas and marketing expense	1,437	1,725	2,132
Exploration expense	2,128	2,298	2,985
Exploration expense – one-time acceleration	614	—	—
General and administrative expense	44,659	49,293	49,687
General and administrative expense – one-time acceleration	30,214	—	—
Termination costs	1,664	—	217
Total stock-based compensation	$ 82,776	$ 55,618	$ 57,801

Stock-based compensation includes the amortization of restricted stock grants, SARs and PSUs grants. The year ended 2017 includes $30.8 million in increased stock-based compensation due to accelerated vesting of existing equity awards related to the one-time implementation of a succession plan enhancement for officers.

Brokered natural gas and marketing expense was $220.3 million in 2017 compared to $168.6 million in 2016 and $115.9 million in 2015. The increase in these costs reflects significantly higher broker purchase volumes and higher purchase prices. The increase in these costs from 2015 to 2016 reflects higher brokered natural gas volumes and higher purchase prices somewhat offset by lower operating expenses related to company-owned gathering lines (which we sold in fourth quarter 2015). Stock-based compensation represents the amortization of equity stock grants as part of the compensation of our marketing staff.

Exploration expense was $53.7 million in 2017 compared to $32.3 million in 2016 and $21.4 million in 2015. Exploration expense was higher due to higher dry hole costs, higher seismic and delay rental costs. Exploration expense was higher in 2016 when compared to 2015 due to higher seismic costs and higher delay rentals. Stock-based compensation represents the amortization of equity stock grants as part of the compensation of our exploration staff. The following table details our exploration related expenses for each of the years in the three-year period ended December 31, 2017 (in thousands):

	Year Ended December 31,				Year Ended December 31,			
	2017	2016	Change	% Change	2016	2015	Change	% Change
Seismic	$ 15,191	$ 9,793	$ 5,398	55%	$ 9,793	$ 1,731	$ 8,062	466%
Delay rentals and other	14,658	9,489	5,169	54%	9,489	4,709	4,780	102%
Personnel expense	11,899	10,727	1,172	11%	10,727	11,894	(1,167)	(10%)
Stock-based compensation expense	2,742	2,298	444	19%	2,298	2,985	(687)	(23%)
Exploratory dry hole expense	9,172	18	9,154	—%	18	87	(69)	(79%)
Total exploration expense	$ 53,662	$ 32,325	$ 21,337	66%	$ 32,325	$ 21,406	$ 10,919	51%

Abandonment and impairment of unproved properties was $269.7 million in 2017 compared to $30.1 million in 2016 and $47.6 million in 2015. We assess individually significant unproved properties for impairment on a quarterly basis and recognize a loss where circumstances indicate impairment in value. In determining whether a significant unproved property is impaired we consider numerous factors including, but not limited to, current exploration plans, favorable or unfavorable activity on the property being evaluated and/or adjacent properties, our geologists' evaluation of the property and the remaining months in the lease term for the property. Impairment of individually insignificant unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. The increase in abandonment expense reflects additional expected lease expirations in North Louisiana. As we continue to review our acreage positions and high grade our drilling inventory based on the current price environment, additional leasehold impairments and abandonments will likely be recorded.

Memorial Merger expenses of $37.2 million in 2016 include amounts paid in connection with the merger with Memorial including consulting, investment banking, advisory, legal and other merger-related fees. There were no MRD Merger expenses in 2017.

Termination costs in 2017 includes an additional $4.0 million as we implemented additional work force reductions with $2.2 million for estimated severance costs and $1.7 million of accelerated vesting of equity grants. Termination costs in 2016 include additional accrued leasing costs related to the closing of our Oklahoma City offices more than offset by favorable severance adjustments. Termination costs in 2015 include $3.1 million of accrued building lease costs for our Oklahoma City office which was closed in the first half of 2015, additional severance of $11.7 million and stock-based compensation of $217,000 for accelerated vesting of equity grants for our Oklahoma City office employees and other areas where we determined a need to reduce personnel due, in part, to the lower commodity price environment.

Deferred compensation plan expense was a gain of $50.9 million in 2017 compared to a loss of $19.2 million in 2016 and a gain of $77.6 million in 2015. Our stock price decreased to $17.06 at December 31, 2017 from $34.36 at December 31, 2016. Our stock price increased to $34.36 at December 31, 2016 from $24.61 at December 31, 2015. This non-cash item relates to the increase or decrease in value of the liability associated with our common stock that is vested and held in our deferred compensation plan. The deferred compensation liability is adjusted to fair value by a charge or a credit to deferred compensation plan expense. Common shares are placed in the deferred compensation plan when granted.

Loss on early extinguishment of debt was $22.5 million in 2015. In August 2015, we redeemed our 6.75% senior subordinated notes due 2020 at 103.375% of par and we recorded a loss on extinguishment of debt of $22.5 million, which includes a call premium and expensing of deferred financing costs on the repurchased debt. There was no loss on extinguishment of debt in 2016 or 2017.

Impairment of proved properties increased to $63.7 million in 2017 compared to $43.0 million in 2016 and $590.2 million in 2015. In 2017, we recorded impairment expense related to certain of our oil and gas properties in Oklahoma and the Texas Panhandle. These assets were evaluated for impairment due to the possibility of sale. In 2016, we recorded impairment expense related to certain of our oil and gas properties in Western Oklahoma. These assets were evaluated for impairment due to commodity prices and the possibility of sale. Due to a significant decline in commodity prices in 2015, we recorded $306.6 million of impairment charges related to our oil and natural gas properties in Northern Oklahoma, $195.6 million related to our legacy shallow producing assets in Northwest Pennsylvania, $86.9 million related to oil and natural gas properties in the Texas Panhandle and $1.1 million related to assets in South Texas in the year ended December 31, 2015. These assets were evaluated for impairment due to declining reserves, natural gas and oil prices and changes in projected capital spending and, in the case of certain of our North Texas and West Texas properties, the possibility of a sale. The cash flows we use to assess proved property impairment include numerous assumptions including (1) future reserve adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves, (2) results of future drilling activities, (3) future commodity prices and (4) increases or decreases in production and capital costs. All inputs are evaluated at each measurement date.

Income tax benefit was $251.0 million in 2017 compared to $280.8 million in 2016 and $338.7 million in 2015. The 2017 decrease in our income tax benefit reflects a $884.3 million improvement in income before income taxes more than offset by the Tax Cuts and Jobs Act of 2017, as described more fully below. The 2016 increase in income taxes reflects a $250.2 million improvement in loss before income taxes when compared to the same period of 2015. The effective tax rate was a negative 305.7% in 2017 compared to 35.0% in 2016 and 32.2% in 2015. The 2017, 2016 and 2015 effective tax rates were different than the statutory tax rate due to the Tax Cuts and Jobs Act of 2017 (as more fully described below), state income taxes and other discrete tax items which are detailed below. For each of the three years ended December 31, 2017, 2016 and, 2015, current income tax expense relates to state income taxes.

The Tax Cuts and Jobs Act of 2017 was signed into law on December 22, 2017. The new law significantly reforms the Internal Revenue Code of 1986, as amended. The reduction in the corporate tax rate required a one-time revaluation of certain tax-related assets and liabilities to reflect their value at the lower corporate tax rate of 21%. We reviewed all of the valuation allowances previously established at the old corporate tax rate of 35% to reflect the appropriate new balances after the enactment of the new law. The one-time tax benefit recorded related to the tax law change was $334.0 million. As of December 31, 2017, we have not completed our accounting for the tax effects of the new law and the effect on our existing deferred tax balances. We have made a reasonable estimate of its impact on our deferred tax balances. The following table summarizes our tax activity for each of the last three years ended (in thousands):

	2017	2016	2015
Total income (loss) before income taxes	$ 82,120	$ (802,138)	$ (1,052,362)
U.S. federal statutory rate	35%	35%	35%
Total tax expense (benefit) at statutory rate	28,742	(280,748)	(368,327)
Federal rate change	(333,961)	—	—
State and local income taxes, net of federal benefit	(604)	(23,514)	(45,179)
State rate and law change	(1,092)	(8,116)	2,006
Non-deductible executive comp	585	1,575	1,265
Non-deductible transaction costs	—	5,051	—
Tax less than book equity compensation	24,843	5,285	—
Change in valuation allowances:			
Federal valuation allowances & other	3,088	2,552	38,747
State valuation allowances & other	27,120	16,874	32,716
Permanent differences and other	253	291	95
Total benefit for income taxes	$ (251,026)	$ (280,750)	$ (338,677)
Effective tax rate	(305.7%)	35.0%	32.2%

We estimate our ability to utilize our deferred tax assets by analyzing the reversal patterns of our temporary differences, our loss carryforward periods and the Pennsylvania net operating loss carryforward limitations. Uncertainties such as future commodity prices can affect our calculations and the expiration of loss carryforwards prior to utilization can result in recording a partial as opposed to a full valuation allowance. We expect our effective tax rate to be approximately 24% for 2018, before any discrete tax items. Such estimated rate is based on our current assumptions with respect to, among other things, our earnings, state income tax levels and deductions. We adopted a March 2016 accounting standards update that simplified several aspects of accounting for share-based payment awards in fourth quarter 2016. The net impact of adopting the March 2016 standard was an increase to retained earnings of $103.2 million, a decrease to deferred tax liability for $101.1 million and an increase in tax expense of $2.1 million.

Management's Discussion and Analysis of Financial Condition, Cash Flows, Capital Resources and Liquidity

Cash Flows

The following table presents sources and uses of cash and cash equivalents for each of the last three years (in thousands):

	2017	2016	2015
Sources of cash and cash equivalents			
Operating activities	$ 816,254	$ 387,068	$ 691,402
Disposal of assets	72,468	193,755	890,901
Borrowing on credit facility	2,041,000	2,274,000	2,271,000
Issuance of debt	—	—	750,000
MRD Merger, net of cash acquired	—	7,180	—
Other	110,841	71,530	37,541
Total sources of cash and cash equivalents	$ 3,040,563	$ 2,933,533	$ 4,640,844
Uses of cash and cash equivalents			
Additions to natural gas and oil properties	$ (1,148,613)	$ (466,252)	$ (1,030,644)
Acreage purchases	(58,213)	(43,482)	(74,880)
Other property	(5,710)	(3,052)	(4,441)
Debt repayments	(500)	(273,012)	(516,875)
Repayments on credit facility	(1,712,000)	(1,487,000)	(2,899,000)
Repayment of Memorial credit facility	—	(597,000)	—
Dividends paid	(19,840)	(16,682)	(27,083)
Other	(95,553)	(47,210)	(87,898)
Total uses of cash and cash equivalents	$ (3,040,429)	$ (2,933,690)	$ (4,640,821)

Cash flows from operating activities are primarily affected by production volumes and commodity prices, net of the effects of settlements of our derivatives. Our cash flows from operating activities also are impacted by changes in working capital. We generally maintain low cash and cash equivalent balances because we use available funds to reduce our bank debt. Short-term liquidity needs are satisfied by borrowings under our bank credit facility. Because of this, and because our principal source of operating cash flows (proved reserves to be produced in the following year) cannot be reported as working capital, we often have low or negative working capital. We sell a portion of our production at the wellhead under floating market contracts. From time to time, we enter into various derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future natural gas, NGLs and oil production. The production we hedge has and will continue to vary from year to year depending on, among other things, our expectation of future commodity prices. Since year-end 2017, we have entered into additional natural gas and NGLs hedges for 2018 and 2019. Any payments due to counterparties under our derivative contracts should ultimately be funded by prices received from the sale of our production. Production receipts, however, often lag payments to the counterparties. Any interim cash needs are funded by borrowings under the bank credit facility. As of December 31, 2017, we have entered into derivative agreements covering 443.2 Bcfe for 2018 and 47.0 Bcfe for 2019, not including our basis swaps.

Net cash provided from operating activities in 2017 was $816.3 million compared to $387.1 million in 2016 and $691.4 million in 2015. The increase in cash provided from operating activities reflects significantly higher production volumes (an increase of 30%) and a 12% increase in realized prices. The decrease in cash provided from operating activities from 2015 to 2016 reflects significantly lower realized prices (a decline of 28%), expenses related to the MRD Merger and costs related to the senior subordinated note exchange partially offset by an 11% increase in production and lower operating costs. Net cash provided from operating activities is also affected by working capital changes or the timing of cash receipts and disbursements. Changes in working capital (as reflected in our consolidated statements of cash flows) for 2017 was a negative $47.2 million compared to a negative $106.4 million for 2016 and negative $9.1 million in 2015.

Disposal of assets in 2017 includes net proceeds of $30.8 million from the sale of properties in Western Oklahoma and $40.4 million of proceeds from the sale of properties in the Texas Panhandle. In 2016 net proceeds of $78.6 million were received from the sale of various Western Oklahoma properties and $111.5 million of proceeds received from the sale of our non-operated interest in certain wells and gathering facilities in Northeast Pennsylvania. In 2015, $876.0 million of proceeds were received, before closing adjustments, from the sale of our Virginia and West Virginia properties, which closed on December 30, 2015. For additional details related to our dispositions, see Note 3 to our consolidated financial statements.

Issuance of debt in 2015 includes the issuance of $750.0 million aggregate principal amount of 4.875% senior notes due 2025. For additional information, see Note 8 to our consolidated financial statements.

Additions to natural gas and oil properties are our most significant use of cash and cash equivalents. These cash outlays are associated with our drilling and completion capital budget program. In September 2016, we completed the MRD Merger which added natural gas and oil properties in North Louisiana. The following table shows capital expenditures by region and reconciles to additions to natural gas and oil properties as presented on our consolidated statement of cash flows for each of the last three years (in thousands):

	2017	2016	2015
Appalachian	$ 736,799	$ 469,082	$ 786,457
North Louisiana	465,820	62,348	—
Other	4,225	7,639	22,653
Total	1,206,844	539,069	809,110
Change in capital expenditure accrual for proved properties	(58,231)	(72,817)	221,534
Additions to natural gas and oil properties	$ 1,148,613	$ 466,252	$ 1,030,644

Debt repayments in 2016 includes amounts paid to purchase some of the Memorial senior notes assumed in the MRD Merger. The year ended December 31, 2015 includes the redemption of $500.0 million of our outstanding 6.75% senior subordinated notes due 2020. See Note 8 to our consolidated financial statement for additional information on debt repayments.

Liquidity and Capital Resources

Our main sources of liquidity and capital resources are internally generated cash flow from operating activities, a bank credit facility with uncommitted and committed availability, asset sales and access to the debt and equity capital markets. We must find new and develop existing reserves to maintain and grow our production and cash flows. We accomplish this primarily through successful drilling programs which require substantial capital expenditures. Lower prices for natural gas, NGLs and oil may reduce the amount of natural gas, NGLs and oil we can economically produce and can also affect the amount of cash flow available for capital expenditures and our ability to borrow or raise additional capital.

We currently believe that net cash generated from operating activities, unused committed borrowing capacity under our bank credit facility and proceeds from asset sales combined with our natural gas, NGLs and oil derivatives currently in place will be adequate to satisfy near-term financial obligations and liquidity needs. To the extent our capital requirements exceed our internally generated cash flow and proceeds from asset sales, borrowings under our bank credit facility or debt or equity may be issued to fund these requirements. Long-term cash flows are subject to a number of variables including the level of production and prices as well as various economic conditions that have historically affected the natural gas and oil business. Over the past several years, natural gas and crude oil prices have remained depressed, but have improved recently. We establish a capital budget at the beginning of each calendar year and review it during the course of the year. Our 2018 capital budget is $941.2 million. Actual capital expenditure levels may vary significantly due to many factors, including drilling results, natural gas, NGLs, crude oil and condensate prices, industry conditions, the prices and availability of goods and services, the extent to which properties are acquired or non-strategic assets sold. We have adjusted and must continue to adjust our business through efficiencies and cost reductions to compete in the current price environment which also requires reductions in overall debt levels over time. We may, from time to time, depending on market conditions, our liquidity requirements, contractual restrictions and other factors, seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for other debt or equity securities in open market purchases, privately negotiated transactions or otherwise. The amounts involved may be material. We plan to continue working towards profitable growth within cash flows. At December 31, 2017, we had approximately $507.6 million of liquidity.

We believe that we will have adequate capital resources and liquidity for the foreseeable future because (1) we have significant borrowing capacity under our bank credit facility with a maturity of 2019 (2) we have commodity derivatives in place which cover a portion of our 2018 and 2019 production (3) we can reduce our capital expenditures for extended periods of time if necessary and (4) the maturity of our senior and senior subordinated notes extend four years or more and such notes carry attractive fixed interest rates ranging from 4.875% to 5.875%.

Credit Arrangements

Long-term debt at December 31, 2017 totaled $4.1 billion, including $1.2 billion of bank credit facility debt, $2.9 billion of senior notes and $49.0 million of senior subordinated notes. As of December 31, 2017, we maintain a bank credit facility with a borrowing base of $3.0 billion and aggregate lender commitments of $2.0 billion. As of December 31, 2017, we also have $281.4 million of undrawn letters of credit. The bank credit facility is secured by substantially all of our assets and has a maturity date of October 16, 2019. Availability under the bank credit facility, during a non-investment grade period, is subject to a borrowing base set by the lenders annually (at their discretion) with an option to reset the borrowing base more often in certain circumstances. Availability under the bank credit facility during an investment grade period is limited to the aggregate lender commitments. The borrowing base is dependent on a number of factors, but primarily the lenders' assessments of future cash flows. Redeterminations of the borrowing base to maintain or reduce the amount thereof require approval of two thirds of the lenders; increases require 95% approval.

Our bank credit facility imposes limitations on the payment of dividends and other restricted payments (as defined under the debt agreements for our bank debt). The debt agreements also contain customary covenants relating to debt incurrence, liens, investments and financial ratios. We were in compliance with all covenants at December 31, 2017.

Proved Reserves

To maintain and grow production and cash flow, we must continue to develop existing proved reserves and locate or acquire new natural gas, NGLs and oil reserves. The following is a discussion of proved reserves, reserve additions and revisions and future net cash flows from proved reserves.

	Year End December 31,		
	2017	2016	2015
		(Mmcfe)	
Proved Reserves:			
Beginning of year	12,072,322	9,891,663	10,310,229
Reserve additions	3,487,519	1,394,134	1,265,348
Reserve revisions	506,919	255,794	(211,163)
Purchases	10,116	1,259,806	—
Sales	(81,133)	(164,655)	(963,423)
Production	(733,382)	(564,420)	(509,328)
End of year	15,262,361	12,072,322	9,891,663
Proved Developed Reserves:			
Beginning of year	6,769,908	5,422,075	5,349,761
End of year	8,348,074	6,769,908	5,422,075

Our proved reserves at year-end 2017 were 15.3 Tcfe compared to 12.1 Tcfe at year-end 2016 and 9.9 Tcfe at year-end 2015. Natural gas comprised approximately 67%, 65% and 63% of our proved reserves at year-end 2017, 2016 and 2015.

Reserve Additions and Revisions. During 2017, we added approximately 3.5 Tcfe of proved reserves from drilling activities and evaluation of proved areas primarily in the Marcellus Shale. Approximately 82% of 2017 reserve additions was attributable to natural gas. Included in 2017 proved reserves is a total of 360.6 Mmbbls of ethane reserves (1,596 Bcfe) in the Marcellus Shale, which represents reserves that match volumes delivered under our existing long-term, extendable contracts. Revisions of previous estimates of 506.9 Bcfe include positive pricing revisions of 46.3 Bcfe, improved recovery for our Marcellus Shale natural gas properties of 597.0 Bcfe and positive performance revisions of 531.9 Bcfe somewhat offset by 668.3 Bcfe of reserves reclassified to unproved due to drilling plans.

During 2016, we added approximately 1.4 Tcfe of proved reserves from drilling activities and evaluation of proved areas primarily in the Marcellus Shale. Approximately 86% of 2016 reserve additions was attributable to natural gas. Included in 2016 proved reserves is a total of 308.9 Mmbbls of ethane reserves (1,367 Bcfe) in the Marcellus Shale, which represents reserves that match volumes delivered under our existing long-term, extendable contracts. Revisions of previous estimates of 255.8 Bcfe include negative pricing revisions of 23.1 Bcfe and 268.7 Bcfe of reserves reclassified to unproved due to drilling plans more than offset by improved recovery for our Marcellus Shale natural gas properties of 393.2 Bcfe and positive performance revisions of 154.4 Bcfe.

During 2015, we added approximately 1.3 Tcfe of proved reserves from drilling activities and evaluation of proved areas primarily in the Marcellus Shale. Approximately 80% of 2015 reserve additions was attributable to natural gas. Included in 2015 proved reserves is a total of 292.8 Mmbbls of ethane reserves (1,296 Bcfe) in the Marcellus Shale, which represents reserves that match volumes delivered under our existing long term, extendable contracts. Revisions of previous estimates of a net reduction of 211 Bcfe include negative pricing revisions and 1.2 Tcfe of reserves reclassified to unproved because of reduced future capital spending due to lower commodity prices partially offset by improved recovery for our Marcellus Shale natural gas properties of 781.0 Bcfe and positive performance revisions.

Purchases. In 2017, we purchased 10.1 Bcfe of reserves in North Louisiana. In 2016, we purchased 1.3 Tcfe of reserves related to the MRD Merger.

Sales. In 2017, we sold 74.6 Bcfe of reserves in Western Oklahoma and the Texas Panhandle and 6.6 Bcfe of reserves in Pennsylvania. In 2016, we sold 137.5 Bcfe of reserves related to non-operated properties in Northeast Pennsylvania and 24.3 Bcfe of reserves in Western Oklahoma. In 2015, we sold 963.4 Bcfe of reserves primarily related to our Virginia and West Virginia natural gas and oil properties.

Future Net Cash Flows. At December 31, 2017, the present value (discounted at 10%) of estimated future net cash flows from our proved reserves was $8.1 billion. The present value of our estimated future net cash flows at December 31, 2016 was $3.7 billion.

This present value was calculated based on the unweighted average first-day-of-the-month oil and gas prices for the prior twelve months held flat for the life of the reserves, in accordance with SEC rules. At December 31, 2017, the after-tax present value of estimated future net cash flows from our proved reserves was $7.2 billion compared to $3.4 billion at December 31, 2016.

The present value of future net cash flows does not purport to be an estimate of the fair market value of our proved reserves. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves and a discount factor more representative of the time value of money to the evaluating party and the perceived risks inherent in producing oil and gas.

Capitalization and Dividend Payments

As of December 31, 2017 and 2016, our total debt and capitalization were as follows (in thousands):

	2017	2016
Bank debt	$ 1,208,467	$ 876,428
Senior notes	2,851,754	2,848,591
Senior subordinated notes	48,585	48,498
Total debt	4,108,806	3,773,517
Stockholders' equity	5,774,272	5,408,368
Total capitalization	$ 9,883,078	$ 9,181,885
Debt to capitalization ratio	41.6%	41.1%

The amount of future dividends is subject to declaration by the board of directors and primarily depends on earnings, capital expenditures and various other factors. In 2017, we paid $19.8 million in dividends to our common stockholders ($0.02 per share per quarter). In 2016, we paid $16.7 million in dividends to our common stockholders ($0.02 per share per quarter). In 2015, we paid $27.1 million in dividends to our common stockholders ($0.04 per share per quarter).

Cash Contractual Obligations

Our contractual obligations include long-term debt, operating leases, derivative obligations, asset retirement obligations, and transportation, gathering and processing commitments. As of December 31, 2017, we do not have any capital leases or any significant off-balance sheet debt or other such unrecorded obligations and we have not guaranteed any debt of any unrelated party. As of December 31, 2017, we had a total of $281.4 million of letters of credit outstanding under our bank credit facility. The table below provides estimates of the timing of future payments that we are obligated to make based on agreements in place at December 31, 2017. In addition to the contractual obligations listed on the table below, our consolidated balance sheet at December 31, 2017 reflects accrued interest payable on our bank debt of $4.4 million which is payable in first quarter 2018. We expect to make interest payments of $28.6 million per year on our 5.75% senior and senior subordinated notes, $67.4 million per year on our 5.0% senior and senior subordinated notes, $36.6 million per year on our 4.875% senior notes and $19.4 million on our 5.875% senior notes.

The following summarizes our contractual financial obligations at December 31, 2017 and their future maturities. We expect to fund these contractual obligations with cash generated from operating activities, borrowings under our bank credit facility, additional debt issuances and proceeds from asset sales (in thousands).

	Payment due by period					
	2018	2019	2020	2021 and 2022	Thereafter	Total
Debt:						
Bank debt due 2019 [a]	$ —	$ 1,211,000	$ —	$ —	$ —	$ 1,211,000
5.75% senior subordinated notes due 2021	—	—	—	22,214	—	22,214
5.0% senior subordinated notes due 2022	—	—	—	19,054	—	19,054
5.0% senior subordinated notes due 2023	—	—	—	—	7,712	7,712
5.75% senior notes due 2021	—	—	—	475,952	—	475,952
5.00% senior notes due 2022	—	—	—	580,032	—	580,032
5.00% senior notes due 2023	—	—	—	—	741,531	741,531
5.875% senior notes due 2022	—	—	—	329,834	—	329,834
4.875% senior notes due 2025	—	—	—	—	750,000	750,000
Other obligations:						
Operating leases	15,026	14,331	13,771	19,514	32,909	95,551
Transportation and gathering commitments	805,161	825,231	767,090	1,425,101	4,689,133	8,511,716
Asset retirement obligation liability [b]	6,327	39	—	117	270,372	276,855
Total contractual obligations [c]	$ 826,514	$ 2,050,601	$ 780,861	$ 2,871,818	$ 6,491,657	$ 13,021,451

[a] Due at termination date of our bank credit facility. Interest paid on our bank credit facility would be approximately $20.9 million each year assuming no change in the interest rate or outstanding balance.

[b] The ultimate settlement amount and timing cannot be precisely determined in advance. See Note 9 to our consolidated financial statements.

[c] This table excludes the liability for the deferred compensation plans since these obligations will be funded with existing plan assets.

In addition to the amounts included in the above table, we have entered into an additional transportation agreement which is contingent on certain pipeline modifications and/or construction. This agreement has a twenty year term beginning on the satisfaction of these contingencies, which may take place in 2018. Based on this contract, we will have additional transportation obligations for natural gas volumes of 400,000 mcf per day until 2038.

Delivery Commitments

We have various volume delivery commitments that are related to our Marcellus Shale, Oklahoma and North Louisiana areas. We expect to be able to fulfill our contractual obligations from our own production; however, we may purchase third party volumes to satisfy our commitments or pay demand fees for commitment shortfalls, should they occur. As of December 31, 2017, our delivery commitments through 2031 were as follows:

Year Ending December 31,	Natural Gas (mmbtu per day)	Ethane and Propane (bbls per day)
2018	382,534	71,000
2019	364,356	55,932
2020	252,878	48,625
2021	116,189	48,000
2022	68,712	43,000
2023	—	35,000
2024 — 2028	—	35,000
2029 — 2031	—	20,000

In addition to the amounts included in the above table, we have contracted with several pipeline companies through 2020 to deliver ethane production volumes from our Marcellus Shale wells. These agreements and related fees, which are contingent upon pipeline construction and/or modification, are for 13,000 bbls per day starting in 2018. In addition, we have agreements in place to deliver natural gas volumes from our Marcellus Shale wells, which are also contingent upon pipeline construction and/or modification for 15,000 mcf per day starting in late 2018, increasing to 65,000 mcf per day in early 2019 and 180,000 mcf per day in late 2019.

Other

In conjunction with the MRD Merger, we have various midstream service agreements in North Louisiana for gathering, processing and transportation of natural gas and NGLs. Pursuant to the gas processing agreement, we must pay a quarterly deficiency payment based on the firm-commitment fixed fee if the cumulative minimum volume commitment as of the end of a quarter exceeds the sum of (i) the cumulative volumes processed under the processing agreement as of the end of the quarter plus (ii) volumes corresponding to deficiency payments incurred prior to each quarter.

We lease acreage that is generally subject to lease expiration if initial wells are not drilled within a specified period, generally between three and five years. 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, including the cost of infrastructure to connect production, we have allowed acreage to expire and will allow additional acreage to expire in the future. To date, our expenditures to comply with environmental or safety regulations have not been a significant component of our cost structure and are not expected to be significant in the future. However, new regulations, enforcement policies, claims for damages, or other events could result in significant future costs.

Hedging – Natural Gas, Oil and NGLs Prices

We use commodity-based derivative contracts to help manage exposures to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. We do not utilize complex derivatives as we typically utilize commodity swaps, swaptions and collars to (1) reduce the effect of price volatility on the commodities we produce and sell and (2) support our annual capital budget and expenditure plans. In addition, we may utilize basis contracts to hedge the differential between NYMEX and those of our physical pricing points or between Mont Belvieu and international propane indexes. For more discussion of our derivative activities, see Management's Discussion of Critical Accounting Estimates – *Natural Gas and Oil Derivatives* below and Item 7A. Quantitative and Qualitative Disclosures about Market Risk – *Commodity Price Risk* and *Other Commodity Risk*. For more information regarding the accounting for our derivatives, see the discussion in Notes 2, 11 and 12 to our consolidated financial statements. While there is a risk that the financial benefit of rising natural gas, NGLs and oil prices may not be captured, we believe the benefits of stable and predictable cash flow are more important. Among these benefits are a more efficient utilization of existing personnel and planning for future staff additions, the flexibility to enter into long-term projects requiring substantial committed capital, smoother and more efficient execution of our ongoing development drilling and production enhancement programs, more consistent returns on invested capital, and better access to bank and other credit markets.

Interest Rates

At December 31, 2017, we had $4.1 billion of debt outstanding. Of this amount, $2.9 billion bears interest at fixed rates averaging 5.2%. Bank debt totaling $1.2 billion bears interest at floating rates, which averaged 3.0% at year-end 2017. The 30-day LIBOR rate on December 31, 2017 was 1.6%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2017 would cost us approximately $12.1 million in additional annual interest expense.

Off-Balance Sheet Arrangements

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

Inflation and Changes in Prices

Our revenues, the value of our assets and our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in natural gas, NGLs and oil prices and the costs to produce our reserves. Natural gas, NGLs and oil prices are subject to significant fluctuations that are beyond our ability to control or predict. Although certain of our costs and expenses are affected by general inflation, inflation does not normally have a significant effect on our business. We expect costs in 2018 to continue to be a function of supply and demand. Natural gas and oil prices have remained depressed but have recently improved. We continue to experience a decline in our cost structure.

Management's Discussion of Critical Accounting Estimates

Our discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at year-end, the reported amounts of revenues and expenses during the year and proved natural gas and oil reserves. Some accounting policies involve judgments and uncertainties to such an extent there is a reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying value of assets and liabilities that are not readily apparent from other sources. Actual results could differ from the estimates and assumptions used.

Certain accounting estimates are considered to be critical if (1) the nature of the estimates and assumptions is material due to the level of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to changes; and (2) the impact of the estimates and assumptions on financial condition or operating performance is material. Actual results could differ from the estimates and assumptions used.

Natural Gas and Oil Properties

We use the successful efforts method of accounting for natural gas and oil producing activities as opposed to the alternate acceptable full cost method. We believe that net assets and net income are more conservatively measured under the successful efforts method of accounting than under the full cost method, particularly during periods of active exploration. One difference between the successful efforts method of accounting and the full cost method is under the successful efforts method all exploratory dry holes and geological and geophysical costs are charged against earnings during the periods they occur; whereas, under the full cost method of accounting, such costs are capitalized as assets, pooled with the costs of successful wells and charged against earnings of future periods as a component of depletion expense. Under the successful efforts method of accounting, successful exploration drilling costs and all development costs are capitalized and these costs are systematically charged to expense using the units of production method based on proved developed natural gas and oil reserves as estimated by our engineers and audited by independent engineers. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized on our balance sheet if (1) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (2) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. Proven property leasehold costs are amortized to expense using the units of production method based on total proved reserves. Properties are assessed for impairment as circumstances warrant (at least annually) and impairments to value are charged to expense. The successful efforts method inherently relies upon the estimation of proved reserves, which includes proved developed and proved undeveloped volumes.

Proved reserves are defined by the SEC as those volumes of natural gas, NGLs, condensate and crude oil that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods. Although our engineers are knowledgeable of and follow the guidelines for reserves established by the SEC, the estimation of reserves requires engineers to make a significant number of assumptions based on professional judgment. Reserve estimates are updated at least annually and consider recent production levels and other technical information. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information, including reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price and cost changes and other economic factors. Changes in natural gas, NGLs and oil prices can lead to a decision to start up or shut in production, which can lead to revisions to reserve quantities. Reserve revisions in turn cause adjustments in our depletion rates. We cannot predict what reserve revisions may be required in future periods. 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. For additional discussion, see in Items 1 & 2. Business and Properties – *Proved Reserves* of this report. To further ensure the reliability of our reserve estimates, we engage independent petroleum consultants to audit our estimates of proved reserves. Estimates prepared by third parties may be higher or lower than those included herein. Independent petroleum consultants audited approximately 98% of our reserves in 2017 compared to 96% in 2016 and 94% in 2015. Historical variances between our reserve estimates and the aggregate estimates of our consultants have been less than 5%. The reserves included in this report are those reserves estimated by our petroleum engineering staff.

Depletion rates are determined based on reserve quantity estimates and the capitalized costs of producing properties. As the estimated reserves are adjusted, the depletion expense for a property will change, assuming no change in production volumes or the capitalized costs. While total depletion expense for the life of a property is limited to the property's total cost, proved reserve revisions result in a change in the timing of when depletion expense is recognized. Downward revisions of proved reserves may result in an acceleration of depletion expense, while upward revisions tend to lower the rate of depletion expense recognition. Based on proved reserves at December 31, 2017, we estimate that a 1% change in proved reserves would increase or decrease 2018 depletion expense by approximately $6.0 million (based on current production estimates). Estimated reserves are used as the basis for calculating the expected future cash flows from property asset groups, which are used to determine whether that property may be impaired. Reserves are also used to estimate the supplemental disclosure of the standardized measure of discounted future net cash flows relating to natural gas and oil producing activities and reserve quantities in Note 18 to our consolidated financial statements. Changes in the estimated reserves are considered a change in estimate for accounting purposes and are reflected on a prospective basis. It should not be assumed that the standardized measure is the current market value of our estimated proved reserves.

We monitor our long-lived assets recorded in natural gas and oil properties in our consolidated balance sheets to ensure they are fairly presented. We must evaluate our properties for potential impairment when circumstances indicate that the carrying value of an asset could exceed its fair value. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future natural gas, NGLs and oil prices, an estimate of the ultimate amount of recoverable natural gas, NGLs and oil reserves that will be produced from the property asset groups future production, future production costs, future abandonment costs, and future inflation. Many assumptions are inherent, and to some extent, interdependent of one another in our estimate of future cash flows. The use of alternate judgments and assumptions could result in different levels of impairment charges. The need to test a property asset group for impairment can be based on several factors, including a significant reduction in sales prices for natural gas, NGLs and/or oil, unfavorable adjustments to reserves, physical damage to production equipment and facilities, a change in costs, or other changes to contracts or environmental regulations. Our natural gas and oil properties are reviewed for potential impairments at the lowest levels for which there are identifiable cash flows that are largely independent of other groups of assets which is the level at which depletion is calculated. The review is done by determining if the historical cost of proved properties less the applicable accumulated depreciation, depletion and amortization is less than the estimated undiscounted future net cash flows. We estimate prices based upon market-related information including published futures prices. The estimated future level of production, which is based on proved and risk adjusted probable and possible reserves, has assumptions surrounding the future levels of prices and costs, field decline rates, market demand and supply and the economic and regulatory climates. In certain circumstances, we also consider potential sales of properties to third parties in our estimates of future cash flows. When the carrying value exceeds the sum of future net cash flows, an impairment loss is recognized for the difference between the estimated fair market value (as determined by discounted future net cash flows using a discount rate similar to that used by market participants) and the carrying value of the asset. We cannot predict whether impairment charges may be required in the future. Our recorded impairment of producing natural gas and oil properties was $63.7 million in 2017 compared to $43.0 million in 2016 and $590.2 million in 2015. In 2017, $63.7 million of impairment was recorded related to natural gas and oil properties in Oklahoma and the Texas Panhandle due to the possibility of sale of these properties. In 2016, an impairment of $43.0 million was recorded related to natural gas properties in Oklahoma due to lower prices and the possibility of a sale of these properties. In 2015, an impairment of $306.6 million was recorded related to natural gas and oil properties in Northern Oklahoma, $195.6 million of impairment expense related to our shallow legacy oil and natural gas assets in Northwest Pennsylvania, $86.9 million related to our assets in the Texas Panhandle and $1.1 million related to onshore Gulf Coast properties. Our 2015 impairment expense was due to significantly lower natural gas and oil prices. We believe that a sensitivity analysis regarding the effect of changes in assumptions on estimated impairment is impractical to provide because of the number of assumptions and variables involved which have interdependent effects on the potential outcome. If natural gas, NGLs and oil prices decrease or drilling efforts are unsuccessful, we may be required to record additional impairments.

We evaluate our unproved property investment periodically for impairment. The majority of these costs generally relate to the acquisition of leaseholds. The costs are capitalized and evaluated (at least quarterly) as to recoverability, based on changes brought about by economic factors and potential shifts in business strategy employed by management. Impairment of a significant portion of our unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. Potential impairment of individually significant unproved property is assessed on a property-by-property basis considering a combination of time, geologic and engineering factors. In certain circumstances, our future plans to develop acreage many accelerate our impairment. We have recorded abandonment and impairment expense related to unproved properties of $269.7 million in 2017 compared to $30.1 million in 2016 and $47.6 million in 2015.

Goodwill

As a result of our MRD acquisition in September 2016, we have goodwill in the amount of $1.6 billion at December 31, 2017, the excess of consideration transferred over the fair value of MRD. Goodwill is not amortized but tested for impairment annually, as of November 1st, or more frequently if events or circumstances indicate that impairment may exist. We apply a fair value based impairment test to the carrying value of our business (our reporting unit) in certain events or circumstances. We assess the value of our business under either a qualitative or quantitative approach. Under a qualitative approach, we consider various market factors, including applicable key assumptions listed below. These factors are analyzed to determine if events and circumstances have affected the fair value of our business. If we determine that it is more likely than not that our business is impaired, the quantitative approach is used to assess asset's fair value and the amount of the impairment. Under a quantitative approach, the fair value is calculated based on key assumptions listed below. If our carrying value exceeds our fair value calculated using the quantitative approach, an impairment charge is recorded for the difference in fair value and carrying value.

When performing a quantitative impairment assessment, fair value is estimated based on a combination of (i) recent market transactions, where available; and (ii) projected discounted cash flows (an income approach). Under the income approach, the fair value is based on the present value of expected future cash flows. The income approach is dependent on a number of factors including estimates of forecasted revenue and operating costs, proved reserves, as well as the success of future exploration for and development of unproved reserves, discount rates and other variables. Negative revisions of estimated reserves quantities, increases in future cost estimates, divestitures or sustained decreases in crude oil or natural gas prices could lead to a reduction in expected future cash flows and possibly an impairment of all or a portion of goodwill in future periods. Key assumptions used in the discounted cash flow model described above include estimated quantities of crude oil, natural gas and NGL reserves, including both proved reserves and risk-adjusted unproved reserves; estimates of market prices considering forward commodity price curves as of the measurement date; and estimates of operating, administrative and capital costs adjusted for inflation. We discount the resulting future cash flows using a peer company based weighted average cost of capital. Under the market approach, we would estimate the fair value by comparison to similar businesses whose securities are actively traded in the public market. This requires management to make certain judgments including the selection of comparable companies and/or comparable recent company asset transactions, transaction premiums and selected financial metrics.

We performed a quantitative impairment test during third quarter 2017 due to a significant decline in our market capitalization. Management utilized the assistance of a third-party valuation expert to determine the fair value of our business. The fair value was determined based on a combination of a market and an income approach. As a result of this measurement, the fair value of our business exceeded the carrying value of net assets and no impairment was recorded. As of the date of our third quarter 2017 impairment assessment, our fair value exceeded book value by $1.4 billion or 24%. After considering the impact of the tax cuts and Job Act of 2017 which was signed into law on December 31, 2017, our fair value would have exceeded book value by $2.4 billion or 42%.

During fourth quarter 2017, we conducted a qualitative goodwill impairment assessment by examining relevant events and circumstances which could have a negative impact on our business such as: macroeconomic conditions, industry and market conditions, including the downturn in the oil and gas industry, cost factors that could have a negative effect on earnings and cash flows, overall financial performance, dispositions and acquisitions, and other relevant entity-specific events. We identified factors, including commodity prices, our year end proved reserves evaluation and the market value of our common stock. Our analysis indicated that our fair value was not below our book value. Although we based the fair value estimate of our business on assumptions we believe to be reasonable, those assumptions are inherently unpredictable and uncertain. In addition, a qualitative reconciliation of our market capitalization to the fair value used in our impairment assessment is performed to test the reasonableness of our fair value. We believe that a sensitivity analysis regarding the effects of changes in assumptions on estimated goodwill impairment is impractical to provide because of the number of assumptions and variables involved which have interdependent effects on the potential outcome. If natural gas, NGLs and oil prices decrease, drilling efforts are unsuccessful or our market capitalization declines further, it is reasonably possible that we would be required to record additional impairments.

Fair Value Estimates

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

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

- Level 1-Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the measurement date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2-Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the measurement date.
- Level 3-Unobservable inputs for which there is little, if any, market activity for the asset or liability being measured. These inputs reflect management's best estimates of the assumptions market participants would use in determining fair value. Our Level 3 measurements consist of instruments using standard pricing models and other valuation methods that utilize unobservable pricing inputs that are significant to the overall value.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. See Note 12 to the consolidated financial statements for disclosures regarding our fair value measurements. Significant uses of fair value measurements include:

- impairment assessments of long-lived assets;
- allocation of the purchase price paid to acquire businesses as to the assets acquired and liabilities assumed;

- impairment assessments of goodwill; and
- recorded value of derivative instruments.

The need to test long-lived assets and goodwill can be based on several indicators, including a significant reduction in prices of natural gas, oil and condensate, NGLs, sustained declines in our common stock, unfavorable adjustments to reserves, significant changes in the expected timing of production, other changes to contracts or changes in the regulatory environment in which a property is located.

Natural Gas, NGLs and Oil Derivatives

All derivative instruments are recorded on our consolidated balance sheets as either an asset or a liability measured at its fair value. Fair value measurements for all of our derivatives are based on observable market-based inputs that are corroborated by market data and are discussed in Note 11 to our consolidated financial statements. Additional information about derivatives and their valuation may be found in Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

Asset Retirement Obligations

We have significant obligations to remove tangible equipment and restore the surface at the end of natural gas and oil production operations. Removal and restoration obligations are primarily associated with plugging and abandoning wells. Estimating the future asset removal costs is difficult and requires us to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate retirement costs, inflation factors, credit-adjusted discount rates, timing of retirement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation ("ARO"), a corresponding adjustment is made to the natural gas and oil property balance. For example, as we analyze actual plugging and abandonment information, we may revise our estimate of current costs, the assumed annual inflation of the costs and/or the assumed productive lives of our wells. During 2017, we increased our existing ARO by $12.5 million or approximately 5% of the ARO balance at December 31, 2016. This was primarily due to an increase in our estimated costs to plug and abandon certain wells in North Louisiana and Pennsylvania. During 2016, we decreased our existing ARO by $26.8 million or approximately 10% of the ARO balance at December 31, 2015. This was primarily due a decrease in our estimated costs to plug and abandon certain wells in Pennsylvania. See Note 9 to the consolidated financial statements for disclosures regarding our asset retirement obligation estimates. In addition, increases in the discounted ARO resulting from the passage of time are reflected as accretion expense, a component of depletion, depreciation and amortization in the accompanying consolidated statements of operations. Because of the subjectivity of assumptions and the relatively long lives of most of our wells, the costs to ultimately retire our wells may vary significantly from prior estimates. An estimate of the sensitivity to net income of other assumptions that had been used in recording these liabilities is not practical because of the number of obligations that must be assessed, the number of underlying assumptions and the wide range of possible assumptions.

Income Taxes

We are subject to income and other taxes in all areas in which we operate. When recording income tax expense and benefit, certain estimates are required because income tax returns are generally filed many months after the close of a calendar year, tax returns are subject to audit, which can take years to complete, and future events often impact the timing of when income tax expenses and benefits are recognized. We have recorded deferred tax assets and liabilities for temporary differences between book basis and tax basis, tax credit carryforwards and operating loss carryforwards. We have deferred tax assets relating to tax operating loss carryforwards and other deductible differences. We routinely assess the realizability of our deferred tax assets and reduce such assets by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. In assessing the need for additional or adjustments to existing valuation allowances, we consider the preponderance of evidence concerning the realization of the deferred tax asset. We consider any prudent and feasible tax planning strategies that might minimize the amount of any valuation allowance recognized against deferred tax assets. At December 31, 2017, we had a tax basis of $2.2 billion related to prior years' capitalized intangible drilling costs, which will be amortized over the next five years.

Our net deferred tax assets, after valuation allowances, are expected to be realized through the reversal of temporary differences. During 2017, we increased our valuation allowance against our state net operating loss carryforwards, basis differences and credits from $58.4 million as of December 31, 2016 to $93.8 million as of December 31, 2017. The federal valuation allowances decreased from $48.7 million as of December 31, 2016 to $31.3 million as of December 31, 2017. See Note 5 to our consolidated financial statements for further information concerning our income taxes.

We may be challenged by taxing authorities over the amount and/or timing of recognition of revenues and deductions in our various income tax returns. Although we believe that we have adequately provided for all taxes, income or losses could occur in the future due to changes in estimates or resolution of outstanding tax matters.

The Tax Cuts and Job Act of 2017 was signed into law on December 22, 2017. The new law significantly reforms the Internal Revenue Code of 1986, as amended. As of December 31, 2017, we have not completed our accounting for the tax effects of the new law and the impact on our existing deferred tax balances. We have made a reasonable estimate of the impact on our deferred tax balances.

Contingent Liabilities

A provision for legal, environmental and other contingent matters is charged to expense when the loss is probable and the cost or range of cost can be reasonably estimated. Judgment is often required to determine when expenses should be recorded for legal, environmental and contingent matters. In addition, we often must estimate the amount of such losses. In many cases, our judgment is based on the input of our legal advisors and on the interpretation of laws and regulations, which can be interpreted differently by regulators and/or the courts. Actual costs can differ from estimates for many reasons. We monitor known and potential legal, environmental and other contingent matters and make our best estimate of when to record losses for these matters based on available information. Although we continue to monitor all contingencies closely, particularly our outstanding litigation, we currently have no material accruals for contingent liabilities.

Revenue Recognition

Natural gas, NGLs and oil sales are recognized when we deliver our production to the customer and collectability is reasonably assured. We use the sales method to account for gas imbalances, recognizing revenue based on gas delivered rather than our working interest share of gas produced. We generally sell natural gas, NGLs and oil under two types of agreements, which are common in our industry. Both types of agreements include transportation charges. One type of agreement is a netback arrangement, under which we sell natural gas and oil at the wellhead and collect a price, net of transportation incurred by the purchaser. In this case, we record revenue at the net price we received from the purchaser. In the case of NGLs, we may also receive a net price from the purchaser (which is net of processing costs) which is recorded as revenue at the net price. Under the other arrangement, we sell natural gas, NGLs or oil at a specific delivery point, pay transportation, gathering, processing and compression to a third party and receive proceeds from the purchaser with no deduction. In that case, we record revenue at the price received from the purchaser and record these third party costs as transportation, gathering and compression expense.

Stock-based Compensation Arrangements

The fair value of performance-based share awards (where the performance condition is based on market conditions) is estimated on the date of grant using a Monte Carlo simulation method. A Monte Carlo simulation model utilizes multiple input variables that determine the probability of satisfying the market condition stipulated in the award grant. The fair value of restricted stock awards and performance-based awards where the performance condition is based on internal performance metrics is determined based on the fair market value of our common stock on the date of grant.

We recognize stock-based compensation expense on a straight-line basis over the requisite service period for the entire award. The expense we recognize is net of estimated forfeitures. We estimate our forfeiture rate based on prior experience and adjust it as circumstances warrant. See Note 13 to our consolidated financial statements for more information.

Accounting Standards Not Yet Adopted

Refer to Note 2 to our consolidated financial statements for a discussion of new accounting pronouncements that may affect us in the future.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in natural gas, NGLs and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market-risk exposure. All of our market-risk sensitive instruments were entered into for purposes other than trading. All accounts are U.S. dollar denominated.

Market Risk

We are exposed to market risks related to the volatility of natural gas, NGLs and oil prices. We employ various strategies, including the use of commodity derivative instruments, to manage the risks related to these price fluctuations. These derivative instruments apply to a varying portion of our production and provide only partial price protection. These arrangements limit the benefit to us of increases in prices but offer protection in the event of price declines. Further, if our counterparties defaulted, this protection might be limited as we might not receive the benefits of the derivatives. Realized prices are primarily driven by worldwide prices for oil and spot market prices for North American natural gas production. Natural gas and oil prices have been volatile and unpredictable for many years. Natural gas prices affect us more than oil prices because approximately 67% of our December 31, 2017 proved reserves were natural gas. We are also exposed to market risks related to changes in interest rates. These risks did not change materially from December 31, 2016 to December 31, 2017.

Commodity Price Risk

We use commodity-based derivative contracts to manage exposures to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. At times, certain of our derivatives are swaps where we receive a fixed price for our production and pay market prices to the counterparty. Our derivatives program may also include collars, which establish a minimum floor price and a predetermined ceiling price. In third quarter 2017, we entered into combined natural gas derivative instruments containing a fixed price swap and a sold option to extend or double the volume (which we refer as a swaption). The swap price is a fixed price determined at the time of the swaption contract. If the option is exercised, the contract will become a swap treated consistently with our fixed-price swaps. At December 31, 2017, our derivatives program includes swaps, swaptions and collars. These contracts expire monthly through December 2019. Their fair value, represented by the estimated amount that would be realized upon immediate liquidation as of December 31, 2017, approximated a net derivative asset of $13.6 million compared to a net derivative liability of $187.2 million at December 31, 2016. This change is primarily related to the settlements of derivative contracts during 2017 and to the natural gas, NGLs and oil futures prices as of December 31, 2017 in relation to the new commodity derivative contracts we entered into during 2017 for 2018 and 2019. At December 31, 2017, the following commodity derivative contracts were outstanding, excluding our basis swaps which are discussed below:

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price	Fair Market Value (in thousands)
Natural Gas				
2018	Swaps	794,822 Mmbtu/day	$ 3.13	$ 87,731
2019	Swaps	12,329 Mmbtu/day	$ 3.01	$ (154)
January − March 2018	Collar	60,000 Mmbtu/day	$ 3.40-$ 3.76	$ 3,039
April – December 2018	Swaptions	307,500 Mmbtu/day	$ 2.98 [1]	$ 10,357
2019	Swaptions	85,000 Mmbtu/day	$ 2.97 [1]	$ (3,823)
Crude Oil				
2018	Swaps	8,995 bbls/day	$ 53.30	$ (19,524)
2019	Swaps	4,746 bbls/day	$ 52.81	$ (5,200)
NGLs (C2-Ethane)				
2018	Swaps	250 bbls/day	$ 0.29/gallon	$ 57
NGLs (C3-Propane)				
2018	Swaps	10,362 bbls/day	$ 0.68/gallon	$ (34,324)
2018	Collar	2,000 bbls/day	$ 0.90-$1.05/gallon	$ 85
NGLs (NC4-Normal Butane)				
2018	Swaps	4,621 bbls/day	$ 0.81/gallon	$ (11,188)
NGLs (C5-Natural Gasoline)				
2018	Swaps	4,713 bbls/day	$ 1.19/gallon	$ (13,043)
2019	Swaps	1,000 bbls/day	$ 1.24/gallon	$ (445)

(1) Contains a combined derivative instrument consisting of a fixed price swap and a sold option to extend or double the volume. For April through December 2018, we have swaps in place for 147,500 Mmbtu per day on which the counterparty can elect to double the volume at a weighted average price of $2.89. We also have swaps in place for 160,000 Mmbtu per day on which the counterparty can elect to extend the contract through December 2019 at a weighted average price of $3.07. In 2019, if the counterparty elects to double the volume, we would have additional swaps covering 85,000 Mmbtu per day at a weighted average price of $2.97.

In the future, we expect our NGLs production to continue to increase. In our Marcellus Shale operations, propane is a large product component of our NGLs production and we believe NGLs prices are somewhat seasonal. Therefore, the percentage of NGLs prices to NYMEX WTI (or West Texas Intermediate) will vary due to product components, seasonality and geographic supply and demand. We sell NGLs in several regional and international markets. If we are not able to sell or store NGLs, we may be required to curtail production or shift our drilling activities to dry gas areas.

Currently, the Appalachian region has limited local demand and infrastructure to accommodate ethane. We have previously announced agreements wherein we have contracted to either sell or transport ethane from our Marcellus Shale area, two of which began operations in late 2013. Our Mariner East transportation agreement and our terminal/storage arrangement at Sunoco's Marcus

Hook Industrial Complex facility near Philadelphia began operations in early 2016. If we are not able to sell a portion of our ethane, we may be required to curtail production which will adversely affect our revenues and cash flow. However, as we have done in the past, we also may be able to purchase or divert natural gas to blend with our rich residue gas.

Other Commodity Risk

We are impacted by basis risk as natural gas transaction prices are frequently based on industry reference prices that may vary from prices experienced in local markets. If commodity price changes in one region are not reflected in other regions, derivative commodity instruments may no longer provide the expected hedge, resulting in increased basis risk. In addition to the swaps above, we have entered into natural gas basis swap agreements. The price we receive for our natural gas production can be more or less than the NYMEX price because of adjustments for delivery location ("basis"), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively lock in the basis adjustments. The fair value of the natural gas basis swaps was a net derivative liability of $7.8 million at December 31, 2017; the volumes are for 120,892,500 Mmbtu and they expire monthly through October 2019.

As of December 31, 2017, we also had propane spread swap contracts which lock in the differential between Mont Belvieu and international propane indices. These contracts settle monthly through December 2019 and include total volume of 1,362,000 barrels in 2018. The fair value of these contracts was a net derivative liability of $1.2 million on December 31, 2017.

In connection with our international propane swaps, at December 31, 2017, we had freight swap contracts which lock in the freight rate for a specific trade route on the Baltic Exchange. These contracts settle monthly through December 2018 and cover 5,000 metric tons per month with a fair value net derivative asset of $276,000 on December 31, 2017.

Commodity Sensitivity Analysis

The following table shows the fair value of our swaps and basis swaps and the hypothetical change in fair value that would result from a 10% and a 25% change in commodity prices at December 31, 2017. We remain at risk for possible changes in the market value of commodity derivative instruments; however, such risks should be mitigated by price changes in the underlying physical commodity (in thousands):

		Hypothetical Change in Fair Value		Hypothetical Change in Fair Value	
		Increase in Commodity Price of		Decrease in Commodity Price of	
	Fair Value	10%	25%	10%	25%
Swaps	$ 3,910	$ (141,951)	$ (353,804)	$ 142,904	$ 357,733
Swaptions	6,534	(49,058)	(138,372)	39,967	91,045
Collars	3,124	(2,012)	(4,722)	2,067	5,209
Basis swaps	(8,986)	524	1,230	(482)	(1,199)
Freight swaps	276	197	493	(197)	(493)

Our commodity-based contracts expose us to the credit risk of non-performance by the counterparty to the contracts. Our exposure is diversified among major investment grade financial institutions and commodity traders and we have master netting agreements with the majority of our counterparties that provide for offsetting payables against receivables from separate derivative contracts. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. At December 31, 2017, our derivative counterparties include nineteen financial institutions, of which all but five are secured lenders in our bank credit facility. Counterparty credit risk is considered when determining the fair value of our derivative contracts. While counterparties are major investment grade financial institutions and large commodity traders, the fair value of our derivative contracts have been adjusted to account for the risk of non-performance by certain of our counterparties, which was immaterial. Our propane sales from the Marcus Hook facility near Philadelphia are short-term and are to a single purchaser. Ethane sales from Marcus Hook are to a single international customer bearing a credit rating similar to Range.

Interest Rate Risk

We are exposed to interest rate risk on our bank debt. We attempt to balance variable rate debt, fixed rate debt and debt maturities to manage interest costs, interest rate volatility and financing risk. This is accomplished through a mix of fixed rate publically traded debt and variable rate bank debt. At December 31, 2017, we had $4.1 billion of debt outstanding. Of this amount, $2.9 billion bears interest at a fixed rate averaging 5.2%. Bank debt totaling $1.2 billion bears interest at floating rates, which was 3.0% at December 31, 2017. On December 31, 2017, the 30-day LIBOR rate was 1.6%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2017 would cost us approximately $12.1 million in additional annual interest expense.

The fair value of our senior and subordinated debt is based on year-end December 2017 quoted market prices. The following table presents information on these fair values (in thousands):

	Carrying Value	Fair Value
Fixed rate debt:		
Senior Subordinated Notes due 2021 (The interest rate is fixed at a rate of 5.75%)	$ 22,214	$ 22,192
Senior Subordinated Notes due 2022 (The interest rate is fixed at a rate of 5.00%)	19,054	18,741
Senior Subordinated Notes due 2023 (The interest rate is fixed at a rate of 5.00%)	7,712	7,614
Senior Notes due 2021 (The interest rate is fixed at a rate of 5.75%)	475,952	493,872
Senior Notes due 2022 (The interest rate is fixed at a rate of 5.00%)	580,032	578,727
Senior Notes due 2022 (The interest rate is fixed at a rate of 5.875%)	329,834	339,792
Senior Notes due 2023 (The interest rate is fixed at a rate of 5.00%)	741,531	735,614
Senior Notes due 2025 (The interest rate is fixed at a rate of 4.875%)	750,000	733,755
	$ 2,926,329	$ 2,930,307

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

RANGE RESOURCES CORPORATION

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

To the Stockholders of Range Resources Corporation:

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Our internal control over financial reporting is designed to provide reasonable assurance regarding the preparation and fair presentation of published financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even when determined to be effective, can only provide reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2017. In making this assessment, which was conducted under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control – Integrated Framework (2013).* Based on our assessment, we believe that, as of December 31, 2017, our internal control over financial reporting is effective based on those criteria.

Ernst and Young LLP, the independent registered public accounting firm that audited our financial statements included in this annual report, has issued an attestation report on our internal control over financial reporting as of December 31, 2017. This report appears on the following page.

By: /s/ JEFFREY L. VENTURA
Jeffrey L. Ventura
Chairman, President and Chief Executive Officer

By: /s/ ROGER S. MANNY
Roger S. Manny
Executive Vice President and Chief Financial Officer

Fort Worth, Texas
February 27, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of Range Resources Corporation

Opinion on Internal Control over Financial Reporting

We have audited Range Resources Corporation's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Range Resources Corporation (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of Range Resources Corporation as of December 31, 2017 and 2016, and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes and our report dated February 27, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Ernst & Young LLP

Fort Worth, Texas
February 27, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of Range Resources Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Range Resources Corporation (the Company) as of December 31, 2017 and 2016, the related consolidated statements of operations, comprehensive income (loss), stockholders' equity and cash flows for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2017 and 2016, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 27, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2003.

Fort Worth, Texas
February 27, 2018

RANGE RESOURCES CORPORATION
CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

	December 31, 2017	December 31, 2016
Assets		
Current assets:		
Cash and cash equivalents	$ 448	$ 314
Accounts receivable, less allowance for doubtful accounts of $7,111 and $5,559	348,833	241,718
Derivative assets	58,607	13,278
Inventory and other	21,346	26,573
Total current assets	429,234	281,883
Derivative assets	273	205
Goodwill	1,641,197	1,654,292
Natural gas and oil properties, successful efforts method	13,216,453	12,386,153
Accumulated depletion and depreciation	(3,649,716)	(3,129,816)
	9,566,737	9,256,337
Other property and equipment	114,361	112,796
Accumulated depreciation and amortization	(99,695)	(95,923)
	14,666	16,873
Other assets	76,734	72,655
Total assets	$ 11,728,841	$ 11,282,245
Liabilities		
Current liabilities:		
Accounts payable	$ 343,871	$ 229,190
Asset retirement obligations	6,327	7,271
Accrued liabilities	317,531	265,843
Accrued interest	43,511	35,340
Derivative liabilities	44,233	165,009
Total current liabilities	755,473	702,653
Bank debt	1,208,467	876,428
Senior notes	2,851,754	2,848,591
Senior subordinated notes	48,585	48,498
Deferred tax liabilities	693,356	943,343
Derivative liabilities	9,789	24,491
Deferred compensation liabilities	101,102	119,231
Asset retirement obligations and other liabilities	286,043	310,642
Total liabilities	5,954,569	5,873,877
Commitments and contingencies		
Stockholders' Equity		
Preferred stock, $1 par 10,000,000 shares authorized, none issued and outstanding	—	—
Common stock, $0.01 par 475,000,000 shares authorized, 248,144,397 issued at December 31, 2017 and 247,174,903 issued at December 31, 2016	2,481	2,471
Common stock held in treasury, 14,967 shares at December 31, 2017 and 30,547 shares at December 31, 2016	(599)	(1,209)
Additional paid-in capital	5,577,732	5,524,423
Accumulated other comprehensive loss	(1,332)	—
Retained earnings (deficit)	195,990	(117,317)
Total stockholders' equity	5,774,272	5,408,368
Total liabilities and stockholders' equity	$ 11,728,841	$ 11,282,245

See accompanying notes.

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share data)

	Year Ended December 31,		
	2017	2016	2015
Revenues and other income:			
Natural gas, NGLs and oil sales	$ 2,176,287	$ 1,197,215	$ 1,089,644
Derivative fair value income (loss)	213,350	(261,391)	416,364
Brokered natural gas, marketing and other	221,393	164,115	92,060
Total revenues and other income	2,611,030	1,099,939	1,598,068
Costs and expenses:			
Direct operating	134,252	97,388	136,363
Transportation, gathering, processing and compression	761,183	565,209	396,739
Production and ad valorem taxes	42,882	25,443	33,860
Brokered natural gas and marketing	220,311	168,576	115,866
Exploration	53,662	32,325	21,406
Abandonment and impairment of unproved properties	269,725	30,076	47,619
General and administrative	233,406	184,772	194,015
MRD Merger expenses	—	37,225	—
Termination costs	3,770	(519)	15,070
Deferred compensation plan	(50,915)	19,153	(77,627)
Interest	195,679	168,213	166,439
Loss on early extinguishment of debt	—	—	22,495
Depletion, depreciation and amortization	624,992	524,102	581,155
Impairment of proved properties	63,679	43,040	590,174
(Gain) loss on the sale of assets	(23,716)	7,074	406,856
Total costs and expenses	2,528,910	1,902,077	2,650,430
Income (loss) before income taxes	82,120	(802,138)	(1,052,362)
Income tax (benefit) expense:			
Current	17	98	29
Deferred	(251,043)	(280,848)	(338,706)
	(251,026)	(280,750)	(338,677)
Net income (loss)	$ 333,146	$ (521,388)	$ (713,685)
Net income (loss) per common share:			
Basic	$ 1.34	$ (2.75)	$ (4.29)
Diluted	$ 1.34	$ (2.75)	$ (4.29)
Weighted average common shares outstanding:			
Basic	245,091	189,868	166,389
Diluted	245,458	189,868	166,389

See accompanying notes.

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(In thousands)

	Year Ended December 31,		
	2017	**2016**	**2015**
Net income (loss)	$ 333,146	$ (521,388)	$ (713,685)
Other comprehensive loss:			
Postretirement benefits:			
Prior service cost	(1,769)	—	—
Income tax benefit	437	—	—
Total comprehensive income (loss)	$ 331,814	$ (521,388)	$ (713,685)

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See accompanying notes.

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2017	**2016**	**2015**
Operating activities:			
Net income (loss)	$ 333,146	$ (521,388)	$ (713,685)
Adjustments to reconcile net income (loss) to net cash provided from operating activities:			
Deferred income tax benefit	(251,043)	(280,848)	(338,706)
Depletion, depreciation and amortization and impairment	688,671	567,142	1,171,329
Exploration dry hole and impairment costs	9,172	18	88
Abandonment and impairment of unproved properties	269,725	30,076	47,619
Derivative fair value (income) loss	(213,350)	261,391	(416,364)
Cash settlements on derivative financial instruments	13,117	347,336	532,122
Allowance for bad debt	1,550	800	2,300
Amortization of deferred financing costs, loss on extinguishment of debt and other	5,445	7,170	29,383
Deferred and stock-based compensation	30,706	74,685	(20,411)
(Gain) loss on the sale of assets	(23,716)	7,074	406,856
Changes in working capital:			
Accounts receivable	(102,866)	(20,586)	64,704
Inventory and other	(2,979)	6,220	(14,868)
Accounts payable	45,912	(27,259)	(26,197)
Accrued liabilities and other	12,764	(64,763)	(32,768)
Net cash provided from operating activities	816,254	387,068	691,402
Investing activities:			
Additions to natural gas and oil properties	(1,148,613)	(466,252)	(1,030,644)
Additions to field service assets	(5,710)	(3,052)	(4,441)
Acreage purchases	(58,213)	(43,482)	(74,880)
MRD Merger, net of cash acquired	—	7,180	—
Other	—	—	(75)
Proceeds from disposal of assets	72,468	193,755	890,901
Purchases of marketable securities held by the deferred compensation plan	(88,167)	(37,019)	(28,876)
Proceeds from the sales of marketable securities held by the deferred compensation plan	89,178	40,035	29,243
Net cash used in investing activities	(1,139,057)	(308,835)	(218,772)
Financing activities:			
Borrowings on credit facilities	2,041,000	2,274,000	2,271,000
Repayments on credit facilities	(1,712,000)	(1,487,000)	(2,899,000)
Repayment of Memorial credit facility	—	(597,000)	—
Issuance of senior notes	—	—	750,000
Repayment of senior or senior subordinated notes	(500)	(273,012)	(516,875)
Dividends paid	(19,839)	(16,682)	(27,083)
Debt issuance costs	(403)	(6,342)	(14,156)
Taxes paid for shares withheld	(6,983)	(3,849)	(7,702)
Change in cash overdrafts	17,180	18,393	(37,089)
Proceeds from the sales of common stock held by the deferred compensation plan	4,482	13,102	8,298
Net cash provided from (used in) financing activities	322,937	(78,390)	(472,607)
Increase (decrease) in cash and cash equivalents	134	(157)	23
Cash and cash equivalents at beginning of year	314	471	448
Cash and cash equivalents at end of year	$ 448	$ 314	$ 471

See accompanying notes.

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In thousands, except per share data)

	Common stock		Common stock held in treasury	Additional paid-in capital	Retained earnings/(deficit)	Accumulated other comprehensive loss	Total
	Shares	Par value					
Balance as of December 31, 2014	168,711	$ 1,687	$ (3,088)	$ 2,400,475	$ 1,058,355	$ —	**$ 3,457,429**
Issuance of common stock	665	6	—	10,067	—	—	**10,073**
Stock-based compensation expense	—	—	—	36,496	—	—	**36,496**
Tax benefit related to stock-based compensation	—	—	—	(3,572)	—	—	**(3,572)**
Common dividends declared ($0.16 per share)	—	—	—	—	(27,083)	—	**(27,083)**
Treasury stock issuance	—	—	843	(843)	—	—	—
Net loss	—	—	—	—	(713,685)	—	**(713,685)**
Balance as of December 31, 2015	169,376	1,693	(2,245)	2,442,623	317,587	—	**2,759,658**
Issuance of common stock	77,799	778	—	3,047,875	—	—	**3,048,653**
Stock-based compensation expense	—	—	—	37,023	—	—	**37,023**
Tax benefit related to stock-based compensation	—	—	—	(2,062)	—	—	**(2,062)**
Common dividends declared ($0.08 per share)	—	—	—	—	(16,682)	—	**(16,682)**
Cumulative-effect adjustment from adoption of ASU 2016-09	—	—	—	—	103,166	—	**103,166**
Treasury stock issuance	—	—	1,036	(1,036)	—	—	—
Net loss	—	—	—	—	(521,388)	—	**(521,388)**
Balance as of December 31, 2016	247,175	2,471	(1,209)	5,524,423	(117,317)	—	**5,408,368**
Issuance of common stock	969	10	—	2,977	—	—	2,987
Stock-based compensation expense	—	—	—	50,942	—	—	50,942
Common dividends declared ($0.08 per share)	—	—	—	—	(19,839)	—	(19,839)
Treasury stock issuance	—	—	610	(610)	—	—	—
Other comprehensive loss	—	—	—	—	—	(1,332)	(1,332)
Net income	—	—	—	—	333,146	—	333,146
Balance as of December 31, 2017	**248,144**	**$ 2,481**	**$ (599)**	**$ 5,577,732**	**$ 195,990**	**$ (1,332)**	**$ 5,774,272**

See accompanying notes.

(1) Summary of Organization and Nature of Business

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

(2) Summary of Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

The accompanying consolidated financial statements include the accounts of all of our subsidiaries. All material intercompany balances and transactions have been eliminated.

Use of Estimates

The preparation of financial statements in accordance with U.S. GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from these estimates and changes in these estimates are recorded when known.

Business Segment Information

We have evaluated how we are organized and managed and have identified only one operating segment, which is the exploration and production of natural gas, NGLs and oil in the United States. We consider our gathering, processing and marketing functions as integral to our natural gas and oil producing activities. Operating segments are defined as components of an enterprise that engage in activities from which it may earn revenues and incur expenses for which separate operational financial information is available and this information is regularly evaluated by the chief operating decision maker for the purpose of allocating resources and assessing performance.

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 a geographical or area-by-area basis. Throughout the year, we allocate capital resources on a project-by-project basis, across our entire asset base to optimize returns without regard to individual areas.

Revenue Recognition, Accounts Receivable and Gas Imbalances

Natural gas, NGLs and oil sales are recognized when we deliver our production to the customer and collectability is reasonably assured. We generally sell natural gas, NGLs and oil under two types of agreements, which are common in our industry. Both types of agreements include transportation charges. We are reporting our gathering and transportation costs in accordance with Accounting Standards Code Section 605-45-05 of Subtopic 605-45 for Revenue Recognition. One type of agreement is a netback arrangement, under which we sell natural gas and oil at the wellhead and collect a price, net of transportation incurred by the purchaser. In this case, we record revenue at the price we receive from the purchaser. For the sale of our NGLs, in some cases, we receive a price from the purchaser (which is net of processing costs) that is recorded in revenue at the net price we receive. Under the other type of agreement, we sell natural gas, NGLs or oil at a specific delivery point, pay transportation, gathering, processing and compression expenses to a third party and receive proceeds from the purchaser with no deduction. In that case, we record revenue at the price received from the purchaser and record the expenses we incur as transportation, gathering, processing and compression expense.

We realize brokered margins as a result of buying and selling natural gas utilizing separate purchase and sale transactions, typically with separate counterparties, whereby Range or the counterparty takes title to the natural gas purchased or sold. Revenues and expenses related to brokered natural gas are reported gross as part of revenues and expenses in accordance with applicable accounting standards. Our net brokered margin was a loss of $5.7 million in 2017 compared to losses of $2.8 million in 2016 and losses of $2.7 million in 2015.

Although receivables are concentrated in the oil and gas industry, we do not view this as an unusual credit risk. We provide for an allowance for doubtful accounts for specific receivables judged unlikely to be collected based on the age of the receivable, our experience with the debtor, potential offsets to the amount owed and economic conditions. In certain instances, we require purchasers to post stand-by letters of credit. Many of our receivables are from joint interest owners of properties we operate. Thus, we may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. We have allowances for doubtful accounts relating to exploration and production receivables of $7.1 million at December 31, 2017 compared to $5.6 million at December 31, 2016. We recorded bad debt expense of $1.6 million in the year ended December 31, 2017 compared to $800,000 in the year ended December 31, 2016 and $2.3 million in the year ended 2015.

Revenues from the production of natural gas, NGLs and oil on properties in which we have joint ownership are recorded under the sales method. Under the sales method, we and other joint owners may sell more or less than our entitled share of production. Should our sales exceed our share of remaining reasonable reserves, a liability is recorded. Imbalances are not significant in the periods presented.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and on deposit and investments in highly liquid debt instruments with maturities of three months or less. Outstanding checks in excess of funds on deposit are included in accounts payable on the consolidated balance sheets and the change in such overdrafts is classified as a financing activity on the consolidated statements of cash flows.

Marketable Securities

Investments in unaffiliated equity securities held in our deferred compensation plans qualify as trading securities and are recorded at fair value. Investments held in the deferred compensation plans consist of various publicly-traded mutual funds. These funds include equity securities and money market instruments and are reported in other assets in the accompanying consolidated balance sheets.

Inventory

Inventories were comprised of $12.1 million of materials and supplies at December 31, 2017 compared to $9.4 million at December 31, 2016. Inventories consist primarily of tubular goods and equipment used in our operations and are stated at the lower of specific cost of each inventory item or net realizable value, on a first-in, first-out basis. Our material and supplies inventory is primarily acquired for use in future drilling operations or repair operations and is reviewed periodically for obsolescence or impairment when market conditions indicate. At December 31, 2017, we also had commodity inventory of $508,000, compared to $8.3 million at December 31, 2016, which is carried at lower of weighted average cost or net realizable value, on a first-in, first-out basis. Commodity inventory at December 31, 2017 consists of NGLs held as line fill in pipelines or tanks.

Goodwill

As a result of our merger with Memorial Resource Development Corp. (the "MRD Merger" or "Memorial") in September 2016, we have goodwill in the amount of $1.6 billion at December 31, 2017, the excess of consideration transferred over the fair value of Memorial. Goodwill is not amortized but tested for impairment annually, as of November 1st, or more frequently if events or circumstances indicate that impairment may exist. We apply a fair value based impairment test to the carrying value of our business (our reporting unit). We assess the value of our business under either a qualitative or quantitative approach. Under a qualitative approach, we consider various market factors, including applicable key assumptions we have listed below. These factors are analyzed to determine if events and circumstances have affected the fair value of our business. If we determine that it is more likely than not that our business is impaired, the quantitative approach is used to assess our fair value and the amount of the impairment. Under a quantitative approach, the fair value is calculated based on key assumptions we have listed below. If our carrying value exceeds our fair value calculated using the quantitative approach, an impairment charge is recorded for the difference between fair value and carrying value. For more information, see Note 4.

Performing a qualitative impairment assessment of our business requires an examination of relevant events and circumstances that could have a negative impact on our business, such as macroeconomic conditions, industry and market conditions (including current commodity price), earnings and cash flows, overall financial performance and other relevant entity specific events.

When performing a quantitative impairment assessment of goodwill, fair value is estimated based on a combination of (i) recent market transactions, where available; and (ii) projected discounted cash flows (an income approach). Under the income approach, the fair value is based on the present value of expected future cash flows. The income approach is dependent on a number of factors including estimates of forecasted revenue and operating costs, proved reserves, as well as the success of future exploration for and development of unproved reserves, discount rates and other variables. Negative revisions of estimated reserves quantities, increases in future cost estimates, divestitures or sustained decreases in crude oil or natural gas prices could lead to a reduction in expected future cash flows and possibly an impairment of all or a portion of goodwill in future periods. Key assumptions used in the discounted cash flow model include estimated quantities of crude oil, natural gas and NGLs reserves, including both proved reserves and risk-adjusted unproved reserves; estimates of market prices considering forward commodity price curves as of the measurement date; and estimates of operating, administrative and capital costs adjusted for inflation. We discount the resulting future cash flows using a peer company based weighted average cost of capital. Under the market approach, we would estimate fair value by a comparison to similar businesses whose securities are actively traded in the public market. This requires management to make certain judgments including the selection of comparable companies and/or comparable recent company asset transactions, transaction premiums and selected financial metrics. If natural gas, NGLs and oil prices decrease, drilling efforts are unsuccessful or our market capitalization declines further, it is reasonably possible that we would be required to record additional impairments.

Natural Gas and Oil Properties

Property Acquisition Costs. We use the successful efforts method of accounting for natural gas and oil producing activities. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs, delay rentals and costs of carrying and retaining unproved properties are expensed. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. The status of suspended well costs is monitored continuously and reviewed not less than quarterly. We capitalize successful exploratory wells and all developmental wells, whether successful or not. Due to the capital-intensive nature and the geographical location of certain projects, it may take an extended period of time to evaluate the future potential of an exploration project and the economics associated with making a determination on its commercial viability. In these instances, the project's feasibility is not contingent upon price improvements or advances in technology, but rather our ongoing efforts and expenditures related to accurately predicting the hydrocarbon recoverability based on well information, gaining access to other companies' production data in the area, transportation or processing facilities and/or obtaining partner approval to drill additional appraisal wells. These activities are ongoing and are being pursued constantly. Consequently, our assessment of suspended exploratory well costs is continuous until a decision can be made that the project has found proved reserves to sanction the project or is noncommercial and is charged to exploration expense. For more information regarding suspended exploratory well costs, see Note 7.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of proved producing properties, including other property and equipment such as gathering lines related to natural gas and oil producing activities, is provided on the units of production method. Historically, we have adjusted our depletion rates in the fourth quarter of each year based on the year-end reserve report and at other times during the year when circumstances indicate there has been a significant change in reserves or costs. In the year ended December 31, 2015, the fair value of our natural gas and oil properties in Northwest Pennsylvania was determined to be zero. As a result, any future adjustments to the asset retirement liability for these properties represents an impairment expense and we have elected to record such expense in depreciation, depletion and amortization. In the year ended December 31, 2017, additional expense of $158,000 was recorded related to these costs compared to $1.9 million in the year ended December 31, 2016.

Impairments. Our proved natural gas and oil properties are reviewed for impairment annually and periodically as events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. These assets are reviewed for potential impairment at the lowest level for which there are identifiable cash flows that are largely independent of other groups of assets which is the level at which depletion is calculated. The review is done by determining if the historical cost of proved properties less the applicable accumulated depreciation, depletion and amortization is less than the estimated expected undiscounted future net cash flows. The expected future net cash flows are estimated based on our plans to produce and develop reserves. Expected future net cash inflow from the sale of produced reserves is calculated based on estimated future prices and estimated operating and development costs. We estimate prices based upon market-related information including published futures prices. The estimated future level of production, which is based on proved and risk adjusted probable and possible reserves, has assumptions surrounding the future levels of prices and costs, field decline rates, market demand and supply, and the economic and regulatory climate. In certain circumstances, we also consider potential sales of properties to third parties in our estimates of cash flows. When the carrying value exceeds the sum of undiscounted future net cash flows, an impairment loss is recognized for the difference between the estimated fair market value (as determined by discounted future net cash flows using a discount rate similar to that used by market participants) and the carrying value of the asset. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future natural gas and oil prices, an estimate of the ultimate amount of recoverable natural gas and oil reserves that will be produced from an asset group, the timing of future production, future production costs, future abandonment costs and future inflation. We cannot predict whether impairment charges may be required in the future. If natural gas, NGLs and oil prices decrease or drilling efforts are unsuccessful, we may be required to record additional impairments. For additional information regarding proved property impairments, see Note 12.

We evaluate our unproved property investment periodically for impairment. The majority of these costs generally relate to the acquisition of leasehold costs. The costs are capitalized and evaluated (at least quarterly) as to recoverability, based on changes brought about by economic factors and potential shifts in business strategy employed by management. Impairment of a significant portion of our unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. Impairment of individually significant unproved property is assessed on a property-by-property basis considering a combination of time, geologic and engineering factors. In certain circumstances, our future plans to develop acreage may accelerate our impairment. Unproved properties had a net book value of $2.6 billion as of December 31, 2017 compared to $2.9 billion in 2016. We have recorded abandonment and impairment expense related to unproved properties of $269.7 million in the year ended December 31, 2017 compared to $30.1 million in 2016 and $47.6 million in 2015.

Dispositions. Proceeds from the disposal of natural gas and oil producing properties that are part of an amortization base are credited to the net book value of the amortization group with no immediate effect on income. However, gain or loss is recognized if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the amortization base. Dispositions are accounted for as a sale of assets. For additional information regarding our dispositions, see Note 3.

Acquisitions. Acquisitions of proved properties are accounted for as either a business combination or an asset acquisition and, accordingly, the results of operations are included in the accompanying consolidated statements of operations from the closing date of the acquisition. In a business combination, purchase prices are allocated to acquired assets and assumed liabilities based on their estimated fair value at the time of the acquisition. In an asset acquisition, fair value is assigned to the assets acquired. In the past, acquisitions have been funded with internal cash flow, bank borrowings and the issuance of debt and equity securities. For additional information regarding our acquisitions, see Note 3.

Other Property and Equipment

Other property and equipment includes assets such as buildings, furniture and fixtures, field equipment, leasehold improvements and data processing and communication equipment. These items are generally depreciated by individual components on a straight-line basis over their economic useful life, which is generally from three to ten years. Leasehold improvements are amortized over the lesser of their economic useful lives or the underlying terms of the associated leases. Depreciation expense was $7.7 million in the year ended December 31, 2017 compared to $8.4 million in the year ended December 31, 2016 and $11.9 million in the year ended December 31, 2015.

Other Assets

Other assets at December 31, 2017 include $67.1 million of marketable securities held in our deferred compensation plans and $9.6 million of other investments including surface acreage. Other assets at December 31, 2016 include $61.7 million of marketable securities held in our deferred compensation plans and $10.6 million of other investments including surface acreage.

Stock-based Compensation Arrangements

We account for stock-based compensation under the fair value method of accounting. We grant various types of stock-based awards including restricted stock and performance-based awards. The fair value of our restricted stock awards and our performance-based awards (where the performance condition is based on internal performance metrics) is based on the market value of our common stock on the date of grant. The fair value of our performance-based awards where the performance condition is based on market conditions is estimated using a Monte Carlo simulation method.

We recognize stock-based compensation expense on a straight-line basis over the requisite service period for the entire award. The expense we recognize is net of estimated forfeitures. We estimate our forfeiture rate based on prior experience and adjust it as circumstances warrant. If actual forfeitures are different than expected, adjustments to recognize expense may be required in future periods. To the extent possible, we limit the amount of shares to be issued for these awards by satisfying tax withholding requirements with cash. All awards have been issued at prevailing market prices at the time of grant and the vesting of these awards is based on an employee's continued employment with us, with the exception of employment termination due to death, disability or retirement. For additional information regarding stock-based compensation, see Note 13.

Derivative Financial Instruments and Hedging

All of our derivative instruments are issued to manage the price risk attributable to our expected natural gas, NGLs and oil production. While there is risk that the financial benefit of rising natural gas, NGLs and oil prices may not be captured, we believe the benefits of stable and predictable cash flow are more important. Among these benefits are more efficient utilization of existing personnel and planning for future staff additions, the flexibility to enter into long-term projects requiring substantial committed capital, smoother and more efficient execution of our ongoing development drilling and production enhancement programs, more consistent returns on invested capital and better access to bank and other capital markets. All unsettled derivative instruments are recorded in the accompanying consolidated balance sheets as either an asset or a liability measured at their fair value. In most cases, our derivatives are reflected on our consolidated balance sheets on a net basis by brokerage firm when they are governed by master netting agreements. Changes in a derivative's fair value are recognized in earnings. Cash flows from derivative contract settlements are reflected in operating activities in the accompanying consolidated statements of cash flows.

All realized and unrealized gains and losses on derivatives are accounted for using the mark-to-market accounting method. We recognize all unrealized and realized gains and losses related to these contracts in each period in derivative fair value in the accompanying consolidated statements of operations. Certain of our derivatives are swaps where we receive a fixed price for our production and pay market prices to the counterparty. We also have collars which establish a minimum floor price and a predetermined ceiling price. At times, we have also entered into basis swap agreements. The price we receive for our natural gas production can be more or less than the NYMEX price because of adjustments for delivery location ("basis"), relative quality and other factors; therefore, we have entered into natural gas basis swap agreements that effectively fix our basis adjustments. We have also entered into propane basis swaps which lock in the differential between Mont Belvieu and international propane indexes. In third quarter 2017, we entered into combined natural gas derivative instruments containing a fixed price swap and a sold option to extend or double the volume (which we refer to as a swaption). The swap price is a fixed price determined at the time of the swaption contract. If the option is exercised, the contract will become a swap treated consistently with our fixed-price swaps. For additional information regarding our derivatives, see Note 11.

From time to time, we may enter into derivative contracts and pay or receive premium payments at the inception of the derivative contract which represent the fair value of the contract at its inception. These amounts would be included within the net derivative asset or liability on our consolidated balance sheets. The amounts paid or received for derivative premiums reduce or increase the amount of gains and losses that are recorded in the earnings each period as the derivative contracts settle. During 2017, we did not modify any existing derivative contracts.

Concentrations of Credit Risk

As of December 31, 2017, our primary concentrations of credit risk are the risks of collecting accounts receivable and the risk of counterparties' failure to perform under derivative contracts. Most of our receivables are from a diverse group of companies, including major energy companies, pipeline companies, local distribution companies, financial institutions, commodity traders and end-users in various industries and such receivables are generally unsecured. To manage risks of collecting accounts receivable, we monitor our counterparties' financial strength and/or credit ratings and where we deem necessary, we obtain parent company guarantees, prepayments, letters of credit or other credit enhancements to reduce risk of loss. Our allowance for doubtful accounts was $7.1 million at December 31, 2017 compared to $5.6 million at December 31, 2016.

For the years ended December 31, 2017, 2016 and 2015, we had one customer that accounted for 10% or more of total natural gas, NGLs and oil sales. We believe that the loss of any one customer would not have an adverse effect on our ability to sell our natural gas, NGLs and oil production.

We have executed International Swap Dealers Association Master Agreements ("ISDA Agreements") with counterparties for the purpose of entering into derivative contracts. To manage counterparty risk associated with our derivatives, we select and monitor counterparties based on assessment of their financial strength and/or credit ratings. We may also limit the level of exposure with any single counterparty. Additionally, the terms of our ISDA Agreements provide us and our counterparties with netting rights such that we may offset payables against receivables with a counterparty under separate derivative contracts. Our ISDA Agreements also generally contain set-off rights such that, upon the occurrence of defined acts of default by either us or a counterparty to a derivative contract, the non-defaulting party may set-off receivables owed under all derivative contracts against payables from other agreements with that counterparty. The majority of our derivative contracts have no margin requirements or collateral provisions that would require us to fund or post additional collateral prior to the scheduled cash settlement date.

At December 31, 2017, our derivative counterparties included nineteen financial institutions and commodity traders, of which all but five are secured lenders in our bank credit facility. At December 31, 2017, our net derivative asset includes a payable to the counterparties not included in our bank credit facility totaling $28.2 million. In determining fair value of derivative assets, we evaluate the risk of non-performance and incorporate factors such as amounts owed under other agreements permitting set-off, as well as pricing of credit default swaps for the counterparty. Net derivative liabilities are determined in part by using our market based credit spread to incorporate our theoretical risk of non-performance.

Asset Retirement Obligations

The fair value of asset retirement obligations is recognized in the period they are incurred, if a reasonable estimate of fair value can be made. Asset retirement obligations primarily relate to the abandonment of natural gas and oil producing facilities and include costs to dismantle and relocate or dispose of production platforms, gathering systems, wells and related structures. Estimates are based on historical experience of plugging and abandoning wells, estimated remaining lives of those wells based on reserve estimates, external estimates of the cost to plug and abandon the wells in the future and federal and state regulatory requirements. We are required to operate and maintain our natural gas pipeline systems and intend to do so as long as supply and demand for natural gas exists, which we expect for the foreseeable future. Therefore, these assets have indeterminate lives. Depreciation of capitalized asset retirement costs will generally be determined on a units-of-production basis while accretion to be recognized will escalate over the life of the producing assets. See Note 9 for additional information.

Environmental Costs

Environmental expenditures are capitalized if the costs mitigate or prevent future contamination or if the costs improve environmental safety or efficiency of the existing assets. Expenditures that relate to an existing condition caused by past operations that have no future economic benefits are expensed.

Deferred Taxes

Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to the differences between the financial statement carrying amounts of assets and liabilities and their tax bases as reported in our filings with the respective taxing authorities. Deferred tax assets are recorded when it is more likely than not that they will be realized. The realization of deferred tax assets is assessed periodically based on several interrelated factors. These factors may include our expectation to generate sufficient taxable income in the periods before tax credits and operating loss carryforwards expire. All deferred taxes are classified as long-term on the balance sheet.

New Accounting Pronouncements

Recently Adopted

In January 2017, an accounting standards update was issued that eliminates the requirements to calculate the implied fair value of goodwill to measure any goodwill impairment charge. Instead, entities will record an impairment charge based on the excess of a reporting unit's carrying amount over its fair value. This standard is effective for annual periods beginning after December 15, 2019 and should be applied on a prospective basis. Early adoption is permitted for any goodwill impairment tests performed in first quarter 2017 or later. We elected to adopt this accounting standards update in first quarter 2017. The adoption did not have a significant impact on our consolidated results of operations, financial position, cash flows or financial disclosures; however, this standard did change our policy for our goodwill impairment assessment by eliminating the requirement to calculate the implied fair value of goodwill.

In March 2016, an accounting standards update was issued that simplifies several aspects of the accounting for share-based payment award transactions. Among other things, this new guidance will require all income tax effects of share-based awards to be recognized in the statement of operations when the awards vest or are settled, will allow an employer to repurchase more of an employee's shares for tax withholding purposes than it can today without triggering liability accounting and will allow a policy election to account for forfeitures as they occur. This new standard will be effective for annual periods beginning after December 15, 2016. Early adoption was permitted. We elected to early adopt this accounting standards update in fourth quarter 2016 which required us to reflect any adjustments as of January 1, 2016, the beginning of the annual period that included the interim period of adoption. The following summarizes the impact of this new standard on our consolidated financial statements:

Income taxes - Upon adoption of this standard, all excess tax benefits and tax deficiencies (including tax benefits of dividends on share-based payment awards) are recognized as income tax expense or benefit in our consolidated statements of operations. The tax effects of exercised or vested awards are treated as discrete items in the reporting period in which they occur. Adoption of this new standard resulted in the recognition of an excess tax deficiency in our provision for income taxes rather than paid-in capital of $2.1 million for the year ended December 31, 2016 and affected our previously reported first quarter 2016 results as follows (in thousands, except per share data):

	For The Three Months Ended March 31, 2016	
	As Reported	As Adjusted
Statements of Operations:		
Income tax benefit	$ (44,038)	$ (41,976)
Net loss	(91,710)	(93,772)
Basic earnings per share	(0.55)	(0.56)
Diluted earnings per share	(0.55)	(0.56)

In addition, we have recorded a cumulative-effect adjustment to retained earnings (deficit) and reduced our deferred tax liability for $101.1 million for previously unrecognized tax benefits due to our NOL position.

Forfeitures - Prior to adoption, share-based compensation expense was recognized on a straight line basis, net of estimated forfeitures, such that expense was recognized only for share-based awards that are expected to vest. We have elected to continue to estimate forfeitures.

Statements of cash flows - The presentation requirements for cash flows related to employee taxes paid for withheld shares will be adjusted retrospectively. These cash flows have historically been presented as an operating activity. Upon adoption of this new standard, these cash outflows will be classified as a financing activity. Prior periods have been adjusted as follows (in thousands):

	As Reported	As Adjusted
	Net cash provided from operating activities	Net cash provided from operating activities
Year ended 2015	$ 683,700	$ 691,402
Year ended 2014	954,135	974,353
Year ended 2013	743,538	757,373
Three months ended March 31, 2016	87,424	90,785
Six months ended June 30, 2016	169,604	173,201
Nine months ended September 30, 2016	202,037	205,837

	As Reported	As Adjusted
	Net cash (used in) provided from financing activities	Net cash (used in) provided from financing activities
Year ended 2015	$ (464,905)	$ (472,607)
Year ended 2014	291,421	271,203
Year ended 2013	239,994	226,159
Three months ended March 31, 2016	(72,473)	(75,834)
Six months ended June 30, 2016	(95,411)	(99,008)
Nine months ended September 30, 2016	(35,229)	(39,029)

In July 2015, an accounting standards update was issued that requires an entity to measure inventory at the lower of cost or net realizable value. This excludes inventory measured using LIFO or the retail inventory method. This standard was effective for us in first quarter 2017 and was applied prospectively. Adoption of this standard did not have an impact on our consolidated results of operations, financial position or cash flows.

In August 2016, an accounting standards update was issued that clarifies how entities classify certain cash receipts and cash payments on the statement of cash flows. The guidance is effective for us in first quarter 2018 and should be applied retrospectively with early adoption permitted. We adopted this new standard in the fourth quarter 2017 on a retrospective basis. Adoption of this standard did not have an impact on our consolidated cash flow statement presentation.

In January 2017, an accounting standards update was issued which clarifies the definition of a business. This new standard is effective for us in first quarter 2018 with early adoption permitted. We adopted this new standard in the fourth quarter 2017. Adoption of this standard did not have a significant impact on our consolidated results of operations, financial position or cash flows.

Accounting Pronouncements Not Yet Adopted

In May 2014, an accounting standards update was issued that supersedes the existing revenue recognition requirements. This standard includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which we expect to be entitled in exchange for those goods or services. Among other things, the standard also eliminates industry-specific revenue guidance, requires enhanced disclosures about revenue, provides guidance for transactions that were not previously addressed comprehensively and improves guidance for multiple-element arrangements. This standard is effective for us in first quarter 2018 and we expect to adopt the new standard using the modified retrospective method of adoption. We have utilized a bottom-up approach to analyze the impact of the new standard on our contracts by reviewing our current accounting policies and practices to identify potential differences that would result from applying the requirements of the new standard to our revenue contracts and the impact of adopting this standards update on our total revenues, operating income (loss) and our consolidated balance sheet. As of December 31, 2017, we have substantially completed our evaluation of our sources of revenue and the impact of this accounting standards update on our consolidated results of operations, financial position, cash flows and financial disclosures, in addition to developing and implementing any process or control changes necessary. We do not expect to record a cumulative effect adjustment on date of adoption; however, our financial statement presentation related to revenue received from certain gas processing contracts will change. Based on current accounting guidance, certain of our gas processing contracts are reported in revenue at the net price (net of processing costs) we receive. Upon adoption of this accounting standards update, these contracts will be reported as a gross price received at a delivery point and additional transportation, marketing and processing expense.

In February 2016, an accounting standards update was issued that requires an entity to recognize a right-of-use asset and lease liability for all leases with terms of more than twelve months. Classification of leases as either a finance or operating lease will determine the recognition, measurement and presentation of expenses. This accounting standards update also requires certain quantitative and qualitative disclosures about leasing arrangements. This standards update is effective for us in first quarter 2019 and should be applied using a modified retrospective approach for leases that exist or are entered into after the beginning of the earliest comparative period in the financial statements, with early adoption is permitted. We are evaluating the provisions of this accounting standards update and assessing the impact it will have on our consolidated results of operations, financial position or cash flows but based on our preliminary review of the update, we expect that we will have operating leases with durations greater than twelve months on the balance sheet. As we continue to evaluate and implement the standards update, we will provide additional information about the expected financial impact at a future date.

In June 2016, an accounting standards update was issued that changes the impairment model for trade receivables, net investments in leases, debt securities, loans and certain other instruments. The standards update requires the use of a forward-looking "expected loss" model as opposed to the current "incurred loss" model. This standards update is effective for us in first quarter 2020 and will be adopted on a modified retrospective basis though a cumulative-effect adjustment to retained earnings as of the beginning of the adoption period. Early adoption is permitted starting January 2019. We are evaluating the provisions of this accounting standards update and assessing the impact, if any, it may have on our consolidated results of operations, financial position or cash flows.

In March 2017, an accounting standards update was issued which provides additional guidance on the presentation of net benefit cost in the statement of operations. Employers will present the service cost component of net periodic benefit cost in the same consolidated results of operations line item as other employee compensation costs rising from services rendered during the period. This new standards update will be effective for us for annual reporting periods in first quarter 2018, with early adoption permitted. We anticipate this standard will not have a material impact on our financial statements and related disclosures.

In May 2017, an accounting standards update was issued which clarifies what constitutes a modification of a share-based award. This standards update is intended to provide clarity and reduce both diversity in practice and cost and complexity to a change to the terms or conditions of a share-based payment award. This standards update will be effective for us in first quarter 2018 and we do not anticipate it will have a material impact on our financial position or consolidated results of operations.

(3) Dispositions and Acquisitions

We recognized a pretax net gain on the sale of assets of $23.7 million in the year ended December 31, 2017 compared to a loss of $7.1 million in 2016 and a loss of $406.9 million in 2015. The following describes the significant divestitures that are included in our consolidated results of operations for each of three years ended December 31, 2017, 2016 and 2015.

2017 Dispositions

Texas Panhandle. In fourth quarter 2017, we sold various properties in the Texas Panhandle for proceeds of $40.4 million and we recorded a loss of $989,000 related to this sale, after closing adjustments.

Western Oklahoma. In the year ended December 31, 2017, we sold certain properties in Oklahoma for proceeds of $30.8 million and we recorded a gain of $23.8 million related to this sale, after closing adjustments and transaction fees.

Other. In 2017, we sold miscellaneous unproved property, inventory and surface property for proceeds of $1.3 million resulting in a gain of $870,000.

2016 Dispositions

Western Oklahoma. In first nine months 2016, we sold various properties in Western Oklahoma for proceeds of $78.6 million and we recorded a loss of $5.3 million related to these sales, after closing adjustments and transaction fees.

Pennsylvania. In first quarter 2016, we sold our non-operated interest in certain wells and gathering facilities in northeast Pennsylvania for proceeds of $111.5 million. After closing adjustments, we recorded a loss of $2.1 million related to this sale.

Other. In 2016, we sold miscellaneous proved and unproved property, inventory and surface property for proceeds of

$3.7 million resulting in a gain of $302,000. Included in the $3.7 million of proceeds is $1.2 million received from the sale of proved properties in Mississippi and South Texas.

2015 Dispositions

Virginia and West Virginia. In December 2015, we sold the majority of our producing properties and gathering assets in Virginia and West Virginia for cash proceeds of $876.0 million, before closing adjustments. We recorded a pretax loss of $407.7 million related to this sale. We recognized $52.3 million of field net operating income (defined as natural gas, oil and NGLs sales plus net brokered margin less direct operating expenses, production and ad valorem taxes, transportation expense, exploration expense and divisional office general and administrative expense) for these assets for the period from January 1, 2015 to December 30, 2015.

West Texas. In February 2015, we sold certain of our West Texas properties for cash proceeds of $10.5 million and we recognized a pretax loss of $101,000 related to this sale.

Other. During 2015, we also sold miscellaneous inventory, surface acreage and unproved property for proceeds of $4.4 million which resulted in a pretax gain of $943,000.

Memorial Merger

On September 16, 2016, we completed the MRD Merger which was accomplished through the merger of Medina Merger Sub, Inc., a Delaware corporation and a direct, wholly-owned subsidiary of Range, with and into Memorial, with Memorial surviving as a wholly-owned subsidiary of Range. The results of Memorial's operations since the effective time of the merger are included in our consolidated statement of operations. The merger was effected through the issuance of approximately 77.0 million shares of Range common stock in exchange for all outstanding shares of Memorial using an exchange ratio of 0.375 of a share of Range common stock for each share of Memorial common stock. At the effective time of the merger, Memorial's liabilities, which are reflected in Range's consolidated financial statements, included approximately $1.2 billion fair value of outstanding debt. In connection with the MRD Merger, we incurred merger-related expenses of approximately $37.2 million including consulting, investment banking, advisory, legal and other merger-related fees.

Allocation of Purchase Price. The MRD Merger has been accounted for as a business combination, using the acquisition method. The following table represents the final allocation of the total purchase price of the MRD Merger to the assets acquired and the liabilities assumed based on the fair value at the effective time of the merger, with any excess of the purchase price over the estimated fair value of the identifiable net assets acquired recorded as goodwill (in thousands, except shares and stock price):

Purchase price:		
Shares of Range common stock issued to Memorial stockholders		77,042,749
Range common stock price per share at September 15, 2016 (close)	$	39.37
Total purchase price	$	3,033,173
Plus fair value of liabilities assumed by Range:		
Accounts payable	$	55,624
Other current liabilities		108,367
Long-term debt		1,204,449
Deferred taxes		547,706
Other long-term liabilities		77,223
Total purchase price plus liabilities assumed	$	5,026,542
Fair value of Memorial assets:		
Cash and equivalents	$	7,180
Other current assets		99,969
Derivative instruments		152,994
Natural gas and oil properties:		
Proved property		1,122,311
Unproved property		1,999,187
Other property and equipment		3,579
Goodwill [a]		1,641,197
Other		125
Total asset value	$	5,026,542

[a] Goodwill will not be deductible for income tax purposes.

The fair value measurements of derivative instruments assumed were determined based on published forward commodity price curves as of the date of the MRD Merger and represent Level 2 inputs. Derivative instruments in an asset position include a measure of counterparty nonperformance risk and the fair values of commodity derivative instruments in a liability position include a measure of our own nonperformance risk, each based on the current published credit default swap rates. The fair value measurements of long-term debt were estimated based on published market prices and represent Level 1 inputs.

The fair value measurements of natural gas and oil properties and asset retirement obligations are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair value of natural gas and oil properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of natural gas and oil properties include estimates of: (i) recoverable reserves, (ii) production rates, (iii) future operating and development costs, (iv) future commodity prices and (v) a market-based weighted average costs of capital rate. These inputs require significant judgments and estimates by management at the time of the valuation and may be subject to change. Management utilized the assistance of a third party valuation expert to estimate the value of natural gas and oil properties acquired. In some cases, certain amounts allocated to unproved properties are based on a market approach using third party published data which provides lease pricing information based on certain geographic areas and represent Level 2 inputs.

Goodwill is attributed to net deferred tax liabilities arising from the differences between the purchase price allocated to Memorial's assets and liabilities based on fair value and the tax basis of these assets and liabilities. In addition, the total consideration for the merger included a control premium, which resulted in a higher value compared to the fair value of net assets acquired. There are also other qualitative assumptions of long-term factors that the merger creates including additional potential for exploration and development opportunities, additional scale and efficiencies in other basins in which we operate and substantial operating and administrative synergies.

The results of operations attributable to Memorial are included in our consolidated statements of operations beginning on September 16, 2016. We recognized $477.4 million of natural gas, oil and NGLs revenue and $278.8 million of field net operating income from these assets from January 1, 2017 to December 31, 2017. We recognized $146.6 million of natural gas, oil and NGLs revenues and $94.9 million of field net operating income from these assets from September 16, 2016 to December 31, 2016.

Pro forma Financial Information. The following pro forma condensed combined financial information was derived from the historical financial statements of Range and Memorial and gives effect to the merger as if it had occurred on January 1, 2015. The below information reflects pro forma adjustments for the issuance of Range common stock in exchange for Memorial's outstanding shares of common stock, as well as pro forma adjustments based on available information and certain assumptions that we believe are reasonable, including (i) the depletion of Memorial's fair-valued proved natural gas and oil properties and (ii) the estimated tax impacts of the pro forma adjustments. Additionally, pro forma earnings for the year ended December 31, 2016 were adjusted to exclude $37.2 million of merger-related costs incurred by Range and $7.1 million incurred by Memorial. The pro forma results of operations do not include any cost savings or other synergies that may result from the MRD Merger or any estimated costs that have been or will be incurred by us to integrate the Memorial assets. The pro forma condensed combined financial information has been included for comparative purposes and is not necessarily indicative of the results that might have actually occurred had the MRD Merger taken place on January 1, 2015. In addition, the pro forma financial information below is not intended to be a projection of future results (in thousands, except per share amounts).

	Year Ended December 31,	
	2016	2015
Revenues	$ 1,334,290	$ 2,253,368
Net loss	$ (591,121)	$ (556,164)
Loss per share:		
Basic	$ (2.42)	$ (2.28)
Diluted	$ (2.42)	$ (2.28)

(4) Goodwill

Our goodwill relates to the excess of purchase price over amounts assigned to assets and liabilities from the MRD Merger which is equal to $1.6 billion at December 31, 2017. We performed a quantitative impairment test during third quarter 2017 due to a sustained decline in our market capitalization. Management utilized the assistance of a third-party valuation expert to determine the fair value of our business (our reporting unit). The fair value was determined based on a combination of a market and an income approach. As a result of this measurement, the fair value of our business exceeded the carrying value of net assets and no impairment was recorded. As of this date, our fair value exceeded book value by $1.4 billion or 24%. After considering the impact of the new tax law, our fair value exceeded our book value by $2.4 billion or 42%. For additional information regarding the new tax law, see Note 5.

During fourth quarter 2017, we conducted a qualitative impairment assessment, by examining relevant events and circumstances which could have a negative impact on our business such as: macroeconomic conditions, industry and market conditions, including the downturn in the oil and gas industry, cost factors that could have a negative effect on earnings and cash flows, overall financial performance, dispositions and acquisitions, and other relevant entity-specific events. We identified various factors to consider including commodity prices, our year-end proved reserves evaluation and the market value of our common stock. Our analysis indicated that the fair value of our business was not below book value. Although we based the fair value estimate on assumptions we believe to be reasonable, those assumptions are inherently unpredictable and uncertain.

(5) Income Taxes

Our income tax benefit was $251.0 million for the year ended December 31, 2017 compared to $280.8 million in 2016 and $338.7 million in 2015. Reconciliation between the statutory federal income tax rate and our effective income tax rate is as follows:

	Year Ended December 31,		
	2017	2016	2015
Federal statutory tax rate	35.0%	35.0%	35.0%
Federal rate change	(406.7)	—	—
State	(0.7)	3.0	4.3
State rate and law change	(1.3)	1.0	(0.2)
Non-deductible executive compensation	0.7	(0.2)	(0.1)
Non-deductible MRD transaction costs	—	(0.6)	—
Valuation allowances	36.8	(2.5)	(6.8)
Equity compensation	30.2	(0.7)	—
Other	0.3	—	—
Consolidated effective tax rate	(305.7%)	35.0%	32.2%

Income tax (benefit) expense attributable to income before income taxes consists of the following (in thousands):

	2017			2016			2015		
	Current	Deferred	Total	Current	Deferred	Total	Current	Deferred	Total
U.S. federal	$ —	$ (302,507)	$ (302,507)	$ —	$ (266,105)	$ (266,105)	$ —	$ (328,257)	$ (328,257)
U.S. state and local	17	51,464	51,481	98	(14,743)	(14,645)	29	(10,449)	(10,420)
Total	$ 17	$ (251,043)	$ (251,026)	$ 98	$ (280,848)	$ (280,750)	$ 29	$ (338,706)	$ (338,677)

Significant components of deferred tax assets and liabilities are as follows:

	December 31, 2017	December 31, 2016
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforward	$ 413,672	$ 478,203
Deferred compensation	24,704	50,808
Equity compensation	5,269	29,528
AMT credits and other credits	7,264	13,644
Asset retirement obligation	69,398	99,000
Cumulative mark-to-market loss	—	73,404
Other	18,806	39,922
Valuation allowances:		
Federal	(31,308)	(48,750)
State, net of federal benefit	(93,826)	(58,424)
Total deferred tax assets	413,979	677,335
Deferred tax liabilities:		
Depreciation, depletion and investments	(1,105,494)	(1,619,922)
Cumulative mark-to-market gain	(1,841)	—
Other	—	(756)
Total deferred tax liabilities	(1,107,335)	(1,620,678)
Net deferred tax liability	$ (693,356)	$ (943,343)

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 was signed into law. The law significantly reforms the Internal Revenue Code of 1986, as amended. The reduction in the corporate tax rate required a one-time revaluation of certain tax related assets and liabilities to reflect their value at the lower corporate tax rate of 21%. We reviewed all of the valuation allowances previously established at the corporate rate of 35% to reflect the appropriate new balances after the enactment of the new law. A one-time tax benefit was recorded related to the tax law changes in the amount of $334.0 million. Due to the complexities involved in accounting for the enactment of the new law, the SEC Staff Accounting Bulletin ("SAB") 118 allows us to provide a provisional estimate for the year ending December 31, 2017. As of December 31, 2017, we have not completed our accounting for the tax effects of the new law and its impact on our deferred tax balances. We have made a reasonable estimate of the effect on our deferred tax balances. We will continue to analyze the impact of the new law and additional impacts will be recorded as they are identified during the measurement period as provided for in SAB 118.

At December 31, 2017, deferred tax liabilities exceeded deferred tax assets by $693.4 million. As of December 31, 2017, we have a valuation allowance of $1.9 million on the deferred tax asset related to our deferred compensation plan for planned future distributions to certain executives to the extent that their estimated future compensation plus distribution amounts would exceed the $1.0 million deductible limit provided under I.R.C. Section 162(m). As of December 31, 2017, we have a state valuation allowance of $36.3 million related to state tax attributes in Oklahoma, Texas and West Virginia. During 2017, we adjusted our valuation allowance related to our Pennsylvania state tax attributes to be $57.5 million due to the low commodity price environment and the limitation Pennsylvania places on future utilization of net operating loss carryforwards.

On October 18, 2017, the Supreme Court of Pennsylvania issued a decision on a case related to limiting net operating loss deductions to the greater of $3.0 million or 30 percent of taxable income. The Supreme Court ruled that the net operating loss deduction limitation violated the Uniformity Clause of the Pennsylvania Constitution and struck the $3.0 million flat cap limitation but not the percentage of taxable income limitation.

The changes in our deferred tax asset valuation allowances are as follows (in thousands):

	2017	2016	2015
Balance at the beginning of the year	$ (107,174)	$ (87,623)	$ (16,599)
Charged to provision for income taxes:			
State net operating loss carryforwards	(11,612)	(17,374)	(30,457)
Federal net operating carryforwards	15,385	(1,100)	(42,500)
Other state valuation allowances	(23,790)	500	(1,050)
Other federal valuation allowances	(247)	(477)	(511)
Rabbi trust valuation allowance	2,304	(1,066)	3,494
Other	—	(34)	—
Balance at the end of the year	$ (125,134)	$ (107,174)	$ (87,623)

At December 31, 2017, we had federal net operating loss ("NOL") carryforwards of $1.5 billion that expire between 2018 and 2035 and an NOL in Pennsylvania of $872.6 million that expire between 2025 and 2036. We file consolidated tax returns in the United States federal jurisdiction. We file separate company state income tax returns in Louisiana, Pennsylvania and Virginia and file consolidated or unitary state income tax returns in Oklahoma, Texas and West Virginia. We are subject to U.S. Federal income tax examinations for the years 2013 and after and we are subject to various state tax examinations for years 2012 and after. We have not extended the statute of limitation period in any income tax jurisdiction. Our policy is to recognize interest related to income tax expense on interest expense and penalties in general and administrative expense. We do not have any accrued interest or penalties related to tax amounts as of December 31, 2017. Throughout 2017, our unrecognized tax benefits were not material.

(6) Net Income (Loss) per Common Share

Basic income or loss per share attributable to common stockholders is computed as (i) income or loss attributable to common stockholders (ii) less income allocable to participating securities (iii) divided by weighted average basic shares outstanding. Diluted income or loss per share attributable to common stockholders is computed as (i) basic income or loss attributable to common stockholders (ii) plus diluted adjustments to income allocable to participating securities (iii) divided by weighted average diluted shares outstanding. Diluted net income (loss) per share is calculated under both the two class method and the treasury stock method and the more dilutive of the two calculations is presented. The following table sets forth a reconciliation of net income or loss to basic income or loss attributable to common stockholders and to diluted income or loss attributable to common stockholders (in thousands except per share amounts):

	Year Ended December 31,		
	2017	2016	2015
Net income (loss), as reported	$ 333,146	$ (521,388)	$ (713,685)
Participating basic earnings [(a)]	(3,751)	(223)	(450)
Basic net income (loss) attributed to common stockholders	329,395	(521,611)	(714,135)
Reallocation of participating earnings [(a)]	5	—	—
Diluted net income (loss) attributed to common stockholders	$ 329,400	$ (521,611)	$ (714,135)
Net income (loss) per common share:			
Basic	$ 1.34	$ (2.75)	$ (4.29)
Diluted	$ 1.34	$ (2.75)	$ (4.29)

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

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

	Year Ended December 31,		
	2017	2016	2015
Denominator:			
Weighted average common shares outstanding – basic [(1)]	245,091	189,868	166,389
Effect of dilutive securities:			
Director and employee restricted stock and performance-based equity awards	367	—	—
Weighted average common shares outstanding – diluted	245,458	189,868	166,389

(1) Includes common stock issued in connection with the exchange of 77.0 million shares for all outstanding Memorial common stock on September 16, 2016.

Weighted average common shares – basic excludes 2.8 million shares of restricted stock Liability Awards held in our deferred compensation plans (although all awards are issued and outstanding upon grant) for each of the periods ending December 31, 2017, 2016 and 2015. Due to our net loss for the years ended December 31, 2016 and 2015, we excluded all outstanding equity grants from the computation of diluted net loss per share because the effect would have been anti-dilutive to the computations. Equity grants of 702,000 for the year ended December 31, 2017 were outstanding but not included in the computations of diluted net income per share because the grant prices were greater than the average market price of the common shares and would be anti-dilutive to the computations. For purposes of calculating diluted weighted average common shares for the year ended December 31, 2017, nonvested restricted stock and performance – based equity awards are included in the computation using the treasury stock method with the deemed proceeds equal to the average unrecognized compensation during the period.

(7) Suspended Exploratory Well Costs

We capitalize exploratory well costs until a determination is made that the well has either found proved reserves or that it is impaired. Capitalized exploratory well costs are presented in natural gas and oil properties in the accompanying consolidated balance sheets. If an exploratory well is determined to be impaired, the well costs are charged to exploration expense in the accompanying consolidated statements of operations. The following table reflects the changes in capitalized exploratory well costs for the years ended December 31, 2017, 2016 and 2015 (in thousands, except for number of projects):

	2017	2016	2015
Balance at beginning of period	$ 7,412	$ 4,161	$ 2,996
Additions to capitalized exploratory well costs pending the determination of proved reserves	1,388	9,128	1,165
Reclassifications to wells, facilities and equipment based on determination of proved reserves	—	(5,877)	—
Capitalized exploratory well costs charged to expense	(8,800)	—	—
Balance at end of period	—	7,412	4,161
Less exploratory well costs that have been capitalized for a period of one year or less	—	(7,412)	(1,165)
Capitalized exploratory well costs that have been capitalized for a period greater than one year	$ —	$ —	$ 2,996
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	—	—	1

(8) Indebtedness

We had the following debt outstanding as of the dates shown below (in thousands) (bank debt interest rate at December 31, 2017 is shown parenthetically). The expenses of issuing debt are capitalized and included as a reduction to debt in the accompanying consolidated balance sheets. These costs are amortized over the expected life of the related instruments. When debt is retired before maturity, or modifications significantly change the cash flows, the related unamortized costs are expensed. No interest was capitalized during 2017, 2016, and 2015.

	December 31, 2017	December 31, 2016
Bank debt (3.0%)	$ 1,211,000	$ 882,000
Senior notes		
4.875% senior notes due 2025	750,000	750,000
5.00% senior notes due 2023	741,531	741,531
5.00% senior notes due 2022	580,032	580,032
5.75% senior notes due 2021	475,952	475,952
5.875% senior notes due 2022 [a]	329,244	329,244
Other senior notes due 2022 [b]	590	1,090
Total senior notes	2,877,349	2,877,849
Senior subordinated notes		
5.00% senior subordinated notes due 2023	7,712	7,712
5.00% senior subordinated notes due 2022	19,054	19,054
5.75% senior subordinated notes due 2021	22,214	22,214
Total senior subordinated notes	48,980	48,980
Total debt	4,137,329	3,808,829
Unamortized premium	6,027	7,241
Unamortized debt issuance costs	(34,550)	(42,553)
Total debt net of debt issuance costs	$ 4,108,806	$ 3,773,517

[a] Represents senior notes assumed in the MRD Merger that were not purchased for cash but were exchanged for Range 5.875% senior notes due 2022. See Senior Notes Exchange and Cash Tender Offer below.

[b] Represents the remaining Memorial 5.875% senior notes assumed in the MRD Merger that were not purchased for cash or were not exchanged for Range 5.875% senior notes due 2022. See Senior Notes Exchange and Cash Tender Offer below.

Bank Debt

In October 2014, we entered into an amended and restated revolving bank facility, which we refer to as our bank debt or our bank credit facility, which is secured by substantially all of our assets. The bank credit facility has a maximum facility amount of $4.0 billion. As of December 31, 2017, the facility had a borrowing base of $3.0 billion and bank commitments of $2.0 billion. The bank credit facility provides for a borrowing base subject to redeterminations annually by each May and for event-driven unscheduled redeterminations. As part of our annual redetermination completed on March 21, 2017, our borrowing base was reaffirmed at $3.0 billion and our bank commitment was also reaffirmed at $2.0 billion. Our current bank group is comprised of twenty-nine financial institutions, with no one bank holding more than 5.8% of the total facility. The borrowing base may be increased or decreased based on our request and sufficient proved reserves, as determined by the bank group. The commitment amount may be increased to the borrowing base, subject to payment of a mutually acceptable commitment fee to those banks agreeing to participate in the facility increase. The commitment matures on October 16, 2019. As of December 31, 2017, the outstanding balance under the bank credit facility was $1.2 billion with $281.4 million of undrawn letters of credit leaving $507.6 million of borrowing capacity available under the commitment amount. During a non-investment grade period, borrowings under the bank facility can either be at the alternate base rate ("ABR," as defined in the bank credit agreement) plus a spread ranging from 0.25% to 1.25% or LIBOR borrowings at the LIBOR Rate (as defined in the bank credit agreement) plus a spread ranging from 1.25% to 2.25%. The applicable spread is dependent upon borrowings relative to the borrowing base. We may elect, from time to time, to convert all or any part of our LIBOR loans to ABR loans or to convert all or any part of our ABR loans to LIBOR loans. The weighted average interest rate was 2.7% for the year ended December 31, 2017 compared to 2.2% for the year ended December 31, 2016 and 1.7% for the year ended December 31, 2015. A commitment fee is paid on the undrawn balance based on an annual rate of 0.30% to 0.375%. At December 31, 2017, the commitment fee was 0.3%, the interest rate margin was 1.5% on our LIBOR loans and 0.5% on our ABR.

At any time during which we have an investment grade debt rating from Moody's Investors Service, Inc. or Standard & Poor's Ratings Services and we have elected, at our discretion, to effect the investment grade rating period, certain collateral security requirements, including the borrowing base requirement and restrictive covenants will cease to apply, certain other restrictive covenants will become less restrictive and an additional financial covenant (as defined in the bank credit facility) will be temporarily imposed. During the investment grade period, borrowings under the bank credit facility can either be at the ABR plus a spread ranging from 0.125% to 0.75% or LIBOR Rate plus a spread ranging from 1.125% to 1.75% depending on our debt rating. The commitment fee paid on the undrawn balance ranges from 0.15% to 0.30%. We currently do not have an investment grade rating.

Senior Notes

In September 2016, in conjunction with MRD Merger, we issued $329.2 million senior unsecured 5.875% notes due 2022 (the "5.875% Notes") (See also *Senior Notes Exchange and Cash Tender Offer* below). In addition, we also completed a debt exchange offer to exchange senior subordinated notes for the following senior notes. (See also *Senior Subordinated Notes Exchange* below) (in thousands):

	Principal Amount
5.00% senior notes due 2023	$ 741,531
5.00% senior notes due 2022	$ 580,032
5.75% senior notes due 2021	$ 475,952

All of the notes were offered to qualified institutional buyers and to non-U.S. persons outside the United States in compliance with Rule 144A and Regulation S under the Securities Act of 1933, as amended (the "Securities Act"). On October 5, 2017, the 5.875% Notes, the 5.00% senior notes due 2023, the 5.00% senior notes due 2022 and the 5.75% senior notes due 2021 (collectively, the "Old Notes") were exchanged for an equal principal amount of registered notes pursuant to an effective registration statement on Form S-4 filed with the SEC on August 9, 2017 under the Securities Act (the "New Notes"). The New Notes are identical to the Old Notes except the New Notes are registered under the Securities Act and do not have restrictions on transfer, registration rights or provisions for additional interest. Under certain circumstances, if we experience a change of control, noteholders may require us to repurchase all of our senior notes at 101% of the aggregate principal amount plus accrued and unpaid interest, if any.

In May 2015, we issued $750.0 million aggregate principal amount of 4.875% senior notes due 2025 (the "Outstanding Notes") for net proceeds of $737.4 million after underwriting discounts and commissions of $12.6 million. The notes were issued at par and were offered to qualified institutional buyers and non-U.S. persons outside the United States in compliance with Rule 144A and Regulation S under the Securities Act. On April 8, 2016, all of the Outstanding Notes were exchanged for an equal principal amount of registered 4.875% senior notes due 2025 pursuant to an effective registration statement on Form S-4 filed with the SEC on February 29, 2016 under the Securities Act (the "Exchange Notes"). The Exchange Notes are identical to the Outstanding Notes except the Exchange Notes are registered under the Securities Act and do not have restrictions on transfer, registration rights or provisions for additional interest. Under certain circumstances, if we experience a change of control, noteholders may require us to repurchase all of our senior notes at 101% of the aggregate principal amount plus accrued and unpaid interest, if any.

Senior Notes Exchange and Cash Tender Offer

On September 16, 2016, we completed a debt exchange offer to exchange all validly tendered and accepted Memorial senior notes assumed in the MRD Merger. We exchanged 54.9% of the outstanding Memorial senior notes, whereby we issued the 5.875% Notes. The 5.875% Notes were offered to qualified institutional buyers and to non-U.S. persons outside the United States in compliance with Rule 144A and Regulation S under the Securities Act. Interest on the 5.875% Notes is payable in January and July. The 5.875% Notes will mature on July 1, 2022 and are unconditionally guaranteed on a senior unsecured basis by all of our subsidiary guarantors. On or after April 1, 2022, we may redeem the 5.875% Notes in whole or in part and from time to time, at 100% of the principal amount, plus accrued and unpaid interest. The 5.875% Notes are unsecured and are subordinated to all of our existing and future secured debt, rank equally with all of our existing and future senior unsecured debt and rank senior to all of our existing and future subordinated debt. The deferred financing cost for this exchange was $6.3 million. The early cash tender premium paid was $4.1 million, which was paid to note holders who tendered their notes within the ten business day early offer period.

Also on September 16, 2016, we completed our concurrent offer to purchase for cash the Memorial senior notes assumed in the MRD Merger. We acquired 44.9% of the outstanding Memorial senior notes, or $269.7 million principal amount of the senior notes assumed in the MRD Merger, which we purchased for cash. The early cash tender premium paid was $3.3 million which was paid to note holders who tendered their notes within the ten business day early offer period. The cash tender offer and early cash tender premium were financed with borrowings under our bank credit facility. Concurrently with the Memorial senior note exchange offer and cash tender offer, we also solicited consents from the eligible holders to amend the indenture that governed the existing Memorial senior notes. The amendments included eliminating certain of the covenants, restrictive provisions, reporting requirements and events of default. Once a majority of consents were received, the amendments were accepted for all existing Memorial senior note holders, even if the senior notes were not tendered in either the exchange offer or cash tender offer.

Senior Subordinated Notes Exchange

On September 16, 2016, we also completed our debt exchange offer to exchange all validly tendered and accepted Range senior subordinated notes as detailed below (in thousands):

Existing Note	New Note	Principal Amount of Notes Validly Tendered [(1)]	Approximate Percentage Validly Tendered
5.00% senior subordinated notes due 2023	5.00% senior notes due 2023	$742,291	99.0%
5.00% senior subordinated notes due 2022	5.00% senior notes due 2022	$580,946	96.8%
5.75% senior subordinated notes due 2021	5.75% senior notes due 2021	$477,786	95.6%

(1) Prior to exchange premium

We recorded $6.6 million of third party costs in interest expense in third quarter 2016 related to this exchange. The new senior notes were issued at par and were offered to qualified institutional buyers and non-U.S. persons outside the United States in compliance with Rule 144A and Regulation S under the Securities Act. A $3.5 million premium was recorded in connection with the exchange for certain holders that participated in the exchange after the early tender period and received 95% of face amount tendered in exchange consideration. Interest on the new 5.00% senior notes due 2023 is payable in March and September with a maturity date of March 15, 2023. Interest on the new 5.00% senior notes due 2022 is payable in February and August with a maturity date of August 15, 2022. Interest on the new 5.75% senior notes due 2021 is payable in June and December with a maturity date of June 1, 2021. All of the new senior notes are unconditionally guaranteed on a senior unsecured basis by all of our subsidiary guarantors. The new senior notes are unsecured and are subordinated to all of our existing and future senior secured debt and rank senior to all of our existing and future subordinated debt. Under certain circumstances, if we experience a change of control, noteholders may require us to repurchase all of our senior notes at 101% of the aggregate principal amount plus accrued and unpaid interest, if any. Concurrently with the senior subordinated notes exchange offer, we also solicited consents from the eligible holders to amend the indentures that governed each of the existing senior subordinated notes. The amendments included eliminating certain of the covenants, restrictive provisions, reporting requirements and events of default. Once a majority of consents were received, the amendments were accepted for all senior subordinated note holders, even if the remaining senior subordinated notes were not exchanged.

Senior Subordinated Notes

If we experience a change of control, noteholders may require us to repurchase all or a portion of our senior subordinated notes at 101% of the principal amount plus accrued and unpaid interest, if any. All of the senior subordinated notes and the guarantees by our subsidiary guarantors are general, unsecured obligations and are subordinated to our bank debt and to existing and future senior debt that we or our subsidiary guarantors are permitted to incur.

Early Extinguishment of Debt

In July 2015, we announced a call for the redemption of $500.0 million of our outstanding 6.75% senior subordinated notes due 2020 at a price of 103.375% of par plus accrued and unpaid interest, which were redeemed on August 3, 2015. In the year ended 2015, we recognized a loss on early extinguishment of debt of $22.5 million, including transaction call premium costs and the expensing of the remaining deferred financing costs on the repurchased debt.

Guarantees

Range Resources Corporation is a holding company which owns no operating assets and has no significant operations independent of its subsidiaries. The guarantees by our wholly-owned subsidiaries, which are directly or indirectly owned by Range, of our senior notes, our senior subordinated notes and our bank credit facility are full and unconditional and joint and several, subject to certain customary release provisions. A subsidiary guarantor may be released from its obligations under the guarantee:

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

Debt Covenants and Maturity

Our bank credit facility contains negative covenants that limit our ability, among other things, to pay cash dividends, incur additional indebtedness, sell assets, enter into certain hedging contracts, change the nature of our business or operations, merge, consolidate, or make certain investments. In addition, we are required to maintain a ratio of EBITDAX (as defined in the credit agreement) to cash interest expense of equal to or greater than 2.5 and a current ratio (as defined in the credit agreement) of no less than 1.0. In addition, the ratio of the present value of proved reserves (as defined in the credit agreement) to total debt must be equal to or greater than 1.5 until Range has two investment grade ratings. We were in compliance with applicable covenants under the bank credit facility at December 31, 2017.

The following is the principal maturity schedule for our long-term debt outstanding as of December 31, 2017 (in thousands):

	Year Ended December 31,
2018	$ —
2019	1,211,000
2020	—
2021	498,166
2022	928,920
Thereafter	1,499,243
	$ 4,137,329

(9) Asset Retirement Obligations

Our asset retirement obligations primarily represent the present value of the estimated amounts we will incur to plug, abandon and remediate our producing properties at the end of their productive lives. Significant inputs used in determining such obligations include estimates of plugging and abandonment costs, estimated future inflation rates and well life. The inputs are calculated based on historical data as well as current estimated costs. The following is a reconciliation of our liability for plugging and abandonment costs as of December 31, 2017 and 2016 (in thousands):

	2017	2016
Beginning of period	$ 257,943	$ 264,137
Liabilities incurred	7,724	2,694
Acquisitions	—	21,900
Liabilities settled	(7,965)	(11,511)
Disposition of wells	(8,078)	(10,540)
Accretion expense	14,711	18,021
Change in estimate	12,520	(26,758)
End of period	276,855	257,943
Less current portion	(6,327)	(7,271)
Long-term asset retirement obligations	$ 270,528	$ 250,672

Accretion expense is recognized as an increase to depreciation, depletion and amortization expense in the accompanying consolidated statements of operations.

(10) Capital Stock

We have authorized capital stock of 485.0 million shares, which includes 475.0 million shares of common stock and 10.0 million shares of preferred stock. The following is a schedule of changes in the number of common shares outstanding since the beginning of 2015:

	Year Ended December 31,		
	2017	2016	2015
Beginning balance	247,144,356	169,316,460	168,628,177
MRD Merger	—	77,042,749	—
Stock options/SARs exercised	—	—	77,002
Restricted stock grants	539,096	490,609	335,103
Restricted stock units vested	344,937	266,541	252,507
Performance stock units issued	85,461	—	—
Shares retired	—	(739)	—
Treasury shares	15,580	28,736	23,671
Ending balance	248,129,430	247,144,356	169,316,460

Common Stock Dividends

The board of directors declared quarterly dividends of $0.02 per common share for each of the four quarters of 2017 and 2016. The board of directors declared quarterly dividends of $0.04 per common share for each of the four quarters of 2015. The determination of the amount of future dividends, if any, to be declared and paid is at the sole discretion of the board of directors and will depend on our financial condition, earnings, capital requirements, levels of indebtedness, our future business prospects and other matters our board of directors deem relevant. Our bank credit facility and our senior subordinated notes allow for the payment of common dividends, with certain limitations.

(11) Derivative Activities

We use commodity-based derivative contracts to manage exposure to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. We do not utilize complex derivatives as we typically utilize commodity swap, swaptions or collar contracts to (1) reduce the effect of price volatility of the commodities we produce and sell and (2) support our annual capital budget and expenditure plans. Every derivative instrument is required to be recorded on the balance sheet as either an asset or a liability measured at its fair value. Their fair value, which is represented by the estimated amount that would be realized upon termination, based on a comparison of the contract price and a reference price (generally NYMEX for natural gas and crude oil or Mont Belvieu for NGLs), approximated a net derivative asset of $13.6 million at December 31, 2017. These contracts expire monthly through December 2019. The following table sets forth the derivative volumes by year as of December 31, 2017, excluding our basis and freight swaps which are discussed separately below:

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price
Natural Gas			
2018	Swaps	794,822 Mmbtu/day	$ 3.13
2019	Swaps	12,329 Mmbtu/day	$ 3.01
January − March 2018	Collars	60,000 Mmbtu/day	$ 3.40-$ 3.76
April – December 2018	Swaptions	307,500 Mmbtu/day	$ 2.98 [1]
2019	Swaptions	85,000 Mmbtu/day	$ 2.97 [1]
Crude Oil			
2018	Swaps	8,995 bbls/day	$ 53.30
2019	Swaps	4,746 bbls/day	$ 52.81
NGLs (C2-Ethane)			
2018	Swaps	250 bbls/day	$ 0.29/gallon
NGLs (C3-Propane)			
2018	Swaps	10,362 bbls/day	$ 0.68/gallon
2018	Collars	2,000 bbls/day	$ 0.90-$ 1.05/gallon
NGLs (NC4-Normal Butane)			
2018	Swaps	4,621 bbls/day	$ 0.81/gallon
NGLs (C5-Natural Gasoline)			
2018	Swaps	4,713 bbls/day	$ 1.19/gallon
2019	Swaps	1,000 bbls/day	$ 1.24/gallon

[1] Contains a combined derivative instrument consisting of a fixed price swap and a sold option to extend or double the volume. For April through December 2018, we have swaps in place for 147,500 Mmbtu per day on which the counterparty can elect to double the volume at a weighted average price of $2.89. We also have swaps in place for 160,000 Mmbtu per day on which the counterparty can elect to extend the contract through December 2019 at a weighted average price of $3.07. In 2019, if the counterparty elects to double the volume, we would have additional swaps covering 85,000 Mmbtu per day at a weighted average price of $2.97.

Basis Swap Contracts

In addition to the swaps, collars and swaptions above, at December 31, 2017, we had natural gas basis swap contracts which lock in the differential between NYMEX and certain of our physical pricing points in Appalachia. These contracts settle monthly through October 2019 and include a total volume of 120,892,500 Mmbtu. The fair value of these contracts was a net derivative liability of $7.8 million on December 31, 2017.

At December 31, 2017, we also had propane spread swap contracts which lock in the differential between Mont Belvieu and international propane indexes. The contracts settle monthly through December 2018 and include a total volume of 1,362,000 barrels. The fair value of these contracts was a net derivative liability of $1.2 million on December 31, 2017.

Freight Swap Contracts

In connection with our international propane sales, we utilize propane swaps. To further hedge our propane price, at December 31, 2017, we had freight swap contracts which lock in the freight rate for a specific trade route on the Baltic Exchange. These contracts settle monthly through December 2018 and cover 5,000 metric tons per month with a fair value net derivative asset of $276,000 on December 31, 2017. These contracts use observable third-party pricing inputs that we consider to be Level 2 fair value classification.

Derivative assets and liabilities

The combined fair value of derivatives included in the accompanying consolidated balance sheets as of December 31, 2017 and 2016 is summarized below (in thousands). As of December 31, 2017, we are conducting derivative activities with nineteen counterparties, of which all but five are secured lenders in our bank credit facility. We believe all of these counterparties are acceptable credit risks. At times, such risks may be concentrated with certain counterparties. The credit worthiness of our counterparties is subject to periodic review. The assets and liabilities are netted where derivatives with both gain and loss positions are held by a single counterparty and we have master netting arrangements.

		December 31, 2017		
		Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet
Derivative assets:				
Natural gas	–swaps	$ 87,794	$ (4,106)	$ 83,688
	–swaptions	18,817	(8,103)	10,714
	–basis swaps	1,815	(6,673)	(4,858)
	–collars	3,039	(500)	2,539
Crude oil	–swaps	2	(7,928)	(7,926)
NGLs	–C2 ethane swaps	57	—	57
	–C3 propane swaps	—	(12,556)	(12,556)
	–C3 propane collars	85	(85)	—
	–C3 propane spread swaps	12,762	(12,762)	—
	–NC4 butane swaps	—	(6,051)	(6,051)
	–C5 natural gasoline swaps	—	(6,727)	(6,727)
Freight	–swaps	276	(276)	—
		$ 124,647	$ (65,767)	$ 58,880

		December 31, 2017		
		Gross Amounts of Recognized (Liabilities)	Gross Amounts Offset in the Balance Sheet	Net Amounts of (Liabilities) Presented in the Balance Sheet
Derivative (liabilities):				
Natural gas	–swaps	$ (216)	$ 4,106	$ 3,890
	–swaptions	(12,283)	8,103	(4,180)
	–basis swaps	(9,580)	6,673	(2,907)
	–collars	—	500	500
Crude oil	–swaps	(24,726)	7,928	(16,798)
NGLs	–C3 propane swaps	(34,325)	12,556	(21,769)
	–C3 propane collars	—	85	85
	–C3 propane spread swaps	(13,983)	12,762	(1,221)
	–NC4 butane swaps	(11,188)	6,051	(5,137)
	–C5 natural gasoline swaps	(13,488)	6,727	(6,761)
Freight	–swaps	—	276	276
		$ (119,789)	$ 65,767	$ (54,022)

		December 31, 2016		
		Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet
Derivative assets:				
Natural gas	–swaps	$ 13,213	$ (11,425)	$ 1,788
	–basis swaps	12,535	(9,437)	3,098
	–collars	6,298	(6,298)	—
	–puts	18,159	(15,429)	2,730
Crude oil	–swaps	9,356	(3,489)	5,867
NGLs	–C2 ethane swaps	53	(53)	—
	–C3 propane spread swaps	17,396	(17,396)	—
	–NC4 butane swaps	4	(4)	—
Freight	–swaps	65	(65)	—
		$ 77,079	$ (63,596)	$ 13,483

		December 31, 2016		
		Gross Amounts of Recognized (Liabilities)	Gross Amounts Offset in the Balance Sheet	Net Amounts of (Liabilities) Presented in the Balance Sheet
Derivative (liabilities):				
Natural gas	–swaps	$ (158,359)	$ 11,425	$ (146,934)
	–basis swaps	(687)	9,437	8,750
	–collars	(2,625)	6,298	3,673
	–puts	—	15,429	15,429
	–calls	(1,041)	—	(1,041)
Crude oil	–swaps	(13,206)	3,489	(9,717)
NGLs	–C2 ethane swaps	(1,008)	53	(955)
	–C3 propane swaps	(32,437)	—	(32,437)
	–C3 propane spread swaps	(18,138)	17,396	(742)
	–NC4 butane swaps	(13,419)	4	(13,415)
	–C5 natural gasoline swaps	(12,176)	—	(12,176)
Freight	–swaps	—	65	65
		$ (253,096)	$ 63,596	$ (189,500)

The effects of our derivatives on our consolidated statements of operations for the last three years are summarized below (in thousands).

	Year Ended December 31, Derivative Fair Value Income (Loss)		
	2017	2016	2015
Commodity Swaps	$ 181,095	$ (265,466)	$ 398,020
Swaptions	6,534	—	—
Re-purchased swaps	—	—	851
Collars	18,132	(6,926)	16,539
Basis swaps	(4,647)	29,154	954
Puts	10,929	(18,201)	—
Calls	987	(18)	—
Freight swaps	320	66	—
Total	$ 213,350	$ (261,391)	$ 416,364

(12) Fair Value Measurements

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

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

- Level 1 – Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 – Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.
- Level 3 – Unobservable inputs for which there is little, if any, market activity for the asset or liability being measured. These inputs reflect management's best estimates of the assumptions market participants would use in determining fair value. Our Level 3 measurements consist of instruments using standard pricing models and other valuation methods that utilize unobservable pricing inputs that are significant to the overall value.

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

Fair Values-Recurring

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

	Fair Value Measurements at December 31, 2017 Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of December 31, 2017
Trading securities held in the deferred compensation plans	$ 67,117	$ —	$ —	$ 67,117
Derivatives –swaps	—	3,910	—	3,910
–collars	—	3,039	85	3,124
–basis swaps	—	(9,025)	39	(8,986)
–freight swaps	—	276	—	276
–swaptions	—	—	6,534	6,534

	Fair Value Measurements at December 31, 2016 Using:			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Carrying Value as of December 31, 2016
Trading securities held in the deferred compensation plans	$ 61,717	$ —	$ —	$ 61,717
Derivatives –swaps	—	(207,979)	—	(207,979)
–collars	—	3,673	—	3,673
–puts	—	18,159	—	18,159
–calls	—	(1,041)	—	(1,041)
–basis swaps	—	11,106	—	11,106
–freight swaps	—	65	—	65

Our trading securities in Level 1 are exchange-traded and measured at fair value with a market approach using December 31, 2017 market values. Derivatives in Level 2 are measured at fair value with a market approach using third-party pricing services, which have been corroborated with data from active markets or broker quotes. As of December 31, 2017, a portion of our natural gas derivative instruments contain swaptions where the counterparty has the right, but not the obligation, to enter into a fixed price swap on a predetermined date. Derivatives in Level 3 are measured at fair value with a market approach using third-party pricing services, which have been corroborated with data from active markets or broker quotes. Subjectivity in the volatility factors utilized can cause a significant change in the fair value measurement of our swaptions. The following is a reconciliation of the beginning and ending balances for derivative instruments classified as Level 3 in the fair value hierarchy (in thousands):

	Year Ended December 31, 2017
Balance at the beginning of period	$ —
Total gains (losses):	
Included in earnings	6,658
Settlements received	—
Transfers in and/or out of Level 3	—
Balance at end of period	$ 6,658

Our trading securities held in the deferred compensation plan are accounted for using the mark-to-market accounting method and are included in other assets in the accompanying consolidated balance sheets. We elected to adopt the fair value option to simplify our accounting for the investments in our deferred compensation plan. Interest, dividends, and mark-to-market gains/losses are included in deferred compensation plan expense in the accompanying consolidated statements of operations. For the year ended December 31, 2017, interest and dividends were $4.1 million and mark-to-market was a gain of $4.2 million. For the year ended December 31, 2016, interest and dividends were $972,000 and mark-to-market was a gain of $3.1 million. For the year ended December 31, 2015, interest and dividends were $908,000 and mark-to-market was a loss of $5.9 million.

Fair Values-Non recurring

Due to declines in commodity prices and estimated reserves over the last three years, there were indications that the carrying values of certain natural gas and oil properties may be impaired and undiscounted future cash flows attributed to these assets indicated their carrying amounts were not expected to be recovered. Their fair value was measured using an income approach based upon internal estimates of future production levels, prices, drilling and operating costs and discount rates, which are Level 3 inputs. In some cases, we also considered the potential sale of certain of these properties. We recorded non-cash charges during the year ended 2017 of $63.7 million related to certain of our oil and gas properties in Oklahoma and the Texas Panhandle. We recorded non-cash charges during the year ended 2016 of $43.0 million related to certain of our natural gas and oil properties in Western Oklahoma. We recorded non-cash charges of $306.6 million during the year ended 2015 related to natural gas and oil properties in Northern Oklahoma, $195.6 million related to our shallow legacy oil and natural gas assets in Northwest Pennsylvania, $86.9 million related to our assets in the Texas Panhandle and $1.1 million related to our onshore Gulf Coast properties. The following table presents the value of these assets measured at fair value on a nonrecurring basis at the time impairment was recorded (in thousands):

	Year Ended December 31,					
	2017		2016		2015	
	Fair Value	Impairment	Fair Value	Impairment	Fair Value	Impairment
Natural gas and oil properties	$ 85,597	$ 63,679	$ 90,150	$ 43,040	$ 152,230	$ 590,174

Fair Values - Reported

The following table presents the carrying amounts and the fair values of our financial instruments as of December 31, 2017 and 2016 (in thousands):

	December 31, 2017		December 31, 2016	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Assets:				
Commodity swaps, options and basis swaps	$ 58,880	$ 58,880	$ 13,483	$ 13,483
Marketable securities [(a)]	67,117	67,117	61,717	61,717
(Liabilities):				
Commodity swaps, options and basis swaps	(54,022)	(54,022)	(189,500)	(189,500)
Bank credit facility [(b)]	(1,211,000)	(1,211,000)	(882,000)	(882,000)
5.75% senior notes due 2021 [(b)]	(475,952)	(493,872)	(475,952)	(496,180)
5.00% senior notes due 2022 [(b)]	(580,032)	(578,727)	(580,032)	(577,132)
5.875% senior notes due 2022 [(b)]	(329,244)	(339,200)	(329,244)	(343,648)
Other senior notes due 2022 [(b)]	(590)	(591)	(1,090)	(1,104)
5.00% senior notes due 2023 [(b)]	(741,531)	(735,614)	(741,531)	(735,043)
4.875% senior notes due 2025 [(b)]	(750,000)	(733,755)	(750,000)	(724,688)
5.75% senior subordinated notes due 2021 [(b)]	(22,214)	(22,192)	(22,214)	(22,325)
5.00% senior subordinated notes due 2022 [(b)]	(19,054)	(18,741)	(19,054)	(18,387)
5.00% senior subordinated notes due 2023 [(b)]	(7,712)	(7,614)	(7,712)	(7,645)
Deferred compensation plan [(c)]	(114,414)	(114,414)	(139,580)	(139,580)

(a) Marketable securities, which are held in our deferred compensation plans, are actively traded on major exchanges.

(b) The book value of our bank debt approximates fair value because of its floating rate structure. The fair value of our senior notes and our senior subordinated notes is based on end of period market quotes which are Level 2 inputs.

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

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

(13) Stock-Based Compensation Plans

Description of the Plans

The 2005 Equity Based Compensation Plan (the "2005 Plan") authorizes the compensation committee of the board of directors to grant, among other things, stock options, SARs, PSUs and restricted stock awards to employees. The 2005 Plan also allows us to provide equity compensation to our non-employee directors. The 2005 Plan was approved by stockholders in May 2005 and replaced our 1999 Stock Option Plan. The number of shares that may be issued under the 2005 Plan is equal to (i) 5.6 million shares plus (ii) the number of shares subject to the 1999 Stock Option Plan awards outstanding at May 18, 2005 that subsequently lapse or terminate without the underlying shares being issued plus (iii) subsequent shares approved by the stockholders. Shares issued as a result of awards granted are generally new common shares.

After the approval of the 2005 Plan, no new grants have been made from the 1999 Stock Option Plan. In addition, our 2004 Non-Employee Director Stock Option Plan expired at the end of 2014. Any awards previously granted under the 1999 Stock Option Plan or the 2004 Non-Employee Director Stock Option Plan continue to be exercisable in accordance with their original terms and conditions.

Total Stock-Based Compensation Expense

Stock-based compensation expense represents amortization of restricted stock and performance units. The following table details the amount of stock-based compensation that is allocated to functional expense categories for each of the years in the three-year period ended December 31, 2017 (in thousands):

	2017 (1)	2016	2015
Direct operating expense	$ 2,060	$ 2,302	$ 2,780
Brokered natural gas and marketing expense	1,437	1,725	2,132
Exploration expense	2,742	2,298	2,985
General and administrative expense	74,873	49,293	49,687
Termination costs	1,664	—	217
Total	$ 82,776	$ 55,618	$ 57,801

(1) Includes $30.8 million accelerated vesting of equity grants.

In fourth quarter 2017, the compensation committee approved a new post-retirement benefit plan (See *Other Post Retirement Benefits* below). Along with establishing the new health care benefit plan for certain officers that have met the required age and service requirements and with the intention of improving our management succession plan, those officers who qualify for the new post-retirement health care plan were fully vested in all equity grants. The one-time impact of the acceleration of these equity grants was $30.8 million in fourth quarter 2017.

Unlike the other forms of stock-based compensation expense mentioned above, the mark-to-market of the liability related to the vested restricted stock held in our deferred compensation plans is directly tied to the change in our stock price and not directly related to the functional expenses. Therefore, the liability related to the vested restricted stock held in our deferred compensation plans is not allocated to the functional categories and is reported as deferred compensation plan expense in the accompanying consolidated statements of operations.

In 2017, we recorded $5.3 million additional tax expense for the tax effect of excess financial accounting expense over the corporate income tax deduction for equity compensation vested during 2017. In 2016, we recorded $5.7 million additional tax expense for the tax effect of excess financial accounting expense over the corporate income tax deduction for equity compensation vested during 2016. In 2015, the tax deduction for stock-based compensation was less than the book stock-based compensation expense for equity compensation grants vested or exercised during the year. The tax effect of the 2015 deduction was recorded as a reduction to additional paid-in capital.

Stock-Based Awards

Restricted Stock Awards. We grant restricted stock units under our equity-based stock compensation plan. These restricted stock units, which we refer to as restricted stock Equity Awards, generally vest over a three year period, contingent on the recipient's continued employment. The grant date fair value of the Equity Awards is based on the fair market value of our common stock on the date of grant.

The compensation committee also grants restricted stock to certain employees and non-employee directors of the board of directors as part of their compensation. We also grant restricted stock to certain employees for retention purposes. Compensation expense is recognized over the balance of the vesting period, which is typically three years for employee grants and immediate vesting for non-employee directors. All restricted stock awards are issued at prevailing market prices at the time of the grant and the vesting is based upon an employee's continued employment with us. Prior to vesting, all restricted stock awards have the right to vote such stock (by the trustee) and receive dividends thereon. Upon grant of these restricted shares, which we refer to as restricted stock Liability Awards, the majority of these shares are generally placed in our deferred compensation plan and, upon vesting, withdrawals are allowed in either cash or in stock. These Liability Awards are classified as a liability and are remeasured at fair value each reporting period. This mark-to-market amount is reported in deferred compensation plan expense in the accompanying consolidated statements of operations. Historically, we have used authorized but unissued shares of stock when restricted stock is granted. However, we also utilize treasury shares when available.

Stock-Based Performance Units. We grant three types of performance share awards: two based on performance conditions measured against internal performance metrics (Production Growth Awards or "PG-PSUs" and Reserve Growth Awards or "RG-PSUs" and one based on market conditions measured based on Range's performance relative to a predetermined peer group (TSR Award or "TSR-PSUs").

At grant date, each unit represents the value of one share of our common stock. These units are settled in stock and the amount of the payout is based on (1) the vesting percentage, which can be from zero to 150% based on performance achieved and (2) the value of our common stock on the date vesting is determined by the Compensation Committee. Dividend equivalent may accrue during the performance period and would be paid in stock at the end of the performance period. The performance period is a three year period.

SARs. At December 31, 2017, there were 383,000 SARs outstanding.

Restricted Stock – Equity Awards

In 2017, we granted 888,000 restricted stock Equity Awards to employees which generally vest over a three-year period compared to 973,000 in 2016 and 588,000 in 2015. We recorded compensation expense for these awards of $23.4 million in the year ended December 31, 2017 compared to $22.8 million in 2016 and $23.8 million in 2015. As of December 31, 2017, there was $24.4 million of unrecognized compensation related to Equity Awards expected to be recognized over a weighted average period of 1.7 years. Restricted stock Equity Awards are not issued to employees until such time as they are vested and the employees do not have the option to receive cash.

Restricted Stock – Liability Awards

In 2017, we granted 543,000 shares of restricted stock Liability Awards as compensation to directors and employees at an average price of $25.91. This grant included 90,000 issued to non-employee directors which vest immediately and 453,000 to employees with vesting generally over a three year period. In 2016, we granted 540,000 shares of restricted stock Liability Awards as compensation to directors and employees at an average price of $35.92. This grant included 59,000 issued to non-employee directors which vest immediately and 481,000 to employees with vesting generally over a three-year period. In 2015, we granted 343,000 shares of restricted stock Liability Awards as compensation to directors and employees at an average price of $55.92. This grant included 48,000 issued to non-employee directors, which vest immediately and 295,000 to employees with vesting generally over a three-year period. We recorded compensation expense for these Liability Awards of $30.4 million in the year ended December 31, 2017 compared to $18.6 million in 2016 and $20.8 million in 2015. Accelerated vesting compensation expense of $15.4 million is included in the year ended December 31, 2017. As of December 31, 2017, there was $1.7 million of unrecognized compensation related to restricted stock Liability Awards expected to be recognized over a weighted average period of 1.6 years. The majority of all of these awards are held in our deferred compensation plan, are classified as a liability and are remeasured at fair value each reporting period. This mark-to-market amount is reported as deferred compensation expense in our consolidated statements of operations (see additional discussion below). The proceeds received from the sale of stock held in our deferred compensation plan were $4.5 million in 2017 compared to $13.1 million in 2016 and $8.3 million in 2015. The following is a summary of the status of our non-vested restricted stock outstanding at December 31, 2017:

	Restricted Stock Equity Awards		Restricted Stock Liability Awards	
	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2014	360,415	$ 79.60	304,504	$ 80.33
Granted	587,711	52.29	343,397	55.92
Vested	(480,253)	65.21	(330,870)	68.71
Forfeited	(31,109)	64.73	(8,294)	74.22
Outstanding at December 31, 2015	436,764	59.74	308,737	65.80
Granted	973,491	28.51	540,128	35.92
Vested	(525,617)	43.83	(374,328)	51.40
Forfeited	(118,667)	42.60	(49,519)	40.33
Outstanding at December 31, 2016	765,971	33.62	425,018	43.48
Granted	888,326	32.61	543,438	25.91
Vested	(698,563)	34.82	(908,912)	33.71
Forfeited	(122,676)	32.91	(4,342)	31.10
Outstanding at December 31, 2017	833,058	$ 31.64	55,202	$ 32.26

Stock-Based Performance Units

Production Growth and Reserve Growth Awards. The PG-PSUs and RG-PSUs vest at the end of the three-year performance period. The performance metrics for each year are set by the Compensation Committee no later than March 31 of such year. Based on our probability assessment at December 31, 2017, it is considered not probable that the criteria for the 2017 PG-PSUs will be met but it is considered probable that the criteria for the 2017 RG-PSUs will be met. If the performance metric for the applicable period is not met, then the portion is considered forfeited. The following is a summary of our non-vested PG/RG-PSUs awards outstanding at December 31, 2017:

	Number of Units	Weighted Average Grant Date Fair Value of Range Stock
Outstanding at December 31, 2016	—	—
Units granted [a]	122,921	$ 25.53
Outstanding at December 30, 2017	122,921	$ 25.53

[a] Amounts granted reflect the number of performance units granted; however, the actual payout of shares will be between zero and 150% depending on achievement of specifically identified performance targets.

We recorded PG/RG-PSUs compensation expense of $1.8 million in the year ended December 31, 2017, which includes $1.5 million accelerated vesting compensation expense.

TSR Awards. TSR-PSUs granted are earned, or not earned, based on the comparative performance of Range's common stock measured against a predetermined group of companies in the peer group over a three-year performance period. The fair value of the TSR-PSUs is estimated on the date of grant using a Monte Carlo simulation model which utilizes multiple input variables that determine the probability of satisfying the market condition stipulated in the award grant and calculates the fair value of the award. The fair value is recognized as stock-based compensation expense over the three year performance period. Expected volatilities utilized in the model were estimated using a combination of a historical period consistent with the remaining performance period of three years and option implied volatilities. The risk-free interest rate was based on the United States Treasury rate for a term commensurate with the life of the grant. The following assumptions were used to estimate the fair value of PSUs granted during the years ended December 31, 2017, 2016 and 2015:

	Year Ended December 31, 2017		
	2017	2016	2015
Risk-free interest rate	1.49%	0.94%	1.02%
Expected annual volatility	44%	49%	33%
Grant date fair value per unit	$ 26.26	$ 36.64	$ 56.78

The following is a summary of our non-vested TSR – PSUs award activities:

	Number of Units	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2014	226,418	$ 86.16
Granted [(a)]	276,204	56.78
Forfeited	(2,679)	82.60
Outstanding at December 31, 2015	499,943	69.95
Granted [(a)]	413,959	36.64
Forfeited	(42,603)	46.09
Outstanding at December 31, 2016	871,299	55.29
Granted [(a)]	358,519	26.26
Vested and issued [(b)]	(85,461)	86.23
Forfeited	(134,515)	85.24
Outstanding at December 31, 2017	1,009,842	$ 38.38

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

(b) Includes 85,461 TSR-PSU awards issued related to the 2014 performance period where the return on our common stock was the 67th percentile for the February 2014 grant and 56th percentile for the May 2014 grant. The remaining 2014 awards are considered to be forfeited.

We recorded TSR-PSU compensation expense of $24.8 million in the year ended December 31, 2017 compared to $12.4 million in the year ended December 31, 2016 and $8.7 million in the year ended December 31, 2015. Accelerated vesting compensation expense of $13.0 million is included in the year ended December 31, 2017. As of December 31, 2017, there was $1.2 million of unrecognized compensation related to PSU awards to be recognized over a weighted average period of 2.0 years.

SARs

Information with respect to our SARs activities is summarized below.

	Shares	Weighted Average Exercise Price
Outstanding at December 31, 2014	1,966,549	$ 59.80
Exercised	(427,598)	45.67
Expired/forfeited	(27,974)	63.10
Outstanding at December 31, 2015	1,510,977	63.73
Expired/forfeited	(507,377)	53.16
Outstanding at December 31, 2016	1,003,600	69.08
Expired/forfeited	(620,821)	62.29
Outstanding at December 31, 2017	382,779	$ 76.54

The following table shows information with respect to SARs outstanding and exercisable at December 31, 2017:

	Outstanding			Exercisable	
Range of Exercise Prices	Shares	Weighted Average Remaining Contractual Life (in years)	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
$ 70.00–$ 79.99	380,879	0.36	$ 76.51	380,879	$ 76.51
80.00–81.15	1,900	0.69	81.15	1,900	81.15
Total	382,779	0.36	$ 76.54	382,779	$ 76.54

The expected dividend yield is based on the current annual dividend at the time of grant. The expected life is based on the historical exercise activity. The expected volatility factors are based on a combination of both the historical volatilities of the stock and implied volatility of traded options on our common stock. The risk-free interest rate is based on the U.S. Treasury yield curve in effect at the time of grant for periods commensurate with the expected terms of the options.

The total intrinsic value (the difference in value between exercise and market price at the time of grant) of SARs exercised during the year ended December 31, 2015 was $5.4 million. There were no SARs exercised in 2017 or 2016. As of December 31, 2017, there was no aggregate intrinsic value for any of the awards exercisable or awards outstanding. The weighted average remaining contractual life of awards exercisable was less than one year. As of December 31, 2017, the number of fully vested awards and the awards expected to vest was 383,000 shares. The weighted average exercise price and weighted average remaining contractual life of these awards were $76.54 and 0.4 years. As of December 31, 2017, there was no unrecognized compensation cost related to the awards.

401(k) Plan

We maintain a 401(k) benefit plan that allows employees to contribute up to 75% of their salary (subject to Internal Revenue Service limitations) on a pretax basis. We match up to 6% of salary in cash and vesting of those contributions is immediate. In 2017, we contributed $5.1 million to the 401(k) Plan compared to $4.7 million in 2016 and $6.1 million in 2015. Employees have a variety of investment options in the 401(k) benefit plan.

Deferred Compensation Plan

Our deferred compensation plan gives directors, officers and key employees the ability to defer all or a portion of their salaries and bonuses and invest in Range common stock or make other investments at the individual's discretion. Range provides a partial matching contribution which vests over three years. The assets of the plans are held in a grantor trust, which we refer to as the Rabbi Trust, and are therefore available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. Our stock held in the Rabbi Trust is treated as a liability award as employees are allowed to take withdrawals from the Rabbi Trust either in cash or in Range stock. The liability for the vested portion of the stock held in the Rabbi Trust is reflected in the deferred compensation liability in the accompanying consolidated balance sheets and is adjusted to fair value each reporting period by a charge or credit to deferred compensation plan expense on our consolidated statements of operations. The assets of the Rabbi Trust, other than our common stock, are invested in marketable securities and reported at their market value in other assets in the accompanying consolidated balance sheets. The deferred compensation liability reflects the vested market value of the marketable securities and Range stock held in the Rabbi Trust. Changes in the market value of the marketable securities and changes in the fair value of the deferred compensation plan liability are charged or credited to deferred compensation plan expense each quarter. We recorded mark-to-market gain of $50.9 million in 2017 compared to a loss of $19.2 million in 2016 and a gain of $77.6 million in 2015. The Rabbi Trust held 2.9 million shares (2.8 million of vested shares) of Range stock at December 31, 2017 compared to 2.7 million (2.3 million of vested shares) at December 31, 2016.

Other Post Retirement Benefits

Effective fourth quarter 2017, we implemented a post-retirement benefit plan to assist in providing health care to officers who are active employees (including their spouses) and have met certain age and service requirements. These benefits are not funded in advance and are provided up to age 65 or at the date they become eligible for Medicare, subject to various cost-sharing features (in thousands).

	December 31, 2017
Accumulated benefit obligation	$ 1,769
Change in benefit obligations (recognized in comprehensive income – pretax)	
Beginning balance at December 31, 2016	$ —
Prior service cost	1,769
Total other comprehensive income (loss) at December 31, 2017	$ 1,769
Amounts recognized in the consolidated balance sheets:	
Noncurrent liability-accrued benefit cost	$ 1,769

The following summarizes the assumptions used to determine the benefit obligation at December 31, 2017.

	December 31, 2017
Weighted average assumptions used to determine benefit obligation:	
Discount rate	3.3%
Assumed weighted average healthcare cost trend rates:	
Initial healthcare trend rate	7.00%
Ultimate trend rate	5.00%
Year ultimate trend rate reached	2028

The expected future benefit payments under our post-retirement medical plan for the next ten years is $675,000 for the five year period 2018 through 2022 and $638,000 for the five year period 2023 through 2027. The estimated prior service cost that will be amortized from accumulated other comprehensive income into our statement of operations in 2018 is $369,000.

(14) Supplemental Cash Flow Information

	Year Ended December 31,		
	2017	2016	2015
		(in thousands)	
Net cash provided from operating activities included:			
Income taxes (refunded from) paid to taxing authorities	$ (1,024)	$ (102)	$ 100
Interest paid	179,431	159,875	168,826
Non-cash investing and financing activities included [(a)]:			
Asset retirement costs capitalized, net	$ 20,245	$ (24,064)	$ 22,184
Increase (decrease) in accrued capital expenditures	71,739	61,419	(225,455)

[(a)] For additional information on non-cash investing activities associated with the MRD Merger, see Note 3.

(15) Commitments and Contingencies

Litigation

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

Lease Commitments

We lease certain office space, office equipment, production facilities, compressors and transportation equipment under cancelable and non-cancelable leases. Rent expense under operating leases (including renewable monthly leases) totaled $19.1 million in 2017 compared to $14.0 million in 2016 and $15.9 million in 2015. Commitments related to these lease payments are not recorded in the accompanying consolidated balance sheets. Future minimum rental commitments under non-cancelable leases having remaining lease terms in excess of one year are as follows (in thousands):

	Operating Lease Obligations	Sublease Rental Receipts
2018	$ 18,498	$ 3,472
2019	17,803	3,472
2020	16,945	3,174
2021	14,249	2,578
2022	8,058	215
Thereafter	32,909	—
	$ 108,462	$ 12,911

Transportation, Gathering and Processing Contracts

We have entered into firm transportation and gathering contracts with various pipeline carriers for the future transportation and gathering of natural gas, NGLs and oil production from our properties in Pennsylvania and North Louisiana. Under these contracts, we are obligated to transport, process or gather minimum daily natural gas volumes, or pay for any deficiencies at a specified reservation fee rate. In most cases, our production committed to these pipelines is expected to exceed the minimum daily volumes provided in the contracts. As part of our purchase price allocation of liabilities that existed at the time of the MRD Merger, we have a remaining liability of $25.1 million for certain expected volume deficiency payments related to our properties in North Louisiana. As of December 31, 2017, future minimum transportation, processing and gathering fees under our commitments are as follows (in thousands):

	Transportation, Gathering and Processing Contracts [a]
2018	$ 805,161
2019	825,231
2020	767,090
2021	733,133
2022	691,968
Thereafter	4,689,133
	$ 8,511,716

[a] The amounts in this table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest which can vary based on volumes produced.

In addition to the amounts included in the above table, we have entered into an additional agreement which is contingent on certain pipeline modifications and/or construction. This agreement has a twenty year term and may begin in 2018. Based on this contract, we will have additional transportation obligations for natural gas volumes of 400,000 mcf per day until 2038.

Delivery Commitments

We have various volume delivery commitments that are primarily related to our Marcellus Shale and North Louisiana areas. We expect to be able to fulfill our contractual obligations from our own production; however, we may purchase third party volumes to satisfy our commitments or pay demand fees for commitment shortfalls, should they occur. As of December 31, 2017, our delivery commitments through 2031 were as follows:

Year Ending December 31,	Natural Gas (mmbtu per day)	Ethane and Propane (bbls per day)
2018	382,534	71,000
2019	364,356	55,932
2020	252,878	48,625
2021	116,189	48,000
2022	68,712	43,000
2023	—	35,000
2024—2028	—	35,000
2029—2031	—	20,000

In addition to the amounts included in the above table, we have contracted with a pipeline company through 2020 to deliver ethane production volumes from our Marcellus Shale wells. These agreements and related fees, which are contingent upon pipeline construction and/or modification, are for 13,000 bbls per day starting in 2018. In addition, we have agreements in place to deliver natural gas volumes from our Marcellus Shale wells, which are also contingent upon pipeline construction and/or modification, for 15,000 mcf per day starting in late 2018, increasing to 65,000 mcf per day in early 2019 and 180,000 mcf per day in late 2019.

Other

We also have lease acreage that is generally subject to lease expiration if initial wells are not drilled within a specified period, generally between three and five years. 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 and will allow additional acreage to expire in the future. To date, our expenditures to comply with environmental or safety regulations have not been a significant component of our cost structure and are not expected to be significant in the future. However, new regulations, enforcement policies, claims for damages or other events could result in significant future costs.

(16) Office Closing and Exit Costs

In first quarter 2015, we announced the closing of our Oklahoma City administrative and operational office in order to lower our general and administrative expenses, due in part to the impact of lower commodity prices on our operations. In fourth quarter 2014, we initially accrued an estimated $8.4 million of termination costs relating to the closure of this office as it had become probable of occurring. In early 2015, the plans to close the Oklahoma City office were finalized which resulted in additional accruals in 2015 for severance and other personnel costs of $275,000, additional accelerated vesting of stock-based compensation of $948,000 and $3.1 million of building lease costs. In the year ended December 31, 2015 additional accruals for severance of $11.4 million and a gain of $731,000 of accelerated vesting of stock-based compensation related to the sale of our Virginia and West Virginia properties which closed on December 30, 2015 and additional reductions in our work force due to the lower commodity price environment. There are no office closing or termination costs associated with the MRD Merger in 2016. As part of a continuing effort to reduce our general and administrative expenses due to the lower commodity price environment, additional accruals for severance of $2.2 million and accelerated vesting of stock-based compensation of $1.7 million were recorded in the year ended December 31, 2017. The following table details the accrued liability as of December 31, 2017 and December 31, 2016 (in thousands):

	2017	2016
Beginning balance	$ 2,460	$ 11,630
Accrued severance costs	2,176	(822)
Accrued building rent	(70)	303
Payments	(2,711)	(8,651)
Ending balance	$ 1,855	$ 2,460

The following summarizes our termination costs for three years ended December 31, 2017, 2016 and 2015 (in thousands):

	2017	2016	2015
Severance costs	$ 2,176	$ (822)	$ 11,706
Building lease	(70)	303	3,147
Stock-based compensation	1,664	—	217
Total termination costs	$ 3,770	$ (519)	$ 15,070

(17) Selected Quarterly Financial Data (Unaudited)

The following tables set forth unaudited financial information on a quarterly basis for each of the last two years. Third quarter 2017 includes impairment expense of $63.7 million related to oil and gas properties in Oklahoma and Texas. Fourth quarter 2017 deferred income tax benefit includes the impact of the Tax Cuts and Jobs Act of 2017 which was signed into law on December 22, 2017. First quarter 2016 includes impairment expense of $43.0 million related to oil and gas properties in Western Oklahoma. Second quarter, third quarter and fourth quarter 2016 include a total of $37.2 million of expenses related to the MRD Merger (in thousands, except per share data):

	2017				
	March	June	September	December	Total
Revenues and other income:					
Natural gas, NGLs and oil sales	$ 559,450	$ 506,137	$ 507,541	$ 603,159	$ 2,176,287
Derivative fair value income (loss)	165,557	111,195	(88,426)	25,024	213,350
Brokered natural gas, marketing and other	51,648	55,779	63,117	50,849	221,393
Total revenue and other income	776,655	673,111	482,232	679,032	2,611,030
Costs and expenses:					
Direct operating	28,023	31,420	36,888	37,921	134,252
Transportation, gathering, processing and compression	177,648	191,590	191,645	200,300	761,183
Production and ad valorem taxes	9,163	9,969	11,993	11,757	42,882
Brokered natural gas and marketing	53,550	55,857	59,773	51,131	220,311
Exploration	8,504	14,498	22,767	7,893	53,662
Abandonment and impairment of unproved properties	4,420	5,193	42,568	217,544	269,725
General and administrative	47,496	52,322	53,035	80,553	233,406
Termination costs	4,192	(96)	(47)	(279)	3,770
Deferred compensation plan	(13,169)	(14,466)	(9,203)	(14,077)	(50,915)
Interest	47,101	47,926	49,179	51,473	195,679
Depletion, depreciation and amortization	149,821	152,504	159,749	162,918	624,992
Impairment of proved properties and other	—	—	63,679	—	63,679
(Gain) loss on sale of assets	(22,600)	(807)	(102)	(207)	(23,716)
Total costs and expenses	494,149	545,910	681,924	806,927	2,528,910
Income (loss) before income taxes	282,506	127,201	(199,692)	(127,895)	82,120
Income tax expense (benefit):					
Current	—	—	—	17	17
Deferred	112,395	57,651	(71,992)	(349,097)	(251,043)
	112,395	57,651	(71,992)	(349,080)	(251,026)
Net income (loss)	$ 170,111	$ 69,550	$ (127,700)	$ 221,185	$ 333,146
Net income (loss) per common share:					
Basic	$ 0.69	$ 0.28	$ (0.52)	$ 0.89	$ 1.34
Diluted	$ 0.69	$ 0.28	$ (0.52)	$ 0.89	$ 1.34

	2016				
	March	June	September	December	Total
Revenues and other income:					
Natural gas, NGLs and oil sales	$ 209,487	$ 224,606	$ 304,477	$ 458,645	$ 1,197,215
Derivative fair value income (loss)	86,908	(162,798)	64,556	(250,057)	(261,391)
Brokered natural gas, marketing and other	35,018	39,989	44,174	44,934	164,115
Total revenue and other income	331,413	101,797	413,207	253,522	1,099,939
Costs and expenses:					
Direct operating	24,054	20,671	22,387	30,276	97,388
Transportation, gathering, processing and compression	125,263	136,844	138,764	164,338	565,209
Production and ad valorem taxes	5,887	6,049	6,717	6,790	25,443
Brokered natural gas and marketing	36,558	40,925	44,622	46,471	168,576
Exploration	4,913	6,785	6,943	13,684	32,325
Abandonment and impairment of unproved properties	10,628	7,059	6,082	6,307	30,076
General and administrative	40,657	46,064	41,024	57,027	184,772
MRD Merger expenses	—	2,621	33,791	813	37,225
Termination costs	162	5	136	(822)	(519)
Deferred compensation plan	16,056	25,746	(11,636)	(11,013)	19,153
Interest	37,739	37,758	45,967	46,749	168,213
Depletion, depreciation and amortization	120,561	122,390	131,489	149,662	524,102
Impairment of proved properties and other	43,040	—	—	—	43,040
Loss (gain) on sale of assets	1,643	3,304	2,597	(470)	7,074
Total costs and expenses	467,161	456,221	468,883	509,812	1,902,077
Loss before income taxes	(135,748)	(354,424)	(55,676)	(256,290)	(802,138)
Income tax expense (benefit):					
Current	—	—	—	98	98
Deferred	(41,976)	(129,488)	(13,705)	(95,679)	(280,848)
	(41,976)	(129,488)	(13,705)	(95,581)	(280,750)
Net loss	$ (93,772)	$ (224,936)	$ (41,971)	$ (160,709)	$ (521,388)
Net loss per common share:					
Basic	$ (0.56)	$ (1.35)	$ (0.23)	$ (0.66)	$ (2.75)
Diluted	$ (0.56)	$ (1.35)	$ (0.23)	$ (0.66)	$ (2.75)

(18) Supplemental Information on Natural Gas and Oil Exploration, Development and Production Activities (Unaudited)

Our natural gas and oil producing activities are conducted onshore within the continental United States and all of our proved reserves are located within the United States.

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

	December 31,		
	2017	2016	2015
		(in thousands)	
Natural gas and oil properties:			
Properties subject to depletion	$ 10,572,453	$ 9,462,350	$ 8,047,181
Unproved properties	2,644,000	2,923,803	949,155
Total	13,216,453	12,386,153	8,996,336
Accumulated depreciation, depletion and amortization	(3,649,716)	(3,129,816)	(2,635,031)
Net capitalized costs	$ 9,566,737	$ 9,256,337	$ 6,361,305

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

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

	December 31,		
	2017	2016	2015
		(in thousands)	
Acquisitions			
Acreage purchases	$ 62,075	$ 33,142	$ 73,025
Oil and gas properties	18,269	3,098,772	—
Asset retirement obligations and other	—	21,908	—
Development	1,177,526	497,795	708,268
Exploration:			
Drilling	2,030	37,680	87,505
Expense	50,920	30,027	18,421
Stock-based compensation expense	2,742	2,298	2,985
Gas gathering facilities:			
Development	15,097	3,595	13,337
Subtotal	1,328,659	3,725,217	903,541
Asset retirement obligations	20,245	(24,064)	22,184
Total costs incurred	$ 1,348,904	$ 3,701,153	$ 925,725

(a) Includes cost incurred whether capitalized or expensed.

Reserve Audit

All reserve information in this report is based on estimates prepared by our petroleum engineering staff. At year-end 2017, the following independent petroleum consultants conducted an audit of our reserves: Wright & Company, Inc. (Appalachia) and Netherland, Sewell & Associates, Inc. (North Louisiana). These engineers were selected for their geographic expertise and their historical experience in engineering certain properties. At December 31, 2017, our consultants collectively audited approximately 98% of our proved reserves. Copies of the summary reserve reports prepared by our independent petroleum consultants are included as exhibits to this Annual Report on Form 10-K. The technical professional at our independent petroleum consulting firms responsible for reviewing the reserve estimates presented herein meets the requirements regarding qualifications, independence, objectivity and confidentiality 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 reserves audit process. Throughout the year, our technical team meets periodically with representatives 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 reserves estimation process, our senior management reviews and approves any 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 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 lease-by-lease, field-by-field or area-by-area basis, some of our estimates may be greater and some may be less than the estimates of our 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, who reports directly to our Chairman, President and Chief Executive Officer. Mr. Alan Farquharson, 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.

Estimated Quantities of Proved Oil and Gas Reserves (Unaudited)

Reserves of natural gas, NGLs, crude oil and condensate are estimated by our petroleum engineering staff and are adjusted to reflect contractual arrangements and royalty rates in effect at the end of each year. Many assumptions and judgmental decisions are required to estimate reserves. Reported quantities are subject to future revisions, some of which may be substantial, as additional information becomes available from reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes, production taxes and other economic factors.

The SEC defines proved reserves as those volumes of natural gas, NGLs, crude oil and condensate that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those proved reserves which can be expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped reserves are volumes expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Proved undeveloped reserves can only be assigned to acreage for which improved recovery technology is contemplated when such techniques have been proven effective by actual tests in the area and in the same reservoir. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating each location is scheduled to be drilled within five years from the date it was booked as proved reserves, unless specific circumstances justify a longer time.

The reported value of proved reserves is not necessarily indicative of either fair market value or present value of future net cash flows because prices, costs and governmental policies do not remain static, appropriate discount rates may vary, and extensive judgment is required to estimate the timing of production. Other logical assumptions would likely have resulted in significantly different amounts.

The average realized prices used at December 31, 2017 to estimate reserve information were $45.73 per barrel of oil, $17.84 per barrel of NGLs and $2.60 per mcf for gas using a benchmark (NYMEX) of $51.19 per barrel and $2.98 per Mmbtu. The average realized prices used at December 31, 2016 to estimate reserve information were $37.41 per barrel of oil, $13.44 per barrel of NGLs and $2.07 per mcf for gas using a benchmark (NYMEX) of $42.68 per barrel and $2.48 per Mmbtu. The average realized prices used at December 31, 2015 to estimate reserve information were $35.07 per barrel of oil, $11.74 per barrel of NGLs and $2.07 per mcf for gas, using a benchmark (NYMEX) of $50.13 per barrel and $2.59 per Mmbtu.

	Natural Gas (Mmcf)	NGLs (Mbbls)	Crude Oil and Condensate (Mbbls)	Natural Gas Equivalents (Mmcfe) [(a)]
Proved developed and undeveloped reserves:				
Balance, December 31, 2014	6,922,836	515,907	48,658	10,310,229
Revisions	(340,286)	17,717	3,804	(211,163)
Extensions, discoveries and additions	1,017,956	36,308	4,924	1,265,348
Property sales	(960,122)	(441)	(109)	(963,423)
Production	(362,687)	(20,356)	(4,084)	(509,328)
Balance, December 31, 2015	6,277,697	549,135	53,193	9,891,663
Revisions	(7,441)	41,402	2,471	255,794
Extensions, discoveries and additions	1,193,154	26,991	6,506	1,394,134
Purchases	943,544	40,724	11,986	1,259,806
Property sales	(160,727)	(360)	(295)	(164,655)
Production	(375,811)	(27,826)	(3,609)	(564,420)
Balance, December 31, 2016	7,870,416	630,066	70,252	12,072,322
Revisions	70,222	83,338	(10,555)	506,919
Extensions, discoveries and additions	2,866,103	87,572	15,997	3,487,519
Purchases	7,738	330	66	10,116
Property sales	(60,278)	(2,356)	(1,121)	(81,133)
Production	(490,552)	(35,686)	(4,785)	(733,382)
Balance, December 31, 2017	10,263,649	763,264	69,854	15,262,361
Proved developed reserves:				
December 31, 2015	3,376,165	309,306	31,679	5,422,075
December 31, 2016	4,352,141	363,852	39,110	6,769,908
December 31, 2017	5,437,674	448,258	36,808	8,348,074
Proved undeveloped reserves:				
December 31, 2015	2,901,533	239,828	21,514	4,469,588
December 31, 2016	3,518,275	266,214	31,143	5,302,414
December 31, 2017	4,825,975	315,006	33,046	6,914,287

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

During 2017, we added approximately 3.5 Tcfe of proved reserves from drilling activities and evaluation of proved areas primarily in the Marcellus Shale. Approximately 82% of the 2017 reserve additions are attributable to natural gas. Included in 2017 proved reserves is a total of 360.6 Mmbbls of ethane reserves (1,596 Bcfe) in the Marcellus Shale. Revisions of previous estimates of 507 Bcfe includes positive performance revisions of 532 Bcfe, improved recoveries of 597 Bcfe, positive pricing revisions of 46 Bcfe partially offset by 668 Bcfe reclassified to unproved for previously planned wells not to be drilled within the original five-year development horizon. Purchases of reserves in 2017 reflects reserves added in North Louisiana.

During 2016, we added approximately 1.4 Tcfe of proved reserves from drilling activities and evaluation of proved areas primarily in the Marcellus Shale. Approximately 86% of the 2016 reserve additions are attributable to natural gas. Included in 2016 proved reserves is a total of 308.9 Mmbbls of ethane reserves (1,367 Bcfe) in the Marcellus Shale. Revisions of previous estimates of 256 Bcfe includes positive performance revisions of 154 Bcfe and improved recoveries of 393 Bcfe primarily from our Marcellus Shale natural gas properties partially offset by negative price revisions and 269 Bcfe reclassified to unproved for previously planned wells not to be drilled within the original five-year development horizon. Purchases of reserves in 2016 reflect reserves added in North Louisiana, primarily from the MRD Merger.

During 2015, we added approximately 1.3 Tcfe of proved reserves from drilling activities and evaluation of proved areas primarily in the Marcellus Shale. Approximately 80% of the 2015 reserve additions are attributable to natural gas. Included in 2015 proved reserves is a total of 292.8 Mmbbls of ethane reserves (1,296 Bcfe) in the Marcellus Shale. Revisions of previous estimates of a negative 211 Bcfe includes positive performance revisions and improved recoveries of 781.0 Bcf primarily from our Marcellus

Shale natural gas properties more than offset by negative price revisions and 1.2 Tcfe reclassified to unproved because of lower future capital spending in response to lower commodity prices.

The following details the changes in proved undeveloped reserves for 2017 (Mmcfe):

Beginning proved undeveloped reserves at December 31, 2016	5,302,414
Undeveloped reserves transferred to developed	(1,861,994)
Revisions [(a)]	308,929
Purchases/(sales)	(8,907)
Extension and discoveries	3,173,845
Ending proved undeveloped reserves at December 31, 2017	6,914,287

[(a)] Includes 668 Bcfe of proved undeveloped reserves dropped due to the five year rule which can be included in our future proved reserves as these locations are added back to our five-year development plan.

Approximately $920 million was spent during 2017 related to undeveloped reserves that were transferred to developed reserves. Estimated future development costs of proved undeveloped reserves are projected to be approximately $717 million in 2018, $707 million in 2019 and $567 million in 2020. As of December 31, 2017, we have 64 Bcfe of reserves (less than 1% of total proved undeveloped reserves) that have been reported for more than five years from their original date of booking, all of which are in the process of being drilled. All of our recorded proved undeveloped drilling locations are scheduled to be drilled within five years of initial disclosure. All proved undeveloped drilling locations are scheduled to be drilled prior to the end of 2022.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Unaudited)

The following summarizes the policies we used in the preparation of the accompanying natural gas, NGLs, crude oil and condensate reserve disclosures, standardized measures of discounted future net cash flows from proved natural gas, NGLs and oil reserves and the reconciliations of standardized measures from year to year. The information disclosed is an attempt to present the information in a manner comparable with industry peers.

The information is based on estimates of proved reserves attributable to our interest in natural gas and oil properties as of December 31 of the years presented. These estimates were prepared by our petroleum engineering staff. Proved reserves are estimated quantities of natural gas, NGLs, crude oil and condensate, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

1. Estimates are made of quantities of proved reserves and future amounts expected to be produced based on current year-end economic conditions.
2. For the years ended 2017, 2016 and 2015, estimated future cash inflows are calculated by applying a twelve-month average price of natural gas, NGLs and oil relating to our proved reserves to the quantities of those reserves produced in each future year.
3. 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 year-end economic conditions. Future income tax expenses are based on current year-end statutory tax rates giving effect to the remaining tax basis in the natural gas, NGLs and oil properties, other deductions, credits and allowances relating to our proved natural gas and oil reserves.
4. The resulting future net cash flows are discounted to present value by applying a discount rate of 10%.

The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair value of our natural gas, NGLs and oil reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

The standardized measure of discounted future net cash flows relating to proved natural gas, NGLs, crude oil and condensate reserves is as follows and excludes cash flows associated with derivatives outstanding at each of the respective reporting dates. Future cash inflows are net of third party transportation, gathering and compression expense.

	As of December 31, 2017	As of December 31, 2016
	(in thousands)	
Future cash inflows	$ 43,500,054	$ 27,413,864
Future costs:		
Production	(18,958,695)	(14,465,059)
Development [(a)]	(3,072,688)	(2,647,801)
Future net cash flows before income taxes	21,468,671	10,301,004
Future income tax expense	(3,989,459)	(1,946,259)
Total future net cash flows before 10% discount	17,479,212	8,354,745
10% annual discount	(10,313,998)	(4,902,816)
Standardized measure of discounted future net cash flows	$ 7,165,214	$ 3,451,929

[(a)] 2017 includes $430.6 million of undiscounted future asset retirement costs estimated as of December 31, 2017, using current estimates of future abandonment costs.

The following table summarizes changes in the standardized measure of discounted future net cash flows.

	December 31, 2017	December 31, 2016	December 31, 2015
		(in thousands)	
Revisions of previous estimates:			
Changes in prices and production costs	$ 2,615,825	$ (212,867)	$ (7,231,629)
Revisions in quantities	445,667	96,615	(868,886)
Changes in future development and abandonment costs	(497,400)	(314,864)	359,540
Net change in income taxes	(706,531)	27,842	2,173,904
Accretion of discount	372,743	302,920	1,007,027
Purchases of reserves in place	6,173	488,959	—
Additions to proved reserves from extensions, discoveries and improved recovery	2,128,135	541,095	486,478
Natural gas, NGLs and oil sales, net of production costs	(1,237,970)	(509,174)	(522,682)
Development costs incurred during the period	885,803	435,928	1,033,539
Sales of reserves in place	(32,946)	(65,538)	(1,050,237)
Timing and other	(266,214)	(64,850)	(254,218)
Net change for the year	3,713,285	726,066	(4,867,164)
Beginning of year	3,451,929	2,725,863	7,593,027
End of year	$ 7,165,214	$ 3,451,929	$ 2,725,863

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures. As required by Rule 13a-15(b) under the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Form 10-K. Our disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2017 at the reasonable assurance level.

Changes in Internal Controls over Financial Reporting. There have been no changes in our system of internal control over financial reporting (such as term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the quarter ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting. See "Management's Report on Internal Control over Financial Reporting" and "Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting" which appear on pages F-2 and F-3, respectively, under Item 8. Financial Statements and Supplementary Data.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The executive officers and directors are listed below with a description of their experience and certain other information. Each director was elected for a one-year term at the 2017 annual stockholders' meeting. Executive officers are appointed by our board of directors.

	Age	Director/ Officer Since	Position
Brenda A. Cline	57	2015	Director
Anthony V. Dub	68	1995	Director
Allen Finkelson	71	1994	Director
James M. Funk	68	2008	Lead Independent Director
Christopher A. Helms	63	2014	Director
Robert A. Innamorati	70	2016	Director
Mary Ralph Lowe	71	2013	Director
Greg G. Maxwell	61	2015	Director
Kevin S. McCarthy	58	2005	Director
Steffen E. Palko	67	2016	Director
Jeffrey L. Ventura	60	2003	Chairman, President and Chief Executive Officer
Roger S. Manny	60	2003	Executive Vice President – Chief Financial Officer
Ray N. Walker, Jr.	60	2010	Executive Vice President – Chief Operating Officer
Dori A. Ginn	60	2009	Senior Vice President – Controller and Principal Accounting Officer
David P. Poole	55	2008	Senior Vice President – General Counsel and Corporate Secretary

Brenda A. Cline became a director in 2015. Ms. Cline currently serves as chief financial officer, treasurer, and secretary of the Kimbell Art Foundation, a private operating foundation that owns and operates the Kimbell Art Museum, Fort Worth, Texas. Ms. Cline has also served as an independent trustee of American Beacon Funds since 2004 and currently serves as the vice chair and the chair of the audit and compliance committee. In 2017, she was appointed a director of the Cushing Closed-End Funds. She is a director of Tyler Technologies, Inc., serving on the nominating and governance committee and as the chair of the audit committee. From 1993 until 2013, Ms. Cline served as a contract author for Thomson Reuters, Fort Worth, Texas. From 1982 to 1993, Ms. Cline held various positions with Ernst & Young LLP in its audit practice. Ms. Cline also serves on the boards of certain non-profit entities, including on the board of trustees of Texas Christian University and the Pension Fund of the Christian Church. Ms. Cline is a certified public accountant. She received her Bachelor of Business Administration, Accounting degree, summa cum laude, from Texas Christian University.

Anthony V. Dub became a director in 1995. Mr. Dub is Chairman of Indigo Capital, LLC, a financial advisory firm based in New York. Before forming Indigo Capital in 1997, he served as an officer of Credit Suisse First Boston ("CSFB"). Mr. Dub joined CSFB in 1971 and was named a managing director in 1981. Mr. Dub led a number of departments during his 26 year career at CSFB including the investment banking department. After leaving CSFB, Mr. Dub became vice chairman and a director of Capital IQ, Inc. until its sale to Standard & Poor's in 2004. Capital IQ is a leader in helping organizations capitalize on synergistic integration of market intelligence, institutional knowledge and relationships. Mr. Dub received a Bachelor of Arts degree, magna cum laude, from Princeton University.

Allen Finkelson became a director in 1994. Mr. Finkelson was a partner at Cravath, Swaine & Moore LLP from 1977 to 2011, with the exception of the period 1983 through 1985, when he was a managing director of Lehman Brothers Kuhn Loeb Incorporated. Mr. Finkelson joined Cravath, Swaine & Moore LLP in 1971. Mr. Finkelson earned a Bachelor of Arts from St. Lawrence University and a J.D. from Columbia University School of Law.

James M. Funk became a director in December 2008 and was elected as lead independent director in 2015. Mr. Funk is an independent consultant and oil and gas producer with over 30 years of experience in the energy industry. Mr. Funk served as senior vice president of Equitable Resources and president of Equitable Production Co. from June 2000 until December 2003. Previously, Mr. Funk was employed by Shell Oil Company for 23 years in senior management and technical positions. Mr. Funk has previously served on the boards of Westport Resources (2000 to 2004) and Matador Resources Company (2003 to 2008). Mr. Funk currently serves as a director of Superior Energy Services, Inc., a public oil field services company headquartered in New Orleans, Louisiana. Mr. Funk received a B.A. degree in Geology from Wittenberg University, a M.S. in Geology from the University of Connecticut and a PhD in Geology from the University of Kansas. Mr. Funk is a certified petroleum geologist.

Christopher A. Helms became a director in July 2014. Mr. Helms has over 40 years of experience in the energy industry, principally in the midstream sector. Mr. Helms is the president and chief executive officer of US Shale Energy Advisors LLC and subsidiaries that include Rocky Mountain Crude Oil LLC which own and operate energy midstream and logistics assets. Prior to his retirement in 2012, Mr. Helms was executive vice president and group chief executive officer of NiSource Inc. From 2005 to 2011 he served as chief executive officer and executive director of NiSource Gas Transmission and Storage. Mr. Helms serves as a director of MPLX GP LLC. He has previously served on the boards of Questar Corporation, Coskata, Inc., Millennium Pipeline Company LLC and Centennial Pipeline Company LLC and as a director of the Marcellus Shale Coalition, the Commonwealth of Pennsylvania Marcellus Shale Advisory Commission, as vice chair of the Interstate Natural Gas Association of America and chair of the Southern Gas Association. Mr. Helms received a Bachelor of Arts from Southern Illinois University at Edwardsville and a Juris Doctor from Tulane University School of Law.

Robert A. Innamorati became a director in 2016. Mr. Innamorati has served as President of Robert A. Innamorati & Co., a private investment and advisory firm, since 1995. Mr. Innamorati served as a member of the board of directors of Memorial Production Partners GP LLC from August 2012 to December 2014 and Memorial Resource Development Corp. from June 2014 to September 2016, where he served as chairman of the audit committee. He also served as president of a private investment company with net assets of $1.5 billion from 2007 until 2012. Mr. Innamorati was a member of ownership and served on the board of The Texas Rangers Baseball Club (MLB) until February 2013, where he served as chairman of the compensation committee and was a member of the finance committee. From 1979 until 1995, Mr. Innamorati held senior positions in investment banking. He also served as a special agent with the United States Secret Service and received an honorable discharge from the United Marine Corps Reserves. Mr. Innamorati has also served as a board member for several private companies. Mr. Innamorati earned a Bachelor of Science degree in finance and a MBA degree from the University of Virginia.

Mary Ralph Lowe became a director in 2013. Ms. Lowe has been president and chief executive officer of Maralo, LLC, (formerly Maralo, Inc.), an independent oil and gas royalty company, and ranching operation, since 1973, and a member of its board of directors since 1975. Ms. Lowe also serves on the board of trustees of Texas Christian University, the board of the Performing Arts Center of Fort Worth, the board of the National Cowgirl Museum and Hall of Fame, the board of The Modern Art Museum of Fort Worth and is a member of the World President's Organization in Fort Worth and Houston, Texas. Ms. Lowe previously served on the board of Apache Corporation, an oil and gas exploration company.

Greg G. Maxwell became a director in September 2015. Mr. Maxwell served as executive vice president, finance, and chief financial officer for Phillips 66, a diversified energy manufacturing and logistics company until his retirement on December 31, 2015. Mr. Maxwell has over 37 years of experience in various financial roles within the petrochemical and oil and gas industries. Mr. Maxwell served as senior vice president, chief financial officer and controller for Chevron Phillips Chemical Company from 2003 until joining Phillips 66 in 2012. He joined Phillips Petroleum Company in 1978 and held various positions within the comptrollers group including the corporate planning and development group, the corporate treasury department and downstream business units. Mr. Maxwell also served as vice president, chief financial officer and a member of the board of directors of Phillips 66 Partners and on the board of directors of DCP Midstream LLC and Chevron Phillips Chemical Company until his retirement in 2015. In 2017, he joined the board of Jeld-Wen Holding, Inc. He is a certified public accountant and a certified internal auditor. He earned a Bachelor of Accountancy degree from New Mexico State University in 1978.

Kevin S. McCarthy became a director in 2005. Mr. McCarthy is Co-founder and Managing Partner for Kayne Anderson Fund Advisors ("Kayne Anderson"). Mr. McCarthy is responsible for MLP and private equity investments and serves as Chairman, Chief Executive Officer and President of four publicly traded closed end funds for which Kayne Anderson serves as the investment manager and as Chairman of a special purposed acquisition company ("SPAC") sponsored by Kayne Anderson. Mr. McCarthy joined Kayne Anderson Capital Advisors as a senior managing director in 2004 from UBS Securities LLC where he was global head of energy investment banking. In this role, he had senior responsibility for all of UBS' energy investment banking activities, including direct responsibilities for securities underwriting and mergers and acquisitions in the energy industry. From 1995 to 2000, Mr. McCarthy led the energy investment banking activities of Dean Witter Reynolds and then PaineWebber Incorporated. He began his investment banking career in 1984. He previously served on the board of ONEOK, Inc., Emerge Energy Services, L.P. and K-Sea Transportation Partners, L.P. He earned a Bachelor of Arts in Economics and Geology from Amherst College and an MBA in Finance from the University of Pennsylvania's Wharton School.

Steffen E. Palko, Ed.D., became a director in 2016. Mr. Palko was co-founder of XTO Energy Inc., serving as President and Vice-Chairman from 1986 to 2005, which became the largest independent natural gas producer in the United States in 2009. Previously, Mr. Palko served as a trustee for the Fort Worth ISD school board, and assumed numerous educational leadership roles at the state and national levels, including chair of the National Assessment of Vocational Education for the United States Department of Education and Commissioner for the U.S. Department of Labor SCANS committee. Mr. Palko earned his Doctorate in Educational Leadership from Texas Christian University, where he currently serves as an Associate Professor. He earned his Bachelor of Science in Electrical Engineering from the University of Texas at El Paso.

Jeffrey L. Ventura, chairman, president and chief executive officer, joined Range in 2003 as chief operating officer and became a director in 2005. Mr. Ventura was named President effective May 2008, Chief Executive Officer effective January 2012 and named chairman of the board on January 1, 2015. Previously, Mr. Ventura served as president and chief operating officer of Matador Petroleum Corporation which he joined in 1997. Prior to his service at Matador, Mr. Ventura spent eight years at Maxus Energy Corporation where he managed various engineering, exploration and development operations and was responsible for coordination of engineering technology. Previously, Mr. Ventura was with Tenneco Oil Exploration and Production, where he held various engineering and operating positions. Mr. Ventura holds a Bachelor of Science degree in Petroleum and Natural Gas Engineering from the Pennsylvania State University. Mr. Ventura is a member of the Society of Petroleum Engineers, American Association of Petroleum Geologists and the Texas Society of Professional Engineers.

Roger S. Manny, executive vice president – chief financial officer. Mr. Manny joined Range in 2003. Previously, Mr. Manny served as executive vice president and chief financial officer of Matador Petroleum Corporation from 1998 until joining Range. Before 1998, Mr. Manny spent 18 years at Bank of America and its predecessors where he served as senior vice president in the energy group. Mr. Manny holds a Bachelor of Business Administration degree from the University of Houston and a Masters of Business Administration from Houston Baptist University.

Ray N. Walker, Jr., executive vice president – chief operating officer, joined Range in 2006 and was elected to his current position in January 2014. Previously, Mr. Walker served as senior vice president – chief operating officer, senior vice president-environment, safety and regulatory and senior vice president-Marcellus Shale where he led the development of the Range's Marcellus Shale division. Mr. Walker is a petroleum engineer with more than 35 years of oil and gas operations and management experience having previously been employed by Halliburton in various technical and management roles, Union Pacific Resources and several private companies in which Mr. Walker served as an officer. Mr. Walker has a Bachelor of Science degree in Agricultural Engineering from Texas A&M University.

Dori A. Ginn, senior vice president – controller and principal accounting officer, joined Range in 2001 and was previously vice president, controller and principal accounting officer. Ms. Ginn has held the positions of financial reporting manager, vice president and controller before being elected to principal accounting officer in September 2009. Prior to joining Range, she held various accounting positions with Doskocil Manufacturing Company and Texas Oil and Gas Corporation. Ms. Ginn received a Bachelor of Business Administration in Accounting from the University of Texas at Arlington. She is a certified public accountant.

David P. Poole, senior vice president – general counsel and corporate secretary, joined Range in June 2008. Mr. Poole has over 28 years of legal experience. From May 2004 until March 2008 he was with TXU Corp., serving last as executive vice president – legal, and general Counsel. Prior to joining TXU, Mr. Poole spent 16 years with Hunton & Williams LLP and its predecessor, where he was a partner and last served as the managing partner of the Dallas office. Mr. Poole graduated from Texas Tech University with a B.S. in Petroleum Engineering and received a J.D. magna cum laude from Texas Tech University School of Law.

Section 16(a) Beneficial Ownership Reporting Compliance

See the material appearing under the heading "Section 16(a) Beneficial Ownership Reporting Compliance" in the Range Proxy Statement for the 2018 Annual Meeting of Stockholders which is incorporated herein by reference. Section 16(a) of the Exchange Act requires our directors, officers (including a person performing a principal policy-making function) and persons who own more than 10% of a registered class of our equity securities to file with the SEC initial reports of ownership and reports of changes in ownership of our common stock and other equity securities. Directors, officers and 10% holders are required by SEC regulations to send us copies of all of the Section 16(a) reports they file. Based solely on a review of the copies of the forms sent to us and the representations made by the reporting persons to us, we believe that, during the fiscal year ended December 31, 2017, our directors, officers and 10% holders complied with all filing requirements under Section 16(a) of the Exchange Act.

Code of Ethics

Code of Ethics. We have adopted a Code of Ethics that applies to our principal executive officer, principal financial officer, principal accounting officer, or persons performing similar functions (as well as our directors and all other employees). A copy is available on our website, www.rangeresources.com and a copy in print will be provided to any person without charge, upon request. Such requests should be directed to the Corporate Secretary, 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102 or by calling (817) 870-2601. We intend to disclose any amendments to or waivers of the Code of Ethics on behalf of our President and Chief Executive Officer, Chief Financial Officer, Controller and persons performing similar functions on our website, under the Corporate Governance caption, promptly following the date of such amendment or waiver.

Identifying and Evaluating Nominees for Directors

See "Identifying and Evaluating Nominees for Directors, including Diversity Considerations" in the Range Proxy Statement for the 2018 Annual Meeting of Stockholders, which is incorporated herein by reference.

Audit Committee

See the material under the heading "Audit Committee" in the Range Proxy Statement for the 2018 Annual Meeting of Stockholders, which is incorporated herein by reference.

NYSE 303A Certification

The President and Chief Executive Officer of Range Resources Corporation made an unqualified certification to the NYSE with respect to the Company's compliance with the NYSE Corporate Governance listing standards on May 22, 2017.

ITEM 11. EXECUTIVE COMPENSATION

Information required by this item is incorporated by reference to such information as set forth in the Range Proxy Statement for the 2018 Annual Meeting of Stockholders.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by this item is incorporated by reference to such information as set forth in the Range Proxy Statement for the 2018 Annual Meeting of Stockholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information required by this item is incorporated by reference to such information as set forth in the Range Proxy Statement for the 2018 Annual Meeting of Stockholders.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required by this item is incorporated by reference to such information as set forth in the Range Proxy Statement for the 2018 Annual Meeting of Stockholders.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) 1. and 2. Financial Statements and Financial Statement Schedules.

The financial statements and financial statement schedules listed in the Index to Financial Statements in Item 8 are filed as part of this Form 10-K:

3. Exhibits

The exhibits listed in the accompanying Exhibits Index are filed as part of this Form 10-K.

Exhibit Number	Exhibit Description
2.1	Agreement and Plan of Merger by and among Range Resources Corporation, Medina Merger Sub, Inc. and Memorial Resource Development Corp., dated as of May 15, 2016 (incorporated by reference to Exhibit 2.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 19, 2016)
3.1	Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on May 5, 2004) as amended by the Certificate of First Amendment to Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on July 28, 2005 and the Certificate of Second Amendment to the Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on July 24, 2008)
3.2	Amended and Restated By-laws of Range (incorporated by reference to Exhibit 3.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 19, 2016)
4.1	Form of 5.75% Senior Subordinated Notes due 2021 (incorporated by reference to Exhibit A to Exhibit 4.2 on Form 8-K (File No. 001-12209) as filed with the SEC on May 25, 2011)
4.2	Indenture dated May 25, 2011 by and among Range, as issuer, the Subsidiary Guarantors (as defined therein), as guarantors and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.1 on our Form 8-K (File No. 001-12209) as filed with the SEC on May 25, 2011)
4.3	Form of 5.00% Senior Subordinated Notes due 2022 (incorporated by reference to Exhibit A to Exhibit 4.1 on our Form 8-K (File No. 001-12209) as filed with the SEC on March 9, 2012)
4.4	Indenture dated March 9, 2012 by and among Range, as issuer, the Subsidiary Guarantors (as defined therein), as guarantors and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.1 on our Form 8-K (File No. 001-12209) as filed with the SEC on March 9, 2012)
4.5	Form of 5.00% Senior Subordinated Notes due 2023 (incorporated by reference to Exhibit A to Exhibit 4.1 on our Form 8-K (File No. 001-12209) as filed with the SEC on March 19, 2013)
4.6	Indenture dated March 18, 2013 among Range Resources Corporation, as issuer, the Subsidiary Guarantors (as defined therein) as guarantors and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 on our Form 8-K (File No. 001-12209) as filed with the SEC on March 19, 2013)
4.7	Form of 4.875% Senior Notes due 2025 (incorporated by reference to Exhibit A to Exhibit 4.1 on Form 8-K (File No. 001-12009) as filed with the SEC on May 14, 2015)
4.8	Indenture dated May 14, 2015 among Range Resources Corporation, as issuer, the Initial Guarantors (as defined therein) and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 on our Form 8-K (File No. 001-12209) as filed with the SEC on May 14, 2015)
4.9	Second Supplemental Indenture, by and among Range Resources Corporation, the guarantors named therein and The Bank of New York Mellon Trust Company, N.A., dated as of August 23, 2016 (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K (File No. 001-12209) as filed with the SEC on August 25, 2016)
4.10	Second Supplemental Indenture, by and among Range Resources Corporation, the guarantors named therein and The

Exhibit Number	Exhibit Description
	Bank of New York Mellon Trust Company, N.A., dated as of August 23, 2016 (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K (File No. 001-12209) as filed with the SEC on August 25, 2016)
4.11	First Supplemental Indenture, by and among Range Resources Corporation, the guarantors named therein and U.S. Bank National Association, dated as of August 23, 2016 (incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K (File No. 001-12209) as filed with the SEC on August 25, 2016)
4.12	Form of 5.75% Senior Notes due 2021 (incorporated by reference to Exhibit 4.1 on our Form 8-K (File No. 001-12209) as filed with the SEC on September 19, 2016)
4.13	Indenture dated September 16, 2016 among Range Resources Corporation, as issuer, the Subsidiary Guarantors (as defined therein) as guarantors and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 on our Form 8-K (File No. 001-12209) as filed with the SEC on September 19, 2016)
4.14	Form of 5.00% Senior Notes due 2022 (incorporated by reference to Exhibit 4.2 our Form 8-K (File No. 001-12209) as filed with the SEC on September 19, 2016)
4.15	Indenture dated September 16, 2016 among Range Resources Corporation, as issuer the Subsidiary Guarantors (as defined therein) as guarantors and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 on our Form 8-K (File No. 001-12209) as filed with the SEC on September 19, 2016)
4.16	Form of 5.00% Senior Notes due 2023 (incorporated by reference to Exhibit 4.3 on our Form 8-K (File No. 001-12209) as filed with the SEC on September 19, 2016)
4.17	Indenture dated September 16, 2016 among Range Resources Corporation, as issuer, the Subsidiary Guarantors (as defined therein) as guarantors and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 on our Form 8-K (File No. 001-12209) as filed with the SEC on September 19, 2016)
4.18	Form of 5.875% Senior Notes due 2022 (incorporated by reference to Exhibit 4.4 on our Form 8-K (File No. 001-12209) as filed with the SEC on September 19, 2016)
4.19	Indenture dated September 16, 2016 among Range Resources Corporation, as issuer, the Subsidiary Guarantors (as defined therein) as guarantors and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.4 on our Form 8-K (File No. 001-12209) as filed with the SEC on September 19, 2016)
10.01	Fifth Amended and Restated Credit Agreement, dated as of October 16, 2014 among Range (as borrowers) and JPMorgan Chase Bank, N.A. and the institutions named (therein) as lenders, JPMorgan Chase as Administrative Agent (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on October 20, 2014)
10.02	First Amendment to the Fifth Amended and Restated Credit Agreement among Range Resources Corporation (as borrower) and the institutions named therein as lenders. JPMorgan Chase Bank, N.A. as Administrative Agent (incorporated by reference to Exhibit 99.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on April 1, 2015)
10.03	Second Amendment to the Fifth Amended and Restated Credit Agreement among Range Resources Corporation (as borrower) and the institutions named therein as lenders. JPMorgan Chase Bank, N.A. as Administrative Agent (incorporated by reference to Exhibit 10.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on April 28, 2016)
10.04	Amended and Restated Range Resources Corporation 2004 Deferred Compensation Plan for Directors and Select Employees effective December 31, 2008 (incorporated by reference to Exhibit 10.2 to our Form 8-K (File No. 001-12209) as filed with the SEC on December 5, 2008)
10.05	Range Resources Corporation Amended and Restated 2005 Equity Based Compensation Plan (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on June 4, 2009)
10.06	First Amendment to the Range Resources Corporation Amended and Restated 2005 Equity Based Compensation Plan (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 20, 2010)
10.07	Second Amendment to the Range Resources Corporation Amended and Restated 2005 Equity Based Compensation Plan (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 19, 2011)
10.08	Range Resources Corporation 401(k) Plan (incorporated by reference to Exhibit 10.14 to our Form S-4 (File No. 333-

Exhibit Number	Exhibit Description
	108516) as filed with the SEC on September 4, 2003)
10.09	Amended and Restated Range Resources Corporation Executive Change in Control Severance Benefit Plan effective December 31, 2008 (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on December 5, 2008)
10.10	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.6 to our Form 8-K (File No. 001-12209) as filed with the SEC on February 17, 2009)
10.11	Voting and Support Agreement, by and among MRD Holdco LLC, Jay Graham, WHR Incentive LLC, Anthony Bahr and Range Resources Corporation dated as of May 15, 2016 (incorporated by reference to Exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 19, 2016)
10.12	Voting Support and Nomination Agreement, dated as of August 7, 2016, by and among Range Resources Corporation, SailingStone Capital Partners LLC, SailingStone Holdings LLC, MacKenzie B. Davis and Kenneth L. Settles Jr. (incorporated by reference to Exhibit 99.1 to our Current Report on Form 8-K (File No. 001-12209) as filed with the SEC on August 8, 2016)
21.1*	Subsidiaries of Registrant
23.1*	Consent of Independent Registered Public Accounting Firm
23.2*	Consent of Wright & Company Inc., independent consulting engineers
23.3*	Consent of Netherland, Sewell & Associates, Inc., independent consulting engineers
31.1*	Certification by the Chairman and Chief Executive Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification by the Chief Financial Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Certification by the Chairman and Chief Executive Officer of Range Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification by the Chief Financial Officer of Range Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	Report of Wright & Company Inc., independent consulting engineers
99.2*	Report of Netherland, Sewell & Associates, Inc. independent consulting engineers
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith.
** Furnished herewith.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

RANGE RESOURCES CORPORATION

By: /s/ JEFFREY L. VENTURA

Jeffrey L. Ventura
Chairman of the Board, President and Chief Executive Officer
(principal executive officer)

Dated: February 27, 2018

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacity and on the dates indicated.

Signature	Capacity	Date
/s/ JEFFREY L. VENTURA **Jeffrey L. Ventura**	Chairman of the Board, President and Chief Executive Officer (principal executive officer)	February 27, 2018
/s/ ROGER S. MANNY **Roger S. Manny**	Executive Vice President and Chief Financial Officer (principal financial officer)	February 27, 2018
/s/ DORI A. GINN **Dori A. Ginn**	Senior Vice President, Controller and Principal Accounting Officer	February 27, 2018
/s/ BRENDA A. CLINE **Brenda A. Cline**	Director	February 27, 2018
/s/ ANTHONY V. DUB **Anthony V. Dub**	Director	February 27, 2018
/s/ ALLEN FINKELSON **Allen Finkelson**	Director	February 27, 2018
/s/ JAMES M. FUNK **James M. Funk**	Lead Independent Director	February 27, 2018
/s/ CHRISTOPHER A. HELMS **Christopher A. Helms**	Director	February 27, 2018
/s/ ROBERT A. INNAMORATI **Robert A. Innamorati**	Director	February 27, 2018
/s/ MARY RALPH LOWE **Mary Ralph Lowe**	Director	February 27, 2018
/s/ GREG G. MAXWELL **Greg G. Maxwell**	Director	February 27, 2018
/s/ KEVIN S. MCCARTHY **Kevin S. McCarthy**	Director	February 27, 2018
/s/ STEFFEN E. PALKO **Steffen E. Palko**	Director	February 27, 2018

RANGE RESOURCES®