# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION
**WASHINGTON, D.C. 20549**

# FORM 10-Q

**(Mark one)**

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the quarterly period ended September 30, 2018**

**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**<br>**(State or Other Jurisdiction of Incorporation or Organization)** | **34-1312571**<br>**(IRS Employer Identification No.)** |
| **100 Throckmorton Street, Suite 1200**<br>**Fort Worth, Texas**<br>**(Address of Principal Executive Offices)** | **76102**<br>**(Zip Code)** |

**Registrant's telephone number, including area code**
**(817) 870-2601**

Former Name, Former Address and Former Fiscal Year, if changed since last report: Not applicable

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for shorter period that the registrant was required to submit such files).

Yes ☑ No ☐

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

| | | | |
|---|---|---|---|
| Large Accelerated Filer | ☑ | Accelerated Filer | ☐ |
| Non-Accelerated Filer | ☐ | 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 Exchange Act).

Yes ☐ No ☑

249,505,145 Common Shares were outstanding on October 19, 2018

**RANGE RESOURCES CORPORATION**
**FORM 10-Q**
**Quarter Ended September 30, 2018**

*Unless the context otherwise indicates, all references in this report to "Range Resources," "Range," "we," "us," or "our" are to Range Resources Corporation and its directly and indirectly owned subsidiaries. For certain industry specific terms used in the Form 10-Q, please see "Glossary of Certain Defined Terms" in our 2017 Annual Report on Form 10-K.*

## TABLE OF CONTENTS

**PART I – FINANCIAL INFORMATION**

**ITEM 1. Financial Statements**

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

| | September 30, 2018 (Unaudited) | December 31, 2017 |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 357 | $ 448 |
| Accounts receivable, less allowance for doubtful accounts of $5,862 and $7,111 | 397,536 | 348,833 |
| Derivative assets | 103 | 58,607 |
| Inventory and other | 24,488 | 21,346 |
| Total current assets | 422,484 | 429,234 |
| Derivative assets | 1,114 | 273 |
| Goodwill | 1,641,197 | 1,641,197 |
| Natural gas and oil properties, successful efforts method | 13,643,196 | 13,216,453 |
| Accumulated depletion and depreciation | (3,929,060) | (3,649,716) |
| | 9,714,136 | 9,566,737 |
| Other property and equipment | 112,404 | 114,361 |
| Accumulated depreciation and amortization | (101,402) | (99,695) |
| | 11,002 | 14,666 |
| Other assets | 76,203 | 76,734 |
| **Total assets** | $ 11,866,136 | $ 11,728,841 |
| **Liabilities** | | |
| Current liabilities: | | |
| Accounts payable | $ 225,874 | $ 343,871 |
| Asset retirement obligations | 6,327 | 6,327 |
| Accrued liabilities | 386,671 | 317,531 |
| Accrued interest | 37,739 | 43,511 |
| Derivative liabilities | 97,256 | 44,233 |
| Total current liabilities | 753,867 | 755,473 |
| Bank debt | 1,257,199 | 1,208,467 |
| Senior notes | 2,855,048 | 2,851,754 |
| Senior subordinated notes | 48,653 | 48,585 |
| Deferred tax liabilities | 731,723 | 693,356 |
| Derivative liabilities | 11,751 | 9,789 |
| Deferred compensation liabilities | 86,794 | 101,102 |
| Asset retirement obligations and other liabilities | 303,813 | 286,043 |
| Total liabilities | 6,048,848 | 5,954,569 |
| 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, 249,504,124 issued at September 30, 2018 and 248,144,397 issued at December 31, 2017 | 2,495 | 2,481 |
| Common stock held in treasury, 10,067 shares at September 30, 2018 and 14,967 shares at December 31, 2017 | (404) | (599) |
| Additional paid-in capital | 5,617,371 | 5,577,732 |
| Accumulated other comprehensive loss | (1,124) | (1,332) |
| Retained earnings | 198,950 | 195,990 |
| Total stockholders' equity | 5,817,288 | 5,774,272 |
| **Total liabilities and stockholders' equity** | $ 11,866,136 | $ 11,728,841 |

The accompanying notes are an integral part of these consolidated financial statements.

**RANGE RESOURCES CORPORATION**
**CONSOLIDATED STATEMENTS OF OPERATIONS**
**(Unaudited, in thousands, except per share data)**

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2018** | **2017** | **2018** | **2017** |
| **Revenues and other income:** | | | | |
| Natural gas, NGLs and oil sales | $ 736,431 | $ 507,541 | $ 2,094,450 | $ 1,573,128 |
| Derivative fair value (loss) income | (34,591) | (88,426) | (151,890) | 188,326 |
| Brokered natural gas, marketing and other | 109,385 | 63,117 | 267,448 | 170,544 |
| Total revenues and other income | 811,225 | 482,232 | 2,210,008 | 1,931,998 |
| **Costs and expenses:** | | | | |
| Direct operating | 30,926 | 36,888 | 104,136 | 96,331 |
| Transportation, gathering, processing and compression | 304,562 | 191,645 | 819,100 | 560,883 |
| Production and ad valorem taxes | 9,427 | 11,993 | 29,493 | 31,125 |
| Brokered natural gas and marketing | 116,080 | 59,773 | 274,421 | 169,180 |
| Exploration | 8,299 | 22,767 | 23,517 | 45,769 |
| Abandonment and impairment of unproved properties | 6,549 | 42,568 | 73,244 | 52,181 |
| General and administrative | 43,722 | 53,035 | 159,722 | 152,853 |
| Termination costs | (336) | (47) | (373) | 4,049 |
| Deferred compensation plan | 223 | (9,203) | (559) | (36,838) |
| Interest | 54,801 | 49,179 | 161,048 | 144,206 |
| Depletion, depreciation and amortization | 164,266 | 159,749 | 487,558 | 462,074 |
| Impairment of proved properties | — | 63,679 | 22,614 | 63,679 |
| Loss (gain) on the sale of assets | 30 | (102) | (149) | (23,509) |
| Total costs and expenses | 738,549 | 681,924 | 2,153,772 | 1,721,983 |
| **Income (loss) before income taxes** | 72,676 | (199,692) | 56,236 | 210,015 |
| Income tax expense (benefit): | | | | |
| Current | — | — | — | — |
| Deferred | 24,137 | (71,992) | 38,295 | 98,054 |
| | 24,137 | (71,992) | 38,295 | 98,054 |
| **Net income (loss)** | $ 48,539 | $ (127,700) | $ 17,941 | $ 111,961 |
| **Net income (loss) per common share:** | | | | |
| Basic | $ 0.19 | $ (0.52) | $ 0.07 | $ 0.45 |
| Diluted | $ 0.19 | $ (0.52) | $ 0.07 | $ 0.45 |
| Dividends paid per common share | $ 0.02 | $ 0.02 | $ 0.06 | $ 0.06 |
| **Weighted average common shares outstanding:** | | | | |
| Basic | 246,451 | 245,244 | 246,016 | 245,027 |
| Diluted | 247,166 | 245,244 | 246,879 | 245,280 |

The accompanying notes are an integral part of these consolidated financial statements.

**RANGE RESOURCES CORPORATION**
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)**
**(Unaudited, in thousands)**

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2018** | **2017** | **2018** | **2017** |
| **Net income (loss)** | $ 48,539 | $ (127,700) | $ 17,941 | $ 111,961 |
| Other comprehensive income: | | | | |
| Postretirement benefits: | | | | |
| Prior service cost | 91 | — | 276 | — |
| Income tax benefit | (22) | — | (68) | — |
| **Total comprehensive income (loss)** | $ 48,608 | $ (127,700) | $ 18,149 | $ 111,961 |

The accompanying notes are an integral part of these consolidated financial statements.

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited, in thousands)

| | Nine Months Ended September 30, 2018 | Nine Months Ended September 30, 2017 |
|---|---|---|
| **Operating activities:** | | |
| Net income | $ 17,941 | $ 111,961 |
| Adjustments to reconcile net income to net cash provided from operating activities: | | |
| Deferred income tax expense | 38,295 | 98,054 |
| Depletion, depreciation and amortization and impairment | 510,172 | 525,753 |
| Exploration dry hole costs | 4 | 9,166 |
| Abandonment and impairment of unproved properties | 73,244 | 52,181 |
| Derivative fair value loss (income) | 151,890 | (188,326) |
| Cash settlements on derivative financial instruments | (40,272) | 16,062 |
| Allowance for bad debts | (1,250) | 1,050 |
| Amortization of deferred financing costs and other | 4,163 | 4,184 |
| Deferred and stock-based compensation | 41,252 | 3,937 |
| Gain on the sale of assets | (149) | (23,509) |
| Changes in working capital: | | |
| Accounts receivable | (49,713) | (39,694) |
| Inventory and other | (822) | (1,504) |
| Accounts payable | (6,529) | 44,715 |
| Accrued liabilities and other | 36,721 | (13,498) |
| Net cash provided from operating activities | 774,947 | 600,532 |
| **Investing activities:** | | |
| Additions to natural gas and oil properties | (781,554) | (771,067) |
| Additions to field service assets | (1,230) | (4,687) |
| Acreage purchases | (50,461) | (46,967) |
| Proceeds from disposal of assets | 24,339 | 27,583 |
| Purchases of marketable securities held by the deferred compensation plan | (34,953) | (25,410) |
| Proceeds from the sales of marketable securities held by the deferred compensation plan | 37,311 | 28,755 |
| Net cash used in investing activities | (806,548) | (791,793) |
| **Financing activities:** | | |
| Borrowings on credit facilities | 1,602,000 | 1,486,000 |
| Repayments on credit facilities | (1,547,000) | (1,282,000) |
| Repayment of senior notes | — | (500) |
| Dividends paid | (14,950) | (14,876) |
| Debt issuance costs | (8,257) | (247) |
| Taxes paid for shares withheld | (3,143) | (6,971) |
| Change in cash overdrafts | (5,653) | 5,588 |
| Proceeds from the sales of common stock held by the deferred compensation plan | 8,513 | 4,482 |
| Net cash provided from financing activities | 31,510 | 191,476 |
| **(Decrease) increase in cash and cash equivalents** | (91) | 215 |
| **Cash and cash equivalents at beginning of period** | 448 | 314 |
| **Cash and cash equivalents at end of period** | $ 357 | $ 529 |

The accompanying notes are an integral part of these consolidated financial statements.

## (1) SUMMARY OF ORGANIZATION AND NATURE OF BUSINESS

Range Resources Corporation is a Fort Worth, Texas-based independent natural gas, natural gas liquids ("NGLs") and oil company primarily engaged in the exploration, development and acquisition of natural gas and oil properties in the Appalachian and the North Louisiana regions of the United States. Our objective is to build stockholder value through consistent returns-focused 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) BASIS OF PRESENTATION

These consolidated financial statements are unaudited but, in the opinion of management, reflect all adjustments necessary for fair presentation of the results for the periods presented. All adjustments are of a normal recurring nature unless otherwise disclosed. These consolidated financial statements, including selected notes, have been prepared in accordance with the applicable rules of the SEC and do not include all of the information and disclosures required by accounting principles generally accepted in the United States of America ("U.S. GAAP") for complete financial statements.

These interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Range Resources Corporation 2017 Annual Report on Form 10-K filed with the Securities and Exchange Commission (the "SEC") on February 28, 2018. The results of operations for the third quarter and the nine months ended September 30, 2018 are not necessarily indicative of the results to be expected for the full year.

*Inventory.* As of September 30, 2018, we had $9.1 million of material and supplies inventory compared to $12.1 million at December 31, 2017. Material and supplies inventory consists of primarily tubular goods and equipment used in our operations and is stated at lower of specific cost of each inventory item or net realized value, on a first-in, first-out basis. At September 30, 2018, we also had commodity inventory of $1.5 million compared to $508,000 at December 31, 2017. Commodity inventory as of September 30, 2018 consists of NGLs held in storage or as line fill in pipelines.

*Unproved Properties.* 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. In certain circumstances, our future plans to develop acreage may accelerate our impairment.

## (3) NEW ACCOUNTING STANDARDS

### Not Yet Adopted

*Lease Accounting Standard*

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 standard does not apply to leases to explore for or use minerals, oil or natural gas resources, including the right to explore for those natural resources and rights to use the land in which those natural resources are contained. We are evaluating each of our lease arrangements and are currently enhancing our systems to track and calculate additional information necessary for adoption of this standard. 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 and financial disclosures, in addition to developing any control changes necessary. While we have yet to finalize the impact this standards update will have on our consolidated financial statements, we believe the adoption will likely increase our recorded assets and liabilities related to our leases.

We will adopt this new standards update in first quarter 2019 using a modified retrospective approach and will recognize a right of use asset and lease liability on the adoption date. We plan to apply practical expedients provided in the standards update that allow, among other things, not to reassess contracts that commenced prior to the adoption. We also anticipate to elect a policy not to recognize right of use assets and lease liabilities related to short-term leases.

*Financial Instruments – Credit Losses*

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 through 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 and financial disclosures.

*Fair Value Measurement*

In August 2018, an accounting standards update was issued which provides additional disclosure requirements for fair value measurements. This new standards update eliminates the requirement to disclose transfers between Level 1 and Level 2 of the fair value hierarchy and provides for additional disclosures for Level 3 fair value measurements. This new standards update is effective for us in first quarter 2020 and will be adopted on a prospective or retrospective basis depending on the changes that apply. We are evaluating the provisions of this standards update and assessing the impact, if any, it may have on our financial disclosures.

**Recently Adopted**

*Pension Accounting Standard*

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 arising from services rendered during the period. This new standards update was effective for annual reporting periods in first quarter 2018 and must be applied retrospectively. We adopted this standards update in first quarter 2018. The adoption did not impact our consolidated results of operations, financial position, cash flows or disclosures. We had no service cost recorded prior to 2018 due to the implementation of our postretirement benefit plan at the end of 2017. In 2018, our service cost is recorded in general and administrative expense.

*Modification of Share – Based Awards*

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. We adopted this standards update in first quarter 2018. The adoption of this standard did not have a material impact on our consolidated financial position or results of operations.

*Revenue Recognition Standard*

In May 2014, an accounting standards update was issued that superseded the existing revenue recognition requirements. This standard included 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 eliminated industry-specific revenue guidance, required enhanced disclosures about revenue, provided guidance for transactions that were not previously addressed comprehensively and improved guidance for multiple-element arrangements. This standard was effective for us in first quarter 2018 and we adopted the new standards using the modified retrospective method to all open contracts as of January 1, 2018. Our implementation of this standard did not result in a cumulative-effect adjustment on date of adoption; however, our financial statement presentation related to revenue received from certain gas processing contracts changed. Based on previous accounting guidance, certain of our gas processing contracts were reported in revenue at the net price (net of processing costs) we receive. Upon adoption of this accounting standards update, these contracts are now reported as a gross price received at a delivery point and separate transportation, marketing and processing expense. The impact of adoption of the new revenue recognition standard on our current period results is as follows (in thousands):

| | Three Months Ended September 30, 2018 | | | | | |
|---|---|---|---|---|---|---|
| | As Reported | | Previous Revenue Recognition Method | | | |
| | $ | $ Per mcfe | $ | $ Per mcfe | Increase | $ Per mcfe |
| **Revenues:** | | | | | | |
| Natural gas, NGLs and oil sales | $ 736,431 | $ 3.53 | $ 688,684 | $ 3.30 | $ 47,747 | $ 0.23 |
| **Costs and expenses:** | | | | | | |
| Transportation, gathering, processing and compression | $ 304,562 | $ 1.46 | $ 256,815 | $ 1.23 | $ 47,747 | $ 0.23 |
| **Net income** | $ 48,539 | | $ 48,539 | | $ — | |

| | Nine Months Ended September 30, 2018 | | | | | |
|---|---|---|---|---|---|---|
| | As Reported | | Previous Revenue Recognition Method | | | |
| | $ | $ Per mcfe | $ | $ Per mcfe | Increase | $ Per mcfe |
| **Revenues:** | | | | | | |
| Natural gas, NGLs and oil sales | $ 2,094,450 | $ 3.45 | $ 1,966,731 | $ 3.24 | $ 127,719 | $ 0.21 |
| **Costs and expenses:** | | | | | | |
| Transportation, gathering, processing and compression | $ 819,100 | $ 1.35 | $ 691,381 | $ 1.14 | $ 127,719 | $ 0.21 |
| **Net income** | $ 17,941 | | $ 17,941 | | $ — | |

Changes to natural gas, NGLs and oil sales and transportation, gathering, processing, and compression expenses is due to the conclusion that we represent the role of principal in a certain gas processing and marketing agreement with a midstream entity in accordance with the new accounting standard. This represents a change from our previous conclusion utilizing the principal versus agent indication that we acted as the agent in that agreement. As a result, we were required to modify our presentation to present revenue on a gross basis for amounts expected to be received from third-party customers through the marketing process, with expenses incurred prior to control of the products transferring to the midstream entity at the tailgate of the plant presented as transportation, gathering, processing and compression expense.

*Goodwill Standard*

In January 2017, an accounting standards update was issued that eliminates the requirements to calculate the implied fair value of goodwill to measure 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 disclosures; however, this standard did change our policy for our annual goodwill impairment assessment by eliminating the requirement to calculate the implied fair value of goodwill.

*Inventory Standard*

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.

*Classification in the Statement of 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 fourth quarter 2017 on a retrospective basis. Adoption of this standard did not have an impact on our consolidated cash flow statement presentation.

*Definition of a Business*

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 fourth quarter 2017. Adoption of this standard did not have a significant impact on our consolidated results of operations, financial position or cash flows.

**(4) DISPOSITIONS**

We recognized a pretax net loss on the sale of assets of $30,000 in third quarter 2018 compared to a pretax net gain of $102,000 in the same period of the prior year and a pretax net gain on the sale of assets of $149,000 in first nine months 2018 compared to a pretax net gain on the sale of assets of $23.5 million in first nine months 2017.

**2018 Fourth Quarter Disposition Announcement**

On October 15, 2018, we announced the simultaneous signing and closing of an agreement to sell a proportionately reduced 1% royalty on all our current Washington County, Pennsylvania leases for $300.0 million in proceeds. The transaction is subject to customary terms and conditions.

**2018 Dispositions**

*Northern Oklahoma.* In third quarter 2018, we sold properties in Northern Oklahoma for proceeds of $23.3 million and we recorded a net loss of $39,000 related to this sale, after closing adjustments.

*Other*. In third quarter 2018, we sold miscellaneous inventory and other assets for proceeds of $673,000, resulting in a pretax gain of $9,000. In first six months 2018, we sold miscellaneous inventory and other assets for proceeds of $366,000 resulting in a pretax gain of $179,000.

**2017 Dispositions**

*Western Oklahoma.* In first nine months 2017, we sold 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.

*Other*. In third quarter 2017, we sold miscellaneous inventory and other assets for proceeds of $295,000, resulting in a pretax gain of $102,000. In first six months 2017, we sold miscellaneous unproved property, inventory and other assets for proceeds of $1.3 million resulting in a pretax gain of $1.3 million.

## (5) REVENUES FROM CONTRACTS WITH CUSTOMERS

### Revenue Recognition

Natural gas, NGLs and oil sales revenues are generally recognized at the point in time that control of the product is transferred to the customer and collectability is reasonably assured. See a more detailed summary of our product types below.

*Natural Gas and NGLs Sales*

Under our gas processing contracts, we deliver natural gas to a midstream processing entity at the wellhead or the inlet of the midstream processing entity's system. The midstream processing entity processes the natural gas and remits proceeds to us for the resulting sales of NGLs and residue gas. In these scenarios, we evaluate whether we are the principal or the agent in the transaction. For those contracts that we have concluded that we are the principal, the ultimate third party is our customer and we recognize revenue on a gross basis, with gathering, compression, processing, and transportation fees presented as an expense. Alternatively, for those contracts that we have concluded that we are the agent, the midstream processing entity is our customer and we recognize revenue based on the net amount of the proceeds received from the midstream processing entity.

In certain natural gas processing agreements, we may elect to take our residue gas and/or NGLs in-kind at the tailgate of the midstream entity's processing plant and subsequently market the product on our own. Through the marketing process, we deliver product to the ultimate third party purchaser at a contractually agreed upon delivery point and receive a specified index price from the purchaser. In this scenario, we recognize revenue when control transfers to the purchaser at the delivery point based on the index price received from the purchaser. The gathering, processing and compression fees attributable to the gas processing contract, as well as any transportation fees incurred to deliver the product to the purchaser, are presented as transportation, gathering, processing and compression expense.

*Oil Sales*

Our oil sales contracts are generally structured in one of the following ways:

- We sell oil production at the wellhead and collect an agreed upon index price, net of transportation incurred by the purchaser (that is, a netback arrangement). In this scenario, we recognize revenue when control transfers to the purchaser at the wellhead at the net price received.
- We deliver oil to the purchaser at a contractually agreed upon delivery point at which the purchaser takes custody, title, and risk of loss of the product. Under this arrangement, we pay a third party to transport the product and receive a specified index price from the purchaser with no deduction. In this scenario, we recognize revenue when control transfers to the purchaser at the delivery point based on the price received from the purchaser. The third party costs are recorded as transportation, gathering, processing and compression expense.

*Brokered Natural Gas, Marketing and Other*

We realize brokered margins as a result of buying natural gas or NGLs utilizing separate purchase transactions, generally with separate counterparties and subsequently selling that natural gas or NGLs under our existing contracts to fulfill our contract commitments or utilizing existing infrastructure contracts to economically utilize available capacity. In these arrangements, we take control of the natural gas purchased prior to delivery of that gas under our existing gas contracts with a separate counterparty. Revenues and expenses related to brokering 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 $6.7 million in third quarter 2018 and a loss of $7.0 million in first nine months 2018.

**Disaggregation of Revenue**

We have identified three material revenue streams in our business: natural gas sales, NGLs sales and oil sales. Brokered revenue attributable to each product sales type is included here because the volume of product that we purchase is subsequently sold to separate counterparties in accordance with existing sales contracts under which we also sell our production. Revenue attributable to each of our identified revenue streams is disaggregated below (in thousands):

| | Three Months Ended September 30, 2018 | Nine Months Ended September 30, 2018 |
|---|---|---|
| Natural gas sales (a) | $ 500,194 | $ 1,449,148 |
| NGLs sales (b) | 278,410 | 706,673 |
| Oil sales | 67,212 | 206,077 |
| Total | $ 845,816 | $ 2,361,898 |

(a) Natural gas sales revenue reported above for the third quarter includes $105.8 million of brokered revenues and $3.7 million of marketing revenue. The nine months includes $255.1 million of brokered revenues and $11.4 million of marketing revenue.

(b) NGLs sales revenue reported above for the third quarter includes ($153,000) of brokered revenues and for nine months includes $880,000 of brokered revenues.

**Principal versus Agent**

We engage in various types of transactions in which midstream entities process our wet gas and, in some scenarios, subsequently market the resulting NGLs and residue gas to third-party customers on our behalf. These types of transactions require judgment to determine whether we are the principal or the agent in the contract and, as a result, whether revenues are recorded gross or net.

**Transaction Price Allocated to Remaining Performance Obligations**

A significant number of our product sales are short-term in nature with a contract term of one year or less. For those contracts, we have utilized the practical expedient allowed in the new revenue accounting standard that exempts us from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For our product sales that have a contract term greater than one year, we have also utilized the practical expedient that states that we are not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required. Currently, our product sales that have a contractual term greater than one year have no long-term fixed consideration.

**Contract Balances**

Under our sales contracts, we invoice customers once our performance obligations have been satisfied, at which point payment is unconditional. Accordingly, our product sales contracts do not give rise to contract assets or liabilities. Accounts receivable attributable to our revenue contracts with customers was $354.4 million at September 30, 2018 and $305.7 million at December 31, 2017.

**Prior−Period Performance Obligations**

We record revenue in the month production is delivered to the purchaser. However, settlement statements for certain gas and NGLs sales may be received for 30 to 90 days after the date production is delivered, and as a result, we are required to estimate the amount of production that was delivered to the purchaser and the price that will be received for the sale of the product. We record the differences between our estimates and the actual amounts for product sales in the month that payment is received from the purchaser. We have internal controls in place for our estimation process and any identified differences between our revenue estimates and actual revenue received historically have not been significant. For the three months and the nine months ended September 30, 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

**(6) INCOME TAXES**

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Income tax expense (benefit) | $ 24,137 | $ (71,992) | $ 38,295 | $ 98,054 |
| Effective tax rate | 33.2% | 36.1% | 68.1% | 46.7% |

We compute our quarterly taxes under the effective tax rate method based on applying an anticipated annual effective rate to our year-to-date income, except for discrete items. Income taxes for discrete items are computed and recorded in the period that the specific transaction occurs. For third quarter and first nine months ended 2018 and 2017, our overall effective tax rate was different than the federal statutory rate due primarily to state income taxes (including adjustments to state income tax valuation allowances), equity compensation and other tax items which are detailed below (in thousands).

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Total income (loss) before income taxes | $ 72,676 | $ (199,692) | $ 56,236 | $ 210,015 |
| U.S. federal statutory rate | 21% | 35% | 21% | 35% |
| Total tax expense (benefit) at statutory rate | 15,262 | (69,892) | 11,810 | 73,505 |
| State and local income taxes, net of federal benefit | 2,691 | (6,537) | 3,439 | 6,591 |
| Non-deductible executive compensation | 48 | 296 | 601 | 436 |
| Equity compensation | 6 | 56 | 2,146 | 4,808 |
| Change in valuation allowances: | | | | |
| Federal net operating loss carryforwards & other | — | 69 | — | 3,487 |
| State net operating loss carryforwards & other | 5,558 | 4,286 | 19,194 | 10,498 |
| Rabbi trust and other | 100 | (508) | 1,499 | (1,561) |
| Permanent differences and other | 472 | 238 | (394) | 290 |
| Total expense (benefit) for income taxes | $ 24,137 | $ (71,992) | $ 38,295 | $ 98,054 |
| Effective tax rate | 33.2% | 36.1% | 68.1% | 46.7% |

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 was signed into law. The law significantly reformed 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%. Due to the complexities involved in the accounting for the enactment of the new law, the SEC Staff Accounting Bulletin (“SAB”) 118 allowed a provisional estimate for the year ended December 31, 2017, which we made. As of September 30, 2018, we have not made any material adjustments to our provisional estimate at year-end 2017. 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 provided for in SAB 118.

**(7) INCOME (LOSS) PER COMMON SHARE**

Basic income or loss per share attributable to common shareholders is computed as (1) income or loss attributable to common shareholders (2) less income allocable to participating securities (3) divided by weighted average basic shares outstanding. Diluted income or loss per share attributable to common shareholders is computed as (1) basic income or loss attributable to common shareholders (2) plus diluted adjustments to income allocable to participating securities (3) divided by weighted average diluted shares outstanding. The following sets forth a reconciliation of income or loss attributable to common shareholders to basic income or loss attributable to common shareholders to diluted income or loss attributable to common shareholders (in thousands except per share amounts):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Net income (loss), as reported | $ 48,539 | $ (127,700) | $ 17,941 | $ 111,961 |
| Participating earnings [(a)] | (590) | (58) | (224) | (1,251) |
| Basic net income (loss) attributed to common shareholders | 47,949 | (127,758) | 17,717 | 110,710 |
| Reallocation of participating earnings [(a)] | 2 | — | — | 1 |
| Diluted net income (loss) attributed to common shareholders | $ 47,951 | $ (127,758) | $ 17,717 | $ 110,711 |
| Net income (loss) per common share: | | | | |
| Basic | $ 0.19 | $ (0.52) | $ 0.07 | $ 0.45 |
| Diluted | $ 0.19 | $ (0.52) | $ 0.07 | $ 0.45 |

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

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Weighted average common shares outstanding – basic | 246,451 | 245,244 | 246,016 | 245,027 |
| Effect of dilutive securities: | | | | |
| Director and employee PSUs and RSUs | 715 | — | 863 | 253 |
| Weighted average common shares outstanding – diluted | 247,166 | 245,244 | 246,879 | 245,280 |

Weighted average common shares outstanding-basic for third quarter 2018 excludes 3.0 million shares of restricted stock held in our deferred compensation plan compared to 2.9 million shares in third quarter 2017 (although all awards are issued and outstanding upon grant). Weighted average common shares outstanding-basic for first nine months 2018 excludes 3.1 million shares of restricted stock compared to 2.8 million for first nine months 2017. For third quarter 2018, equity grants of 506,000 and for first nine months 2018, equity grants of 755,000 were outstanding but not included in the computation of diluted net income per share because the grant prices were greater than the average market price of our common shares and would be anti-dilutive to the computations. Due to our net loss in third quarter 2017, all outstanding equity grants have been excluded from the computation of diluted net loss per share because the effect would have been anti-dilutive to the computations. For first nine months 2017, equity grants of 1.1 million were outstanding but not included in the computation of diluted net income per share because the grant prices were greater than the average market price of our common shares and would be anti-dilutive to the computations. For purposes of calculating diluted weighted average common shares, non-vested 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.

## (8) CAPITALIZED COSTS AND ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION [(a)]

| | September 30, 2018 | December 31, 2017 |
|---|---|---|
| | (in thousands) | |
| Natural gas and oil properties: | | |
| Properties subject to depletion | $ 11,041,412 | $ 10,572,453 |
| Unproved properties | 2,601,784 | 2,644,000 |
| Total | 13,643,196 | 13,216,453 |
| Accumulated depreciation, depletion and amortization | (3,929,060) | (3,649,716) |
| Net capitalized costs | $ 9,714,136 | $ 9,566,737 |

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

## (9) INDEBTEDNESS

We had the following debt outstanding as of the dates shown below (bank debt interest rate at September 30, 2018 is shown parenthetically). No interest was capitalized during the three months or nine months ended September 30, 2018 or the year ended December 31, 2017 (in thousands).

| | September 30, 2018 | December 31, 2017 |
|---|---|---|
| **Bank debt** (3.9%) | $ 1,266,000 | $ 1,211,000 |
| **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 | 329,244 | 329,244 |
| Other senior notes due 2022 | 590 | 590 |
| Total senior notes | 2,877,349 | 2,877,349 |
| **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 | 4,192,329 | 4,137,329 |
| Unamortized premium | 5,070 | 6,027 |
| Unamortized debt issuance costs | (36,499) | (34,550) |
| **Total debt net of debt issuance costs** | $ 4,160,900 | $ 4,108,806 |

### Bank Debt

In April 2018, 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 and has a maturity date of April 13, 2023. The bank credit facility provides for a maximum facility amount of $4.0 billion and an initial borrowing base of $3.0 billion. The bank credit facility provides for a borrowing base subject to redeterminations annually by May and for event-driven unscheduled redeterminations. As of September 30, 2018, our bank group was composed of twenty-seven 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. On September 30, 2018, bank commitments total $2.0 billion and the outstanding balance under our bank credit facility was $1.3 billion, before deducting debt issuance costs. Additionally, we had $281.4 million of undrawn letters of credit leaving $452.6 million of committed borrowing capacity available under the facility. During a non-investment grade period, borrowings under the bank credit facility can either be at the alternate base rate (“ABR,” as defined in the bank credit facility agreement) plus a spread ranging from 0.25% to 1.25% or LIBOR borrowings at the LIBOR Rate (as defined in the bank credit facility 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 base rate loans or to convert all or any of the base rate loans to LIBOR loans. The weighted average interest rate was 3.9% for third quarter 2018 compared to 2.8% for third quarter 2017. The weighted average interest rate was 3.7% for first nine months 2018 compared to 2.6% for first nine months 2017. A commitment fee is paid on the undrawn balance based on an annual rate of 0.30% to 0.375%. At September 30, 2018, the commitment fee was 0.35% and the interest rate margin was 1.75% on our LIBOR loans and 0.75% on our base rate loans.

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 and an additional financial covenant (as defined in the bank credit facility) will be imposed. During the investment grade period, borrowings under the credit facility can either be at the ABR plus a spread ranging from 0.125% to 0.75% or at the 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 would range from 0.15% to 0.30%. We currently do not have an investment grade debt rating.

**Senior Notes**

In September 2016, in conjunction with the acquisition of Memorial Resource Development Corp. (the "MRD Merger"), we issued $329.2 million senior unsecured 5.875% notes due 2022 (the "5.875% Notes"). In addition, we also completed a debt exchange offer to exchange senior subordinated notes for the following senior notes (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.

**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 aggregate principal amount plus accrued and unpaid interest, if any. All of the senior subordinated notes and the guarantees by our subsidiary guarantors are general, unsecured obligations and are subordinated to our bank debt and are subordinated to existing and future senior debt that we or our subsidiary guarantors are permitted to incur.

**Guarantees**

Range is a holding company which owns no operating assets and has no significant operations independent of its subsidiaries. The guarantees by our subsidiaries, which are directly or indirectly owned by Range, of our senior notes, 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**

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 bank credit facility agreement) to cash interest expense of equal to or greater than 2.5 and a current ratio (as defined in the bank credit facility 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 September 30, 2018.

**(10) ASSET RETIREMENT OBLIGATIONS**

Our asset retirement obligations primarily represent the estimated present value of the amounts we will incur to plug, abandon and remediate our producing properties at the end of their productive lives. Significant inputs used in determining such obligations include estimates of plugging and abandonment costs, estimated future inflation rates and well lives. The inputs are calculated based on historical data as well as current estimated costs. A reconciliation of our liability for plugging and abandonment costs for the nine months ended September 30, 2018 is as follows (in thousands):

| | Nine Months Ended September 30, 2018 |
|---|---|
| Beginning of period | $ 276,855 |
| Liabilities incurred | 2,668 |
| Disposition of wells | (8,665) |
| Acquisitions | 13,438 |
| Liabilities settled | (3,803) |
| Accretion expense | 12,132 |
| Change in estimate | 4,347 |
| End of period | 296,972 |
| Less current portion | (6,327) |
| Long-term asset retirement obligations | $ 290,645 |

Accretion expense is recognized as a component of depreciation, depletion and amortization expense in the accompanying consolidated statements of operations. Acquisitions include an increase in our interest in certain properties in Northwest Pennsylvania.

## (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 utilize commodity swaps, collars, calls or swaptions to (1) reduce the effect of price volatility of the commodities we produce and sell and (2) support our annual capital budget and expenditure plans. The fair value of our derivative contracts, represented by the estimated amount that would be realized upon termination, based on a comparison of the contract price and a reference price, generally the New York Mercantile Exchange ("NYMEX") for natural gas and crude oil or Mont Belvieu for NGLs, approximated a net loss of $104.8 million at September 30, 2018. These contracts expire monthly through December 2020. The following table sets forth our commodity-based derivative volumes by year as of September 30, 2018, excluding our basis and freight swaps which are discussed separately below:

| Period | Contract Type | Volume Hedged | Weighted Average Hedge Price |
|---|---|---|---|
| **Natural Gas** | | | |
| 2018 | Swaps | 1,193,370 Mmbtu/day | $ 2.96 |
| 2019 | Swaps | 594,589 Mmbtu/day | $ 2.82 |
| 2018 | Calls | 70,000 Mmbtu/day | $ 3.10 (1) |
| 2018 | Swaptions | 160,000 Mmbtu/day | $ 3.07 (2) |
| 2019 | Swaptions | 298,014 Mmbtu/day | $ 2.86 (2) |
| 2020 | Swaptions | 10,000 Mmbtu/day | $ 2.75 (2) |
| **Crude Oil** | | | |
| 2018 | Swaps | 8,500 bbls/day | $ 53.20 |
| 2019 | Swaps | 7,000 bbls/day | $ 55.26 |
| 2020 | Swaps | 1,500 bbls/day | $ 60.63 |
| 2019 | Collars | 1,000 bbls/day | $ 63.00 − $ 73.03 |
| **NGLs (C3-Propane)** | | | |
| 2018 | Swaps | 11,668 bbls/day | $ 0.74/gallon |
| January – June 2019 | Swaps | 7,500 bbls/day | $ 0.92/gallon |
| 2018 | Collars | 5,000 bbls/day | $ 0.95 − $ 1.04 |
| January – March 2019 | Collars | 6,500 bbls/day | $ 0.92 − $1.02 |
| **NGLs (NC4-Normal Butane)** | | | |
| 2018 | Swaps | 5,500 bbls/day | $ 0.91/gallon |
| January – March 2019 | Swaps | 2,250 bbls/day | $ 1.22/gallon |
| **NGLs (C5-Natural Gasoline)** | | | |
| 2018 | Swaps | 5,402 bbls/day | $ 1.24/gallon |
| 2019 | Swaps | 2,178 bbls/day | $ 1.42/gallon |

(1) Weighted average deferred premium of $0.16.

(2) Contains a combined derivative instrument consisting of a fixed price swap and a sold option to extend or double the volume. For October through December of 2018, we 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. We have swaps in place for 2019 for 185,000 Mmbtu/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 2019 for 150,000 Mmbtu per day on which the counterparty can elect to extend the contract through December 2020 at a weighted average price of $2.81. For 2020, we have swaps in place for 10,000 Mmbtu/day on which the counterparty can elect to double the volume at a weighted average price of $2.75.

Every derivative instrument is required to be recorded on the balance sheet as either an asset or a liability measured at its fair value. We recognize all changes in fair value of these derivatives as earnings in derivative fair value income or loss in the periods in which they occur.

***Basis Swap Contracts***

In addition to the swaps, collars, calls and swaptions described above, at September 30, 2018, we had natural gas basis swap contracts which lock in the differential between NYMEX Henry Hub and certain of our physical pricing indices. These contracts settle monthly through September 2021 and include a total volume of 73,660,000 Mmbtu. The fair value of these contracts was a loss of $1.3 million at September 30, 2018.

At September 30, 2018, we also had propane spread swap contracts which lock in the differential between Mont Belvieu and international propane indices. The contracts settle monthly through December 2019 and include a total volume of 1,943,000 barrels. The fair value of these contracts was a loss of $2.0 million at September 30, 2018.

***Freight Swap Contracts***

In connection with our international propane sales, we utilize propane swaps. To further hedge our propane price, at September 30, 2018, we had freight swap contracts on the Baltic Exchange which lock in the freight rate for a specific trade route. These contracts settle monthly through December 2019 and cover 5,000 metric tons per month with a fair value gain of $301,000 at September 30, 2018. 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 September 30, 2018 and December 31, 2017 is summarized below. The assets and liabilities are netted where derivatives with both gain and loss positions are held by a single counterparty and we have master netting arrangements. The tables below provide additional information relating to our master netting arrangements with our derivative counterparties (in thousands):

| | | September 30, 2018 | | |
|---|---|---|---|---|
| | | 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 | $ 6,503 | $ (4,745) | $ 1,758 |
| | –swaptions | 12,893 | (12,700) | 193 |
| | –basis swaps | 1,246 | (1,112) | 134 |
| Crude oil | –swaps | — | (799) | (799) |
| | −collars | — | (69) | (69) |
| NGLs | –C3 propane swaps | 3 | (3) | — |
| | –C3 propane spread swaps | 25,747 | (25,747) | — |
| Freight | −swaps | 301 | (301) | — |
| | | $ 46,693 | $ (45,476) | $ 1,217 |

| | | September 30, 2018 | | |
|---|---|---|---|---|
| | | 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 | $ (10,030) | $ 4,745 | $ (5,285) |
| | –swaptions | (8,759) | 12,700 | 3,941 |
| | –basis swaps | (2,548) | 1,112 | (1,436) |
| | –calls | (504) | — | (504) |
| Crude oil | –swaps | (57,424) | 799 | (56,625) |
| | −collars | (717) | 69 | (648) |
| NGLs | –C3 propane swaps | (20,363) | 3 | (20,360) |
| | –C3 propane collars | (3,237) | — | (3,237) |
| | –C3 propane spread swaps | (27,741) | 25,747 | (1,994) |
| | –NC4 butane swaps | (8,223) | — | (8,223) |
| | –C5 natural gasoline swaps | (14,937) | — | (14,937) |
| Freight | –swaps | — | 301 | 301 |
| | | $ (154,483) | $ 45,476 | $ (109,007) |

| | | 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) |

The effects of our derivatives on our consolidated statements of operations are summarized below (in thousands):

| | Derivative Fair Value (Loss) Income | | | |
|---|---|---|---|---|
| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
| | 2018 | 2017 | 2018 | 2017 |
| Commodity swaps | $ (35,868) | $ (87,861) | $ (143,598) | $ 172,457 |
| Swaptions | 7,093 | (7,602) | 4,100 | (7,602) |
| Collars | (3,965) | 956 | (4,031) | 15,221 |
| Puts | — | (73) | — | 9,646 |
| Calls | 197 | 104 | 526 | 1,144 |
| Basis swaps | (2,350) | 6,113 | (9,043) | (2,554) |
| Freight swaps | 302 | (63) | 156 | 14 |
| Total | $ (34,591) | $ (88,426) | $ (151,890) | $ 188,326 |

## (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 fair value.

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

Significant uses of fair value measurements include:

- impairment assessments of long-lived assets;
- impairment assessments of goodwill; and
- recorded value of derivative instruments and trading securities.

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.

***Fair Values – Recurring***

We use a market approach for our recurring fair value measurements and endeavor to use the best information available. The following tables present the fair value hierarchy table for assets and liabilities measured at fair value, on a recurring basis (in thousands):

| | Fair Value Measurements at September 30, 2018 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 September 30, 2018 |
| Trading securities held in the deferred compensation plans | $ 67,108 | $ — | $ — | $ 67,108 |
| Derivatives –swaps | — | (104,471) | — | (104,471) |
| –collars | — | (717) | (3,237) | (3,954) |
| –calls | — | (504) | — | (504) |
| –basis swaps | — | (3,296) | — | (3,296) |
| –freight swaps | — | 301 | — | 301 |
| –swaptions | — | — | 4,134 | 4,134 |

| | 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 |

Our trading securities in Level 1 are exchange-traded and measured at fair value with a market approach using end of period market values. Derivatives in Level 2 are measured at fair value with a market approach using third-party pricing services, which have been corroborated with data from active markets or broker quotes. As of September 30, 2018, a portion of our natural gas derivative instruments contains swaptions where the counterparty has the right, but not the obligation, to enter into a fixed price swap on a pre-determined 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):

| | As of September 30, 2018 |
|---|---|
| Balance at December 31, 2017 | $ 6,658 |
| Total losses: | |
| Included in earnings | 1,876 |
| Settlements | (4,690) |
| Transfer out of Level 3 [1] | (2,947) |
| Balance at September 30, 2018 | $ 897 |

[1] During first nine months 2018, we transferred $2.9 million of swaption contracts out of Level 3 due to the exercise of these swaptions by our counterparties.

Our trading securities held in the deferred compensation plan are accounted for using the mark-to-market accounting method and are included in other assets in the accompanying consolidated balance sheets. We elected to adopt the fair value option to simplify our accounting for the investments in our deferred compensation plan. Interest, dividends, and mark-to-market gains or losses are included in deferred compensation plan expense in the accompanying consolidated statements of operations. For third quarter 2018, interest and dividends were $225,000 and the mark-to-market adjustment was a gain of $1.3 million compared to interest and dividends of $1.5 million and a mark-to-market gain of $1.1 million in third quarter 2017. For first nine months 2018, interest and dividends were $606,000 and the mark-to-market gain was $522,000 compared to interest and dividends of $2.4 million and mark-to-market gain of $4.1 million in the same period of the prior year.

***Fair Values—Goodwill***

During 2016, we recorded goodwill associated with the MRD Merger, which represented the cost of the acquired entity over the net amounts assigned to assets acquired and liabilities assumed. Goodwill is assessed for impairment whenever events or circumstances indicate that impairment of the carrying value of goodwill is likely, but no less often than annually. Our policy is to first assess qualitative factors in order to determine whether fair value is more likely than not less than carrying value. Certain qualitative factors used in our evaluation include, among other things, the result of the most recent quantitative assessment of the goodwill impairment test, macroeconomic conditions; industry and market conditions (including commodity prices and cost factors); overall financial performance; and others relevant entity-specific events. If, after considering these events and circumstances, we determine that it is more likely than not that the fair value is less than carrying value, a quantitative goodwill test is performed. During fourth quarter 2017, we performed our annual qualitative assessment of goodwill to determine whether it was more likely than not that the fair value of our business (our reporting unit) was less than its carrying amount. Based on the results of this assessment, we determined it was not likely that goodwill was impaired. We are not aware of any events or circumstances that occurred during first nine months 2018 that would have more likely than not reduced the fair value of our reporting unit below its carrying value.

***Fair Values—Non-recurring***

Our proved natural gas and oil properties are reviewed for impairment periodically as events or changes in circumstances indicate the carrying amount may not be recoverable. In second quarter 2018, we increased our interest in certain properties in our shallow legacy oil and natural gas assets in Northwest Pennsylvania for a minimal dollar amount for which the fair value was previously determined to be zero. As a result, in second quarter 2018, we recorded additional impairment of $15.3 million related to these properties. In first quarter 2018, there were indicators that the carrying value of certain of our oil gas properties in Oklahoma may be impaired and undiscounted future cash flows attributed to these assets indicated their carrying amounts were not expected to be recovered. Their remaining fair value was measured using a market approach based upon the potential sale of these properties, which is a Level 3 input. We recorded non-cash charges in first quarter 2018 of $7.3 million related to these properties. In third quarter 2017, there were indicators that the carrying value of certain of our properties in Oklahoma and the Texas Panhandle may be impaired and undiscounted future cash flows attributed to these assets indicated their carrying amounts were not expected to be recovered. We also considered the potential sale of these assets. We recorded non-cash charges in third quarter 2017 of $63.7 million related to these properties. The following presents the value of these assets measured at fair value on a non-recurring basis at the time impairment was recorded (in thousands):

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2018 | | 2017 | | 2018 | | 2017 | |
| | Fair Value | Impairment | Fair Value | Impairment | Fair Value | Impairment | Fair Value | Impairment |
| Natural gas and oil properties | $ — | $ — | $ 85,597 | $ 63,679 | $ 32,516 | $ 22,614 | $ 85,597 | $ 63,679 |

***Fair Values—Reported***

The following presents the carrying amounts and the fair values of our financial instruments as of September 30, 2018 and December 31, 2017 (in thousands):

| | September 30, 2018 | | December 31, 2017 | |
|---|---|---|---|---|
| | Carrying Value | Fair Value | Carrying Value | Fair Value |
| Assets: | | | | |
| Commodity swaps, options and basis swaps | $ 1,217 | $ 1,217 | $ 58,880 | $ 58,880 |
| Marketable securities [(a)] | 67,108 | 67,108 | 67,117 | 67,117 |
| (Liabilities): | | | | |
| Commodity swaps, options and basis swaps | (109,007) | (109,007) | (54,022) | (54,022) |
| Bank credit facility [(b)] | (1,266,000) | (1,266,000) | (1,211,000) | (1,211,000) |
| 5.75% senior notes due 2021 [(b)] | (475,952) | (489,555) | (475,952) | (493,872) |
| 5.00% senior notes due 2022 [(b)] | (580,032) | (574,493) | (580,032) | (578,727) |
| 5.875% senior notes due 2022 [(b)] | (329,244) | (334,439) | (329,244) | (339,200) |
| Other senior notes due 2022 [(b)] | (590) | (586) | (590) | (591) |
| 5.00% senior notes due 2023 [(b)] | (741,531) | (728,576) | (741,531) | (735,614) |
| 4.875% senior notes due 2025 [(b)] | (750,000) | (712,193) | (750,000) | (733,755) |
| 5.75% senior subordinated notes due 2021 [(b)] | (22,214) | (22,825) | (22,214) | (22,192) |
| 5.00% senior subordinated notes due 2022 [(b)] | (19,054) | (18,863) | (19,054) | (18,741) |
| 5.00% senior subordinated notes due 2023 [(b)] | (7,712) | (7,567) | (7,712) | (7,614) |
| Deferred compensation plan [(c)] | (112,827) | (112,827) | (114,414) | (114,414) |

(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 include financial instruments, the most significant of which are trade accounts receivable and payable. We believe the carrying values of our current assets and liabilities approximate fair value. Our fair value assessment incorporates a variety of considerations, including (1) the short-term duration of the instruments and (2) our historical and expected incurrence of bad debt expense. Non-financial liabilities initially measured at fair value include asset retirement obligations. For additional information, see Note 10.

**Concentrations of Credit Risk**

As of September 30, 2018, our primary concentrations of credit risk are the risks of not collecting accounts receivable and the risk of a counterparty's failure to perform under derivative obligations. Most of our receivables are from a diverse group of companies, including major energy companies, pipeline companies, local distribution companies, financial institutions and end-users in various industries. Letters of credit or other appropriate securities are obtained as deemed necessary to limit our risk of loss. Our allowance for uncollectable receivables was $5.9 million at September 30, 2018 and $7.1 million at December 31, 2017. Our derivative exposure to credit risk is diversified primarily among major investment grade financial institutions, where we have master netting agreements which provide for offsetting payables against receivables from separate derivative contracts. To manage counterparty risk associated with our derivatives, we select and monitor our counterparties based on our assessment of their financial strength and/or credit ratings. We may also limit the level of exposure with any single counterparty. At September 30, 2018, our derivative counterparties include twenty-one financial institutions, of which all but five are secured lenders in our bank credit facility. At September 30, 2018, our net derivative liability includes a net payable of $23.9 million to these five counterparties that are not participants in our bank credit facility.

## (13) STOCK-BASED COMPENSATION PLANS

**Stock-Based Awards**

We have one active equity-based stock plan, our Amended and Restated 2005 Equity-Based Incentive Compensation Plan, which we refer to as the 2005 Plan. Under this plan, various awards may be issued to non-employee directors and employees pursuant to decisions of the Compensation Committee, which is composed of only non-employee, independent directors. To better align the timing of senior officer equity awards with our proxy statement filing in 2018, senior officer equity grants were in March 2018 rather than May, as in previous years.

**Total Stock-Based Compensation Expense**

Stock-based compensation represents amortization of restricted stock and performance units. Unlike the other forms of stock-based compensation, the mark-to-market adjustment of the liability related to the vested restricted stock held in our deferred compensation plan is directly tied to the change in our stock price and not directly related to the functional expenses and therefore, is not allocated to the functional categories. The following details the allocation of stock-based compensation to functional expense categories (in thousands):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Direct operating expense | $ 537 | $ 517 | $ 1,667 | $ 1,563 |
| Brokered natural gas and marketing expense | 403 | 389 | 1,001 | 1,040 |
| Exploration expense | 405 | 561 | 1,527 | 1,596 |
| General and administrative expense | 5,607 | 9,959 | 38,332 | 35,156 |
| Termination costs | — | (31) | — | 1,665 |
| Total stock-based compensation | $ 6,952 | $ 11,395 | $ 42,527 | $ 41,020 |

***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 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 Awards or "TSR-PSUs").

Each unit granted represents 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 200% based on performance achieved and (2) the value of our common stock on the vesting date which is determined by the Compensation Committee. Dividend equivalents may accrue during the performance period and would be paid in stock at the end of the performance period. The performance period for the TSR-PSUs is three years. The performance period for the PG/RG-PSUs is based on annual performance targets earned over a three-year period.

**SARs**. At September 30, 2018, there were 1,104 SARs outstanding.

**Restricted Stock – *Equity Awards***

In first nine months 2018, we granted 1.8 million restricted stock Equity Awards to employees at an average price of $16.97 which generally vest over a three-year period compared to 883,000 at an average price of $32.81 in first nine months 2017. We recorded compensation expense for these awards of $18.2 million in first nine months 2018 compared to $18.1 million in the same period of 2017. 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 first nine months 2018, we granted 877,000 shares of restricted stock Liability Awards as compensation to employees at an average price of $15.30 which vests generally over a three-year period and 138,000 shares were granted to non-employee directors at an average price of $15.54 with immediate vesting. The timing of equity grants to senior officers was moved to March 2018 to align with our proxy statement filings compared to grants in May in previous years. In first nine months 2017, we granted 451,000 shares of restricted stock Liability Awards as compensation to employees at an average price of $25.95 with vesting generally over a three-year period and 90,000 shares were granted to non-employee directors at an average price of $25.01 with immediate vesting. We recorded compensation expense for these Liability Awards of $11.0 million in first nine months 2018 compared to $12.0 million in first nine months 2017. The majority 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 following is a summary of the status of our non-vested restricted stock outstanding at September 30, 2018:

| | 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, 2017 | 833,058 | $ 31.64 | 55,202 | $ 32.26 |
| Granted | 1,816,432 | 16.97 | 877,191 | 15.30 |
| Vested | (792,382) | 23.76 | (733,634) | 15.99 |
| Forfeited | (191,332) | 21.74 | (23,900) | 19.76 |
| Outstanding at September 30, 2018 | 1,665,776 | $ 20.53 | 174,859 | $ 17.14 |

**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. 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 September 30, 2018:

| | Number of Units | Weighted Average Grant Date Fair Value |
|---|---|---|
| Outstanding at December 31, 2017 | 122,921 | $ 18.66 |
| Units granted (a) | 440,938 | 15.22 |
| Forfeited (b) | (27,061) | 23.03 |
| Outstanding at September 30, 2018 | 536,798 | $ 15.61 |

(a) Amounts granted reflect the number of performance units granted; however, the actual payout of shares will be between zero and 200% depending on achievement of specifically identified performance targets.

(b) The first of three tranches of PG-PSUs granted in 2017 are considered forfeited as the performance metric was not met.

We recorded PG/RG-PSUs compensation expense of $5.8 million in first nine months 2018 compared to $124,000 in first nine months 2017.

***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 first nine months 2018 and 2017:

| | Nine Months Ended September 30, 2018 | Nine Months Ended September 30, 2017 |
|---|---|---|
| Risk-free interest rate | 2.42% | 1.49% |
| Expected annual volatility | 48% | 44% |
| Grant date fair value per unit | $ 18.51 | $ 26.26 |

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, 2017 | 1,009,842 | $ 38.38 |
| Units granted (a) | 329,486 | 18.51 |
| Vested and issued (b) | (73,985) | 56.81 |
| Forfeited | (197,457) | 55.46 |
| Outstanding at September 30, 2018 | 1,067,886 | $ 27.81 |

(a) These amounts reflect the number of performance units granted. The actual payout of shares may be between zero and 200% of the performance units granted depending on the total shareholder return ranking compared to our peer companies at the vesting date.

(b) Includes 73,985 TSR-PSUs awards issued related to the 2015 performance period where the return on our common stock was the 46th percentile for the February 2015 grant and 36th percentile for the May 2015 grant. The remaining 2015 awards are considered to be forfeited.

We recorded TSR-PSUs compensation expense of $6.1 million in first nine months 2018 compared to $9.7 million in the same period of 2017.

**SARs**

Information with respect to our SARs activities is summarized below.

| | Shares | Weighted Average Exercise Price |
|---|---|---|
| Outstanding at December 31, 2017 | 382,779 | $ 76.54 |
| Expired/forfeited | (381,675) | 75.97 |
| Outstanding at September 30, 2018 | 1,104 | $ 81.74 |

***Other Postretirement Benefits***

Effective fourth quarter 2017, as part of our officer succession plan, we implemented a postretirement 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 first nine months 2018, there were $276,000 of estimated prior service costs amortized from accumulated other comprehensive income into general and administrative expense. Those employees that qualify for the new postretirement health care plan are also fully vested in all equity grants.

**Deferred Compensation Plan**

Our deferred compensation plan gives non-employee directors and officers the ability to defer all or a portion of their salaries, bonuses or director fees and invest in Range common stock or make other investments at the individual's discretion. Range provides a partial matching contribution to officers which vests over three years. The assets of the plan are held in a grantor trust, which we refer to as the Rabbi Trust, and are therefore available to satisfy the claims of our general creditors in the event of bankruptcy or insolvency. Our stock held in the Rabbi Trust is treated as a liability award as employees are allowed to take withdrawals from the Rabbi Trust either in cash or in Range stock. The liability for the vested portion of the stock held in the Rabbi Trust is reflected as deferred compensation liability in the accompanying consolidated balance sheets and is adjusted to fair value each reporting period by a charge or credit to deferred compensation plan expense on our consolidated statements of operations. The assets of the Rabbi Trust, other than our common stock, are invested in marketable securities and reported at their market value as other assets in the accompanying consolidated balance sheets. The deferred compensation liability reflects the vested market value of the marketable securities and Range stock held in the Rabbi Trust. Changes in the market value of the marketable securities and changes in the fair value of the deferred compensation plan liability are charged or credited to deferred compensation plan expense each quarter. We recorded mark-to-market loss of $223,000 in third quarter 2018 compared to mark-to-market gain of $9.2 million in third quarter 2017. We recorded mark-to-market gain of $559,000 in first nine months 2018 compared to a mark-to-market gain of $36.8 million in first nine months 2017. The Rabbi Trust held 2.9 million shares (2.7 million of which were vested) of Range stock at September 30, 2018 compared to 2.9 million shares (2.8 million of which were vested) at December 31, 2017.

**(14) CAPITAL STOCK**

We have authorized capital stock of 485.0 million shares which includes 475.0 million shares of common stock and 10.0 million shares of preferred stock. We currently have no preferred stock issued or outstanding. The following is a schedule of changes in the number of common shares outstanding since the beginning of 2017:

| | Nine Months Ended September 30, 2018 | Year Ended December 31, 2017 |
|---|---|---|
| Beginning balance | 248,129,430 | 247,144,356 |
| Restricted stock grants | 853,291 | 539,096 |
| Restricted stock units vested | 430,287 | 344,937 |
| Performance stock units issued | 73,985 | 85,461 |
| Performance stock dividends | 2,164 | — |
| Treasury shares issued | 4,900 | 15,580 |
| Ending balance | 249,494,057 | 248,129,430 |

**(15) SUPPLEMENTAL CASH FLOW INFORMATION**

| | Nine Months Ended September 30, 2018 | Nine Months Ended September 30, 2017 |
|---|---|---|
| | (in thousands) | |
| Net cash provided from operating activities included: | | |
| Income taxes refunded (paid) to taxing authorities | $ 7,521 | $ (98) |
| Interest paid | (161,444) | (136,863) |
| Non-cash investing and financing activities included: | | |
| Increase in asset retirement costs capitalized | 20,452 | 6,460 |
| (Decrease) increase in accrued capital expenditures | (107,070) | 52,289 |

## (16) COMMITMENTS AND CONTINGENCIES

### Litigation

We are the subject of, or party to, a number of pending or threatened legal actions, administrative proceedings and claims arising in the ordinary course of our business. While many of these matters involve inherent uncertainty, we believe that the amount of the liability, if any, ultimately incurred with respect to these actions, 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 estimate and provide for potential losses that may arise out of litigation and regulatory proceedings to the extent that such losses are probable and can be reasonably estimated. We will continue to evaluate our litigation and regulatory proceedings quarterly and will establish and adjust any estimated liability as appropriate to reflect our assessment of the then current status of litigation and regulatory proceedings. Significant judgment is required in making these estimates and our final liabilities may ultimately be materially different.

### Transportation and Gathering Contracts

In first nine months 2018, our transportation and gathering commitments increased by approximately $2.4 billion over the next twenty years (through 2038) primarily due to a new pipeline brought into service in Pennsylvania and pricing changes for current contracts.

## (17) OFFICE CLOSING AND TERMINATION COSTS

In first quarter 2017, we recorded accruals for severance, other personnel costs and accelerated vesting of stock-based compensation as part of a continuing effort to reduce our general and administrative expenses due, in part, to the lower commodity price environment. The following summarizes our termination costs for the three months and nine months ended September 30, 2018 and 2017 (in thousands):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Severance costs | $ (356) | $ — | $ (356) | $ 2,422 |
| Building lease | 20 | (16) | (17) | (37) |
| Stock-based compensation | — | (31) | — | 1,664 |
| Total termination costs | $ (336) | $ (47) | $ (373) | $ 4,049 |

The following details our accrued liability as of September 30, 2018 (in thousands):

| | September 30, 2018 |
|---|---|
| Beginning balance at December 31, 2017 | $ 1,855 |
| Accrued severance costs | (356) |
| Accrued building rent | (17) |
| Payments | (1,417) |
| Ending balance at September 30, 2018 | $ 65 |

## (18) 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 included 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. We do not have any suspended exploratory well costs as of September 30, 2018 or December 31, 2017.

## (19) COSTS INCURRED FOR PROPERTY ACQUISITION, EXPLORATION AND DEVELOPMENT (a)

| | Nine Months Ended September 30, 2018 | Year Ended December 31, 2017 |
|---|---|---|
| | (in thousands) | |
| Acquisitions: | | |
| Acreage purchases | $ 40,811 | $ 62,075 |
| Oil and gas properties | 1,683 | 18,269 |
| Development | 676,896 | 1,177,526 |
| Exploration: | | |
| Drilling | 805 | 2,030 |
| Expense | 21,990 | 50,920 |
| Stock-based compensation expense | 1,527 | 2,742 |
| Gas gathering facilities: | | |
| Development | 6,076 | 15,097 |
| Subtotal | 749,788 | 1,328,659 |
| Asset retirement obligations | 20,452 | 20,245 |
| Total costs incurred | $ 770,240 | $ 1,348,904 |

(a) Includes costs incurred whether capitalized or expensed.

## ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

### Overview of Our Business

We are a Fort Worth, Texas-based independent natural gas, natural gas liquids ("NGLs") and oil company engaged in the exploration, development and acquisition of natural gas and crude oil properties 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 a geographical or 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 on a cost-efficient basis. Our strategy to achieve our business objective is to increase reserves and production through consistent 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 ("crude oil" or "oil") and on our ability to economically find, develop, acquire, produce and market natural gas, NGLs and crude oil reserves. The price risk on a portion of our production is mitigated using commodity derivative contracts. However, these derivative contracts are limited in duration. Prices for natural gas, NGLs and oil fluctuate widely and affect:

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

We prepare our financial statements in conformity with U.S. GAAP which requires 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.

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the preceding consolidated financial statements and notes in Item 1.

### Market Conditions

Prices for our products significantly impact our revenue, net income and cash flow. Natural gas, NGLs and oil are commodities and prices for these commodities are inherently volatile. The following table lists related benchmarks for natural gas, oil and NGLs for the three months and the nine months ended September 30, 2018 and 2017:

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2018 | 2017 | Change | % | 2018 | 2017 | Change | % |
| **Benchmarks** | | | | | | | | |
| Average NYMEX prices [(a)] | | | | | | | | |
| Natural gas (per mcf) | $ 2.91 | $ 3.00 | $ (0.09) | (3%) | $ 2.90 | $ 3.15 | $ (0.25) | (8%) |
| Oil (per bbl) | 69.49 | 48.14 | 21.35 | 44% | 66.78 | 49.35 | 17.43 | 35% |
| Mont Belvieu NGLs composite (per gallon) [(b)] | 0.79 | 0.56 | 0.23 | 41% | 0.69 | 0.53 | 0.16 | 30% |

(a) Based on weighted average of bid week prompt month prices on the New York Mercantile Exchange ("NYMEX").
(b) Based on our estimated NGLs product composition per barrel.

Our price realizations may differ from the benchmarks for many reasons, including quality, location or production being sold at different indices.

### Consolidated Results of Operations

#### *Overview of Third Quarter 2018 Results*

Our financial results are significantly impacted by commodity prices. For third quarter 2018, we experienced an increase in revenue from the sale of natural gas, NGLs and oil due to a 4% increase in net realized prices (average prices including all derivative settlements and third party transportation costs paid by us) and 14% higher production volumes when compared to the same quarter of

2017. Daily production in third quarter 2018 averaged 2.3 Bcfe compared to 2.0 Bcfe in the same period of the prior year with the increase due to our successful Marcellus horizontal drilling program. Average natural gas differentials improved $0.39 per mcf while operating costs were lower when compared to the same period of 2017.

During third quarter 2018, we recognized net income of $48.5 million, or $0.19 per diluted common share compared to a net loss of $127.7 million, or $0.52 per diluted common share, during third quarter 2017. The increase in net income for third quarter 2018 from third quarter 2017 is primarily due to favorable derivative fair value income (or the non-cash fair value adjustments related to our derivatives), higher production volumes and realized prices along with lower proved and unproved property impairment charges.

Our third quarter 2018 financial and operating performance included the following results:

- 14% production growth over the same period of 2017;
- revenue from the sale of natural gas, NGLs and oil increased 45% from the same period of 2017 with a 27% increase in average realized prices (before cash settlements on our derivatives) and an increase in production volumes;
- revenue from the sale of natural gas, NGLs and oil (including cash settlements on our derivatives) increased 34% from the same period of 2017;
- reduced direct operating expenses per mcfe 25% from the same period of 2017 (see discussion on page 38);
- reduced general and administrative expense per mcfe 28% from the same period of 2017 (see discussion on page 38);
- reduced interest expense per mcfe 4% from the same period of 2017;
- reduced our depletion, depreciation and amortization (“DD&A”) rate per mcfe by 9% from the same period of 2017;
- entered into additional derivative contracts for 2018, 2019, 2020 and 2021;
- reduced our bank credit facility $48.0 million from June 2018; and
- realized $229.4 million of cash flow from operating activities.

We generated $229.4 million of cash flow from operating activities in third quarter 2018, an increase of $40.2 million from third quarter 2017, which reflects improvements in realized prices and higher production volumes somewhat offset by higher comparative working capital outflows ($22.9 million outflow during third quarter 2018 compared to $4.4 million inflow in third quarter 2017).

### *Overview of First Nine Months 2018 Results*

For first nine months 2018, we experienced an increase in revenue from the sale of natural gas, NGLs and oil due to a 6% increase in net realized prices (average prices including all derivative settlements and third party transportation costs paid by us) and 14% higher production volumes when compared to the same period of 2017. Daily production in first nine months 2018 averaged 2.2 Bcfe compared to 2.0 Bcfe in the same period of the prior year as a result of drilling and completions in Pennsylvania. Average natural gas differentials improved $0.30 per mcf while operating costs were higher when compared to the same period of 2017.

During first nine months 2018, we recognized net income of $17.9 million, or $0.07 per diluted common share compared to net income of $112.0 million, or $0.45 per diluted common share during the same period of 2017. The decrease in net income for first nine months 2018 from the same period of 2017 is primarily due to lower derivative fair value income or the non-cash fair value adjustments related to our derivatives somewhat offset by higher production volumes and realized prices and lower proved property impairment charges.

Our first nine months financial and operating performance included the following results:

- 14% production growth over the same period of 2017;
- liquids production represented 32% of total production on an mcfe basis compared to 33% in the same period of 2017;
- revenue from the sale of natural gas, NGLs and oil increased 33% from the same period of 2017 with a 17% increase in average realized prices (before cash settlements on our derivatives) and an increase in production volumes;
- revenue realized from the sale of natural gas, NGLs and oil (including cash settlements on our derivatives) increased 29% from the same period of 2017;
- trends in forward commodity prices compared to the prior year resulted in downward non-cash derivative fair value adjustments of $283.9 million;
- decreased direct operating expenses per mcfe by 6% from the same period of 2017 (see discussion on page 38);
- decreased general and administrative expense per mcfe 10% from the same period of 2017 (see discussion on page 38);
- interest expense per mcfe was the same when compared to the same period of 2017;
- reduced our DD&A rate per mcfe by 8% from the same period of 2017;
- entered into additional derivative contracts for 2018, 2019, 2020 and 2021; and
- realized $774.9 million of cash flow from operating activities.

We generated $774.9 million of cash flow from operating activities in first nine months 2018, an increase of $174.4 million from the same period of 2017 which reflects improvements in realized prices and higher production volumes somewhat offset by higher comparative working capital outflows ($20.3 million outflow during first nine months 2018 compared to $10.0 million outflow in the same period of 2017). We ended the quarter with $452.6 million of available committed borrowing capacity, with an additional $1.0 billion in borrowing base capacity.

**Adoption of New Accounting Standard**

On January 1, 2018, we adopted the new revenue recognition accounting standards update. As a result of this adoption, we have modified our presentation of certain gas processing contracts. Results for reporting periods beginning after January 1, 2018 are presented based on the new accounting standards while prior period amounts are not adjusted and continue to be reported in accordance with our historical accounting. For additional information, see Note 3 and Note 5 to the consolidated financial statements. The impact of adoption of the new revenue recognition standard on the three and nine month period ended September 30, 2018 is as follows (in thousands):

| | Three Months Ended September 30, 2018 | | Nine Months Ended September 30, 2018 | |
|---|---|---|---|---|
| | As Reported | Previous Revenue Recognition Method | As Reported | Previous Revenue Recognition Method |
| **Natural gas, NGLs and oil sales** | | | | |
| Natural gas | $ 390,656 | $ 390,656 | $ 1,182,580 | $ 1,182,580 |
| NGLs | 278,563 | 230,816 | 705,793 | 578,074 |
| Oil | 67,212 | 67,212 | 206,077 | 206,077 |
| Total | $ 736,431 | $ 688,684 | $ 2,094,450 | $ 1,966,731 |
| **Transportation, gathering, processing and compression** | | | | |
| Natural gas | $ 176,271 | $ 176,271 | $ 497,569 | $ 497,569 |
| NGLs | 128,291 | 80,544 | 321,531 | 193,812 |
| Total | $ 304,562 | $ 256,815 | $ 819,100 | $ 691,381 |
| **Net income** | $ 48,539 | $ 48,539 | $ 17,941 | $ 17,941 |

See Note 3 for a discussion of new accounting standards that affect us.

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

Our revenues vary primarily as a result of changes in realized commodity prices and production volumes. Our revenues are generally recognized at the point in time that control of the product is transferred to the customer and collectability is reasonably assured.

In third quarter 2018, natural gas, NGLs and oil sales increased 45% compared to third quarter 2017 with a 27% increase in average realized prices (before cash settlements on our derivatives) and a 14% increase in average daily production. In first nine months 2018, natural gas, NGLs and oil sales increased 33% compared to the same period of 2017 with a 17% increase in average realized prices (before cash settlements on our derivatives) and a 14% increase in production. NGLs sales for the current year includes the impact of the adoption of the new revenue recognition standard, as described above. The following table illustrates the primary components of natural gas, NGLs, oil and condensate sales for the three months and nine months ended September 30, 2018 and 2017 (in thousands):

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2018 | 2017 | Change | % | 2018 | 2017 | Change | % |
| **Natural gas, NGLs and oil sales** | | | | | | | | |
| Natural gas | $ 390,656 | $ 301,114 | $ 89,542 | 30% | $ 1,182,580 | $ 1,009,000 | $ 173,580 | 17% |
| NGLs | 278,563 | 150,593 | 127,970 | 85% | 705,793 | 412,440 | 293,353 | 71% |
| Oil | 67,212 | 55,834 | 11,378 | 20% | 206,077 | 151,688 | 54,389 | 36% |
| Total natural gas, NGLs and oil sales | $ 736,431 | $ 507,541 | $ 228,890 | 45% | $ 2,094,450 | $ 1,573,128 | $ 521,322 | 33% |

Our production continues to grow through drilling success and additional NGLs extraction, which is partially offset by the natural production decline of our wells and non-core asset sales. Third quarter 2018 production volumes from the Marcellus Shale were 2.0 Bcfe per day, an increase of 25% when compared to the same period of 2017. Third quarter 2018 production volumes from our North Louisiana properties were approximately 278.0 Mmcfe per day. When compared to the same period of 2017, our North Louisiana production volumes declined 23%.

Production volumes from the Marcellus Shale in first nine months 2018 were 1.9 Bcfe per day. When compared to the same period of 2017, our Marcellus production volumes increased 24% for first nine months 2018. In first nine months 2018, production volumes from our North Louisiana properties were approximately 318.9 Mmcfe per day. When compared to the same period of 2017, our North Louisiana production volumes decreased 18%. Our production for the three months and nine months ended September 30, 2018 and 2017 is set forth in the following table:

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2018 | 2017 | Change | % | 2018 | 2017 | Change | % |
| **Production** (a) | | | | | | | | |
| Natural gas (mcf) | 140,757,676 | 121,644,949 | 19,112,727 | 16% | 411,769,576 | 357,389,113 | 54,380,463 | 15% |
| NGLs (bbls) | 10,255,159 | 8,892,778 | 1,362,381 | 15% | 29,009,100 | 25,953,773 | 3,055,327 | 12% |
| Crude oil (bbls) | 1,040,891 | 1,288,303 | (247,412) | (19%) | 3,314,704 | 3,406,373 | (91,669) | (3%) |
| Total (mcfe) (b) | 208,533,976 | 182,731,435 | 25,802,541 | 14% | 605,712,400 | 533,549,989 | 72,162,411 | 14% |
| **Average daily production** (a) | | | | | | | | |
| Natural gas (mcf) | 1,529,975 | 1,322,228 | 207,747 | 16% | 1,508,313 | 1,309,118 | 199,195 | 15% |
| NGLs (bbls) | 111,469 | 96,661 | 14,808 | 15% | 106,260 | 95,069 | 11,191 | 12% |
| Crude oil (bbls) | 11,314 | 14,003 | (2,689) | (19%) | 12,142 | 12,478 | (336) | (3%) |
| Total (mcfe) (b) | 2,266,674 | 1,986,211 | 280,463 | 14% | 2,218,727 | 1,954,396 | 264,331 | 14% |

(a) Represents volumes sold regardless of when produced.

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

Our average realized price received (including all derivative settlements and third-party transportation costs) during third quarter 2018 was $1.90 per mcfe compared to $1.82 per mcfe in third quarter 2017. Our average realized price received (including all derivative settlements and third party transportation costs) was $2.04 per mcfe in first nine months 2018 compared to $1.93 per mcfe in the same period of the prior year. We believe computed final realized prices should include the total impact of transportation, gathering, processing and compression expense. Our average realized price (including all derivative settlements and third-party transportation costs) calculation also includes all cash settlements for derivatives. Average realized prices (excluding derivative settlements) do not include derivative settlements or third party transportation costs which are reported in transportation, gathering, processing and compression expense on the accompanying consolidated statements of operations. Average realized prices (excluding derivative settlements) do include transportation costs where we receive net revenue proceeds from purchasers.

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2018 | 2017 | Change | % | 2018 | 2017 | Change | % |
| **Average Prices** | | | | | | | | |
| Average realized prices (excluding derivative settlements): | | | | | | | | |
| Natural gas (per mcf) | $ 2.78 | $ 2.48 | $ 0.30 | 12% | $ 2.87 | $ 2.82 | $ 0.05 | 2% |
| NGLs (per bbl) | 27.16 | 16.93 | 10.23 | 60% | 24.33 | 15.89 | 8.44 | 53% |
| Crude oil and condensate (per bbl) | 64.57 | 43.34 | 21.23 | 49% | 62.17 | 44.53 | 17.64 | 40% |
| Total (per mcfe) (a) | 3.53 | 2.78 | 0.75 | 27% | 3.46 | 2.95 | 0.51 | 17% |
| Average realized prices (including all derivative settlements): | | | | | | | | |
| Natural gas (per mcf) | $ 2.82 | $ 2.69 | $ 0.13 | 5% | $ 3.01 | $ 2.92 | $ 0.09 | 3% |
| NGLs (per bbl) | 24.43 | 15.14 | 9.29 | 61% | 22.14 | 14.60 | 7.54 | 52% |
| Crude oil and condensate (per bbl) | 52.33 | 48.46 | 3.87 | 8% | 52.12 | 48.90 | 3.22 | 7% |
| Total (per mcfe) (a) | 3.36 | 2.87 | 0.49 | 17% | 3.39 | 2.98 | 0.41 | 14% |
| Average realized prices (including all derivative settlements and third party transportation costs paid by Range): | | | | | | | | |
| Natural gas (per mcf) | $ 1.56 | $ 1.60 | $ (0.04) | (2%) | $ 1.80 | $ 1.84 | $ (0.04) | (2%) |
| NGLs (per bbl) | 11.92 | 8.54 | 3.38 | 40% | 11.06 | 7.82 | 3.24 | 41% |
| Crude oil and condensate (per bbl) | 52.33 | 48.46 | 3.87 | 8% | 52.12 | 48.90 | 3.22 | 7% |
| Total (per mcfe) (a) | 1.90 | 1.82 | 0.08 | 4% | 2.04 | 1.93 | 0.11 | 6% |

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

Realized prices include the impact of basis differentials and gains or losses realized from our basis hedging. The prices we receive for our natural gas can be more or less than the NYMEX price because of adjustments for delivery location, relative quality and other factors. The following table provides this impact on a per mcf basis:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Average natural gas differentials above or (below) NYMEX | $ (0.13) | $ (0.52) | $ (0.03) | $ (0.33) |
| Realized (losses) gains on basis hedging | $ (0.02) | $ 0.01 | $ (0.03) | $ 0.03 |

The following tables reflect our production and average realized commodity prices (excluding derivative settlements and third party transportation costs paid by Range) (in thousands, except prices):

| | Three Months Ended September 30 | | | | Nine Months Ended September 30 | | | |
|---|---|---|---|---|---|---|---|---|
| | 2017 | Price Variance | Volume Variance | 2018 | 2017 | Price Variance | Volume Variance | 2018 |
| **Natural gas** | | | | | | | | |
| Price (per mcf) | $ 2.48 | $ 0.30 | $ — | $ 2.78 | $ 2.82 | $ 0.05 | $ — | $ 2.87 |
| Production (Mmcf) | 121,645 | — | 19,113 | 140,758 | 357,389 | — | 54,381 | 411,770 |
| **Natural gas sales** | $ 301,114 | $ 42,231 | $ 47,311 | $ 390,656 | $ 1,009,000 | $ 20,050 | $ 153,530 | $ 1,182,580 |

| | Three Months Ended September 30 | | | | Nine Months Ended September 30 | | | |
|---|---|---|---|---|---|---|---|---|
| | 2017 | Price Variance | Volume Variance | 2018 | 2017 | Price Variance | Volume Variance | 2018 |
| **NGLs** | | | | | | | | |
| Price (per bbl) | $ 16.93 | $ 10.23 | $ — | $ 27.16 | $ 15.89 | $ 8.44 | $ — | $ 24.33 |
| Production (Mbbls) | 8,893 | — | 1,362 | 10,255 | 25,954 | — | 3,055 | 29,009 |
| **NGLs sales** | $ 150,593 | $ 104,899 | $ 23,071 | $ 278,563 | $ 412,440 | $ 244,800 | $ 48,553 | $ 705,793 |

| | Three Months Ended September 30 | | | | Nine Months Ended September 30 | | | |
|---|---|---|---|---|---|---|---|---|
| | 2017 | Price Variance | Volume Variance | 2018 | 2017 | Price Variance | Volume Variance | 2018 |
| **Crude oil** | | | | | | | | |
| Price (per bbl) | $ 43.34 | $ 21.23 | $ — | $ 64.57 | $ 44.53 | $ 17.64 | $ — | $ 62.17 |
| Production (Mbbls) | 1,288 | — | (247) | 1,041 | 3,406 | — | (91) | 3,315 |
| **Crude oil sales** | $ 55,834 | $ 22,100 | $ (10,722) | $ 67,212 | $ 151,688 | $ 58,471 | $ (4,082) | $ 206,077 |

| | Three Months Ended September 30 | | | | Nine Months Ended September 30 | | | |
|---|---|---|---|---|---|---|---|---|
| | 2017 | Price Variance | Volume Variance | 2018 | 2017 | Price Variance | Volume Variance | 2018 |
| **Consolidated** | | | | | | | | |
| Price (per mcfe) | $ 2.78 | $ 0.75 | $ — | $ 3.53 | $ 2.95 | $ 0.51 | $ — | $ 3.46 |
| Production (Mmcfe) | 182,731 | — | 25,803 | 208,534 | 533,550 | — | 72,162 | 605,712 |
| **Total natural gas, NGLs and oil sales** | $ 507,541 | $ 157,223 | $ 71,667 | $ 736,431 | $ 1,573,128 | $ 308,557 | $ 212,765 | $ 2,094,450 |

**Transportation, gathering, processing and compression** expense was $304.6 million in third quarter 2018 compared to $191.6 million in third quarter 2017. These third-party costs are higher in 2018 when compared to 2017 due to our production growth in the Marcellus Shale where we have third-party transportation, gathering, processing and compression agreements. Additionally, we experienced higher costs resulting from our adoption of the new revenue standard, new in-service pipelines, higher NGLs costs due to higher production and prices and higher NGLs expense in North Louisiana due to fully utilizing amounts that were previously accrued for capacity commitments. We have included these costs in the calculation of average realized prices (including all derivative settlements and third-party transportation expenses paid by Range).

Transportation, gathering processing and compression was $819.1 million in first nine months 2018 compared to $560.9 million in first nine months 2017. These third-party costs are higher in 2018 when compared to 2017 due to new in-service pipelines, higher Marcellus production volumes, higher NGLs expense in North Louisiana due to fully utilizing amounts that were previously accrued for capacity commitments and the impact of our adoption of the new revenue recognition accounting standard. For additional information, see Adoption of New Accounting Standard above. 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 the three months and nine months ended September 30, 2018 and 2017 (in thousands) and on a per mcf and per barrel basis:

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2018 | 2017 | Change | % | 2018 | 2017 | Change | % |
| Natural gas | $ 176,271 | $ 133,019 | $ 43,252 | 33% | $ 497,569 | $ 384,769 | $ 112,800 | 29% |
| NGLs | 128,291 | 58,626 | 69,665 | 119% | 321,531 | 176,114 | 145,417 | 83% |
| Total | $ 304,562 | $ 191,645 | $ 112,917 | 59% | $ 819,100 | $ 560,883 | $ 258,217 | 46% |
| | | | | | | | | |
| Natural gas (per mcf) | $ 1.25 | $ 1.09 | $ 0.16 | 15% | $ 1.21 | $ 1.08 | $ 0.13 | 12% |
| NGLs (per bbl) | $ 12.51 | $ 6.59 | $ 5.92 | 90% | $ 11.08 | $ 6.79 | $ 4.29 | 63% |

**Derivative fair value (loss) income** was a loss of $34.6 million in third quarter 2018 compared to a loss of $88.4 million in third quarter 2017. Derivative fair value (loss) income was a loss of $151.9 million in first nine months 2018 compared to a gain of $188.3 million in the same period of 2017. All of our derivatives are accounted for using the mark-to-market accounting method. Mark-to-market accounting treatment can result in more volatility of our revenues as the change in the fair value of our commodity derivative positions is included in total revenue. As commodity prices increase or decrease, such changes will have an opposite effect on the mark-to-market value of our derivatives. Gains on our derivatives generally indicate potentially lower wellhead revenues in the future while losses indicate potentially higher future wellhead revenues. The following table summarizes the impact of our commodity derivatives for the three months and nine months ended September 30, 2018 and 2017 (in thousands):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Derivative fair value (loss) income per consolidated statements of operations | $ (34,591) | $ (88,426) | $ (151,890) | $ 188,326 |
| Non-cash fair value gain (loss): (1) | | | | |
| Natural gas derivatives | $ 3,326 | $ (16,409) | $ (89,556) | $ 155,827 |
| Oil derivatives | (5,659) | (18,991) | (33,416) | 9,951 |
| NGLs derivatives | 2,529 | (69,820) | 11,329 | 6,505 |
| Freight derivatives | 135 | (63) | 25 | (19) |
| Total non-cash fair value gain (loss) (1) | $ 331 | $ (105,283) | $ (111,618) | $ 172,264 |
| Net cash (payment) receipt on derivative settlements: | | | | |
| Natural gas derivatives | $ 5,845 | $ 26,250 | $ 56,466 | $ 34,647 |
| Oil derivatives | (12,744) | 6,602 | (33,303) | 14,874 |
| NGL derivatives | (28,023) | (15,995) | (63,435) | (33,459) |
| Total net cash (payment) receipt | $ (34,922) | $ 16,857 | $ (40,272) | $ 16,062 |

(1) Non-cash fair value adjustments on commodity derivatives is a non-U.S. 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 U.S. 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 in third quarter 2018 was $109.4 million compared to $63.1 million in third quarter 2017 with significantly higher brokered sales volumes and prices. Brokered natural gas marketing and other revenue in first nine months 2018 was $267.4 million compared to $170.5 million in the same period of the prior year due to significantly higher brokered sales volumes.

**Operating Costs 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 the three months and nine months ended September 30, 2018 and 2017:

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2018 | 2017 | Change | % | 2018 | 2017 | Change | % |
| Direct operating expense | $ 0.15 | $ 0.20 | $ (0.05) | (25%) | $ 0.17 | $ 0.18 | $ (0.01) | (6%) |
| Production and ad valorem tax expense | 0.05 | 0.07 | (0.02) | (29%) | 0.05 | 0.06 | (0.01) | (17%) |
| General and administrative expense | 0.21 | 0.29 | (0.08) | (28%) | 0.26 | 0.29 | (0.03) | (10%) |
| Interest expense | 0.26 | 0.27 | (0.01) | (4%) | 0.27 | 0.27 | — | —% |
| Depletion, depreciation and amortization expense | 0.79 | 0.87 | (0.08) | (9%) | 0.80 | 0.87 | (0.07) | (8%) |

**Direct operating** expense was $30.9 million in third quarter 2018 compared to $36.9 million in third quarter 2017. Direct operating expenses include normally recurring expenses to operate and produce our wells, non-recurring well workovers and repair-related expenses. Our direct operating costs decreased in third quarter 2018 primarily due to lower utilities, lower workover costs and the sale of our Northern Oklahoma properties. Our production volumes increased 14% in third quarter 2018. We incurred $1.4 million ($0.01 per mcfe) of workover costs in third quarter 2018 compared to $3.5 million ($0.02 per mcfe) in third quarter 2017. On a per mcfe basis, direct operating expense in third quarter 2018 decreased 25% to $0.15 from $0.20 in the same period of 2017 with the decrease resulting from lower workovers, lower utility costs, lower overhead costs and the sale of our Northern Oklahoma properties.

Direct operating expense was $104.1 million in first nine months 2018 compared to $96.3 million in the same period of 2017. Our direct operating costs increased in first nine months 2018 compared to the same period of 2017 due to higher water hauling/handling costs and higher contract pumping costs. Our production volumes increased 14% in first nine months 2018. We incurred $6.3 million of workover costs in first nine months 2018 compared to $6.9 million in the same period of 2017. On a per mcfe basis, direct operating expense in first nine months 2018 decreased 6% to $0.17 from $0.18 in the same period of 2017 with the decrease resulting from lower utility costs. The following table summarizes direct operating expenses per mcfe for the three months and the nine months ended September 30, 2018 and 2017:

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2018 | 2017 | Change | % | 2018 | 2017 | Change | % |
| Lease operating expense | $ 0.14 | $ 0.18 | $ (0.04) | (22%) | $ 0.16 | $ 0.17 | $ (0.01) | (6%) |
| Workovers | 0.01 | 0.02 | (0.01) | (50%) | 0.01 | 0.01 | — | —% |
| Stock-based compensation (non-cash) | — | — | — | —% | — | — | — | —% |
| Total direct operating expense | $ 0.15 | $ 0.20 | $ (0.05) | (25%) | $ 0.17 | $ 0.18 | $ (0.01) | (6%) |

**Production and ad valorem taxes** are paid based on market prices rather than hedged prices. This expense category also includes the Pennsylvania impact fee. Production and ad valorem taxes (excluding the impact fee) were $3.4 million in third quarter 2018 compared to $4.1 million in third quarter 2017 due to increase in volumes not subject to production taxes. In February 2012, the Commonwealth of Pennsylvania enacted an “impact fee” which functions as a tax on unconventional natural gas and oil production from the Marcellus Shale in Pennsylvania. Included in third quarter 2018 is a $6.1 million impact fee compared to $7.9 million in third quarter 2017. Production and ad valorem taxes (excluding the impact fee) were $10.5 million in first nine months 2018 compared to $8.4 million in the same period of 2017 due to higher commodity prices and higher volumes subject to production taxes. Included in first nine months 2018 is $19.0 million impact fee compared to $22.7 million in the same period 2017. The following table summarizes production and ad valorem taxes per mcfe for the three months and the nine months ended September 30, 2018 and 2017:

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2018 | 2017 | Change | % | 2018 | 2017 | Change | % |
| Production taxes | $ 0.01 | $ 0.02 | $ (0.01) | (50%) | $ 0.01 | $ 0.01 | $ — | —% |
| Ad valorem taxes | 0.01 | 0.01 | — | —% | 0.01 | 0.01 | — | —% |
| Impact fee | 0.03 | 0.04 | (0.01) | (25%) | 0.03 | 0.04 | (0.01) | (25%) |
| Total production and ad valorem taxes | $ 0.05 | $ 0.07 | $ (0.02) | (29%) | $ 0.05 | $ 0.06 | $ (0.01) | (17%) |

**General and administrative** (“G&A”) expense was $43.7 million in third quarter 2018 compared to $53.0 million in third quarter 2017. The third quarter 2018 decrease of $9.3 million when compared to the same period of 2017 is primarily due to lower stock-based compensation of $4.4 million and lower legal settlements partially offset by higher technology and legal costs. At September 30, 2018, the number of G&A employees increased 6% when compared to September 30, 2017. On a per mcfe basis, third quarter 2018 G&A expense decreased 28% from third quarter 2017 due to lower stock-based compensation costs and lower legal settlements and the impact of higher production volumes.

G&A expense for first nine months 2018 increased by $6.9 million when compared to the same period of the prior year due to higher stock-based compensation costs of $3.2 million, higher severance costs, higher land and legal consulting costs and higher technology costs. The higher stock-based compensation costs are related to those officers that qualified for the postretirement plan implemented in fourth quarter 2017 and therefore also qualified for accelerated vesting of equity grants. In addition, the timing of senior executive equity grants was moved from May to March in 2018 to better align with our proxy statement filings. On a per mcfe basis, G&A expense for first nine months 2018 decreased 10% from first nine months 2017 due to the impact of higher production volumes. The following table summarizes G&A expenses per mcfe for the three months and nine months ended September 30, 2018 and 2017:

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2018 | 2017 | Change | % | 2018 | 2017 | Change | % |
| General and administrative | $ 0.18 | $ 0.24 | $ (0.06) | (25%) | $ 0.20 | $ 0.22 | $ (0.02) | (9%) |
| Stock-based compensation (non-cash) | 0.03 | 0.05 | (0.02) | (40%) | 0.06 | 0.07 | (0.01) | (14%) |
| Total general and administrative expense | $ 0.21 | $ 0.29 | $ (0.08) | (28%) | $ 0.26 | $ 0.29 | $ (0.03) | (10%) |

**Interest expense** was $54.8 million in third quarter 2018 compared to $49.2 million in third quarter 2017. Interest expense was $161.0 million for nine months 2018 compared to $144.2 million in the same period of 2017. The following table presents information about interest expense per mcfe for the three months and nine months ended September 30, 2018 and 2017:

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2018 | 2017 | Change | % | 2018 | 2017 | Change | % |
| Bank credit facility | $ 0.07 | $ 0.05 | $ 0.02 | 40% | $ 0.07 | $ 0.05 | $ 0.02 | 40% |
| Senior notes | 0.18 | 0.20 | (0.02) | (10%) | 0.19 | 0.21 | (0.02) | (10%) |
| Subordinated notes | — | — | — | —% | — | — | — | —% |
| Amortization of deferred financing costs and other | 0.01 | 0.02 | (0.01) | (50%) | 0.01 | 0.01 | — | —% |
| Total interest expense | $ 0.26 | $ 0.27 | $ (0.01) | (4%) | $ 0.27 | $ 0.27 | $ — | —% |
| | | | | | | | | |
| Average debt outstanding (in thousands) | $ 4,279,958 | $ 4,003,045 | $ 276,913 | 7% | $ 4,249,437 | $ 3,915,044 | $ 334,393 | 9% |
| Average interest rate [(a)] | 5.0% | 4.7% | 0.3% | 6% | 4.9% | 4.7% | 0.2% | 4% |

(a) Includes commitment fees but excludes debt issue costs and amortization of discounts.

On an absolute basis, the increase in interest expense for third quarter 2018 from the same period of 2017 was primarily due to higher average outstanding debt balances and slightly higher average interest rates. Average debt outstanding on the bank credit facility for third quarter 2018 was $1.4 billion compared to $1.1 billion in third quarter 2017 and the weighted average interest rate on the bank credit facility was 3.9% in third quarter 2018 compared to 2.8% in third quarter 2017.

On an absolute basis, the increase in interest expense for first nine months 2018 from the same period of 2017 was primarily due to higher average outstanding debt balances and slightly higher average interest rates. Average debt outstanding on the bank credit facility was $1.3 billion for first nine months 2018 compared to $989.0 million for the same period of 2017 and the weighted average interest rate on the bank credit facility was 3.7% in first nine months 2018 compared to 2.6% in first nine months 2017.

**Depletion, depreciation and amortization** expense was $164.3 million in third quarter 2018 compared to $159.7 million in third quarter 2017. This increase is due to a 14% increase in production volumes somewhat offset by a 10% decrease in depletion rates. Depletion expense, the largest component of DD&A expense, was $0.76 per mcfe in third quarter 2018 compared to $0.84 per mcfe in third quarter 2017. We have historically 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. Our depletion rate per mcfe continues to decline due to the mix of production from our properties with lower depletion rates and asset sales.

DD&A expense was $487.6 million in first nine months 2018 compared to $462.1 million in the same period of 2017. This is due to a 14% increase in production volumes somewhat offset by a 7% decrease in depletion rates. Depletion expense was $0.78 per mcfe in first nine months 2018 compared to $0.84 in the same period of 2017. The following table summarizes DD&A expense per mcfe for the three months and nine months ended September 30, 2018 and 2017:

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2018 | 2017 | Change | % | 2018 | 2017 | Change | % |
| Depletion and amortization | $ 0.76 | $ 0.84 | $ (0.08) | (10%) | $ 0.78 | $ 0.84 | $ (0.06) | (7%) |
| Depreciation | 0.01 | 0.01 | — | —% | — | 0.01 | (0.01) | (100%) |
| Accretion and other | 0.02 | 0.02 | — | —% | 0.02 | 0.02 | — | —% |
| Total DD&A expense | $ 0.79 | $ 0.87 | $ (0.08) | (9%) | $ 0.80 | $ 0.87 | $ (0.07) | (8%) |

### *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 expense, exploration expense, abandonment and impairment of unproved properties, termination costs, deferred compensation plan expenses, impairment of proved properties and gain or loss on sale of assets. Stock-based compensation includes the amortization of restricted stock grants and PSUs. The following table details the allocation of stock-based compensation to functional expense categories for the three months and nine months ended September 30, 2018 and 2017 (in thousands):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Direct operating expense | $ 537 | $ 517 | $ 1,667 | $ 1,563 |
| Brokered natural gas and marketing expense | 403 | 389 | 1,001 | 1,040 |
| Exploration expense | 405 | 561 | 1,527 | 1,596 |
| General and administrative expense | 5,607 | 9,959 | 38,332 | 35,156 |
| Termination costs | — | (31) | — | 1,665 |
| Total stock-based compensation | $ 6,952 | $ 11,395 | $ 42,527 | $ 41,020 |

**Brokered natural gas and marketing** expense was $116.1 million in third quarter 2018 compared to $59.8 million in third quarter 2017. The increase reflects significantly higher broker purchase volumes, purchase prices and transportation costs. Brokered natural gas and marketing expense was $274.4 million for first nine months 2018 compared to $169.2 million in the same period of 2017. This increase reflects significantly higher broker purchase volumes and higher transportation costs. The following table details our brokered natural gas, marketing and other net margin for the three months and nine months ended September 30, 2018 and 2017 (in thousands):

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2018 | 2017 | Change | % | 2018 | 2017 | Change | % |
| Brokered natural gas sales | $ 105,840 | $ 57,292 | $ 48,548 | 85% | $ 255,134 | $ 156,899 | $ 98,235 | 63% |
| Brokered NGL sales | (153) | — | (153) | —% | 880 | 728 | 152 | (21%) |
| Other marketing revenue | 3,698 | 5,825 | (2,127) | (37%) | 11,434 | 12,917 | (1,483) | (11%) |
| Brokered natural gas purchases | (113,886) | (57,387) | (56,499) | 98% | (265,817) | (161,741) | (104,076) | 64% |
| Brokered NGL purchases | 165 | — | 165 | —% | (776) | (601) | (175) | 29% |
| Other marketing expense | (2,359) | (2,386) | 27 | (1%) | (7,828) | (6,838) | (990) | 14% |
| Net brokered natural gas and marketing net margin | $ (6,695) | $ 3,344 | $ (10,039) | (300%) | $ (6,973) | $ 1,364 | $ (8,337) | (611%) |

**Exploration** expense was $8.3 million in third quarter 2018 compared to $22.8 million in third quarter 2017 due to lower seismic and dry hole costs. Exploration expense was $23.5 million in first nine months 2018 compared to $45.8 million in the same period of 2017 due to lower seismic and dry hole costs. The following table details our exploration expense for the three months and nine months ended September 30, 2018 and 2017 (in thousands):

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2018 | 2017 | Change | % | 2018 | 2017 | Change | % |
| Seismic | $ 152 | $ 5,143 | $ (4,991) | (97%) | $ 92 | $ 14,096 | $ (14,004) | (99%) |
| Delay rentals and other | 5,657 | 5,333 | 324 | 6% | 13,764 | 11,910 | 1,854 | 16% |
| Personnel expense | 2,083 | 2,725 | (642) | (24%) | 8,130 | 9,001 | (871) | (10%) |
| Dry hole expense | 2 | 9,005 | (9,003) | (100%) | 4 | 9,166 | (9,162) | (100%) |
| Stock-based compensation expense | 405 | 561 | (156) | (28%) | 1,527 | 1,596 | (69) | (4%) |
| Total exploration expense | $ 8,299 | $ 22,767 | $ (14,468) | (64%) | $ 23,517 | $ 45,769 | $ (22,252) | (49%) |

**Abandonment and impairment of unproved properties** was $6.5 million in third quarter 2018 compared to $42.6 million in third quarter 2017. Abandonment and impairment of unproved properties was $73.2 million in first nine months 2018 compared to $52.2 million in the same period of 2017. 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. In certain circumstances, our future plans to develop acreage may accelerate our impairment. The decrease in abandonment expense in third quarter 2018 compared to the same period of 2017 reflects fewer North Louisiana lease expirations. The increase in abandonment expense in the nine month period of 2018 from 2017 reflects an increase in 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 may be recorded.

**Termination costs** were a reduction of $336,000 in third quarter 2018 compared to a reduction of $47,000 in third quarter 2017. Termination costs were a reduction of $373,000 in first nine months 2018 compared to $4.0 million of expense in first nine months 2017. In first quarter 2017, we implemented additional work force reductions which increased these costs to $2.4 million for estimated severance costs and $1.7 million of accelerated vesting of equity grants.

**Deferred compensation plan** expense was a loss of $223,000 in third quarter 2018 compared to a gain of $9.2 million in third quarter 2017. This non-cash item relates to the increase or decrease in value of the liability associated with our common stock that is vested and held in our deferred compensation plan. The deferred compensation liability is adjusted to fair value by a charge or a credit to deferred compensation plan expense. Our stock price increased from $16.73 at June 30, 2018 to $16.99 at September 30, 2018. In the same period of the prior year, our stock price decreased from $23.17 at June 30, 2017 to $19.57 at September 30, 2017. During first nine months ended 2018, deferred compensation was a gain of $559,000 compared to a gain of $36.8 million in the same period of 2017. Our stock price decreased from $17.06 at December 31, 2017 to $16.99 at September 30, 2018. In the same period of 2017, our stock price decreased from $34.36 at December 31, 2016 to $19.57 at September 30, 2017.

**Impairment of proved properties** was $15.3 million in second quarter 2018 and $7.3 million in first quarter 2018. In second quarter 2018, we recorded impairment expense related to certain properties in Northwest Pennsylvania and in first quarter 2018, we recorded impairment expense related to certain of our oil and gas properties in Oklahoma. These Oklahoma assets were evaluated for impairment due to the possibility of sale. There were no proved property impairments in third quarter 2018. Impairment of proved properties was $63.7 million in both third quarter and first nine months 2017 related to certain oil and gas properties in Oklahoma and the Texas Panhandle where we determined that undiscounted future cash flows were less than their carrying amounts. Our analysis also included the possibility of a sale of these properties.

**Loss (gain) on the sale of assets** was a loss of $30,000 in third quarter 2018 compared to a gain of $102,000 in third quarter 2017. In first nine months 2018, gain on sale of assets was $149,000 compared to a gain of $23.5 million in the same period of 2017. In the third quarter and first nine months 2018, we sold properties in Northern Oklahoma for $23.3 million of proceeds and, after closing adjustments, we recognized a loss of $39,000. In first quarter and first nine months 2017, we sold properties in Western Oklahoma for $26.0 million of proceeds and, after closing adjustments, we recognized a gain of $22.1 million related to this sale.

**Income tax expense (benefit)** was an expense of $24.1 million in third quarter 2018 compared to benefit of $72.0 million in third quarter 2017. For third quarter 2018, the effective tax rate was 33.2% compared to 36.1% in 2017. Income tax expense was $38.3 million in first nine months 2018 compared to $98.1 million in the same period of 2017. For first nine months 2018, the effective tax rate was 68.1% compared to 46.7% in first nine months 2017. The 2018 and 2017 effective tax rates were different than the statutory tax rate due to state income taxes (including adjustments to state income tax valuation allowances), equity compensation and other discrete tax items which are detailed below. We expect our effective tax rate to be approximately 24% for the remainder of 2018, before any discrete tax items (dollars in thousands).

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 |
| Total income (loss) before income taxes | $ 72,676 | $ (199,692) | $ 56,236 | $ 210,015 |
| U.S. federal statutory rate | 21% | 35% | 21% | 35% |
| Total tax expense (benefit) at statutory rate | 15,262 | (69,892) | 11,810 | 73,505 |
| State and local income taxes, net of federal benefit | 2,691 | (6,537) | 3,439 | 6,591 |
| Non-deductible executive compensation | 48 | 296 | 601 | 436 |
| Equity compensation | 6 | 56 | 2,146 | 4,808 |
| Change in valuation allowances: | | | | |
| Federal net operating loss carryforwards & other | — | 69 | — | 3,487 |
| State net operating loss carryforwards & other | 5,558 | 4,286 | 19,194 | 10,498 |
| Rabbi trust and other | 100 | (508) | 1,499 | (1,561) |
| Permanent differences and other | 472 | 238 | (394) | 290 |
| Total expense (benefit) for income taxes | $ 24,137 | $ (71,992) | $ 38,295 | $ 98,054 |
| Effective tax rate | 33.2% | 36.1% | 68.1% | 46.7% |

### Forward-Looking Statements

Certain sections of Management’s Discussion and Analysis of Financial Condition and Results of Operations include forward-looking statements concerning trends or events potentially affecting our business. These statements contain words such as “anticipates,” “believes,” “expects,” “targets,” “plans,” “projects,” “could,” “may,” “should,” “would” or similar words indicating that future outcomes are uncertain. In accordance with “safe harbor” provisions of the Private Securities Litigation Reform Act of 1995, these statements are accompanied by cautionary language identifying important factors, though not necessarily all such factors, which could cause future outcomes to differ materially from those set forth in the forward-looking statements. These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. While management believes that these forward-looking statements are reasonable when made, there can be no assurance that future developments affecting us will be those that we anticipate. All comments concerning our expectations for future revenues and operating results are based on our current forecasts for our existing operations and do not include the potential impact of any future events. 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. For additional risk factors affecting our business, see Item 1A. Risk Factors as set forth in our Annual Report on Form 10-K for the year ended December 31, 2017, as filed with the SEC on February 28, 2018.

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

#### *Cash Flow*

Cash flows from operations are primarily affected by production volumes and commodity prices, net of the effects of settlements of our derivatives. Our cash flows from operations are also impacted by changes in working capital. We generally maintain low cash and cash equivalent balances because we use available funds to reduce our bank debt. Short-term liquidity needs are satisfied by borrowings under our bank credit facility. Because of this, and 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. From time to time, we enter into various derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future natural gas, NGLs and oil production. The production we hedge has varied and will continue to vary from year to year depending on, among other things, our expectation of future commodity prices. Any payments due to counterparties under our derivative contracts should ultimately be funded by prices received from the sale of our production. Production receipts, however, often lag payments to the counterparties. As of September 30, 2018, we have entered into derivative agreements covering 148.1 Bcfe for the remainder of 2018, 356.2 Bcfe for 2019 and 7.0 Bcfe for 2020, not including our basis swaps.

The following table presents sources and uses of cash and cash equivalents for the nine months ended September 30, 2018 and 2017 (in thousands):

| | Nine Months Ended September 30, 2018 | Nine Months Ended September 30, 2017 |
|---|---|---|
| **Sources of cash and cash equivalents** | | |
| Operating activities | $ 774,947 | $ 600,532 |
| Disposal of assets | 24,339 | 27,583 |
| Borrowing on credit facility | 1,602,000 | 1,486,000 |
| Other | 45,824 | 38,825 |
| Total sources of cash and cash equivalents | $ 2,447,110 | $ 2,152,940 |
| **Uses of cash and cash equivalents** | | |
| Additions to natural gas and oil properties | $ (781,554) | $ (771,067) |
| Repayment on credit facility | (1,547,000) | (1,282,000) |
| Repayment of senior notes | — | (500) |
| Acreage purchases | (50,461) | (46,967) |
| Additions to field service assets | (1,230) | (4,687) |
| Dividends paid | (14,950) | (14,876) |
| Debt issuance costs | (8,257) | (247) |
| Other | (43,749) | (32,381) |
| Total uses of cash and cash equivalents | $ (2,447,201) | $ (2,152,725) |

**Net cash provided from operating activities** in first nine months 2018 was $774.9 million compared to $600.5 million in first nine months 2017. Cash provided from operating activities is largely dependent upon commodity prices and production volumes, net of the effects of settlement of our derivative contracts. The increase in cash provided from operating activities from 2017 to 2018 reflects a 14% increase in production and higher net realized prices (an increase of 6%) somewhat offset by higher operating costs. As of September 30, 2018, we have hedged more than 75% of our projected total production for the remainder of 2018, with more than 80% of our projected natural gas production hedged. Net cash provided from continuing operations is affected by working capital changes or the timing of cash receipts and disbursements. Changes in working capital (as reflected in our consolidated statements of cash flows) for first nine months 2018 were negative $20.3 million compared to negative $10.0 million for first nine months 2017.

**Disposal of assets** in first nine months 2018 includes $23.3 million of proceeds received from the sale of our Northern Oklahoma properties which closed in July 2018. In first nine months 2017, disposal of assets included $26.0 million of proceeds received from the sale of certain Western Oklahoma properties which closed in February 2017.

**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, access to the debt and equity capital markets and asset sales. We must find new reserves and develop existing reserves to maintain and grow our production and cash flows. We accomplish this primarily through successful drilling programs which require substantial capital expenditures. We continue to take steps to ensure we have adequate capital resources and liquidity to fund our capital expenditure program. In first nine months 2018, we entered into additional commodity derivative contracts for 2018, 2019, 2020 and 2021 to protect future cash flows. Effective April 13, 2018, we entered into an amended and restated revolving bank credit facility, which expires in April 2023, with terms that were similar to our previous bank credit facility.

During first nine months 2018, our net cash provided from operating activities of $774.9 million and borrowings under our bank credit facility were used to fund approximately $833.2 million of capital expenditures (including acreage acquisitions). At September 30, 2018, we had $357,000 in cash and total assets of $11.9 billion.

Long-term debt at September 30, 2018 totaled $4.2 billion, including $1.3 billion outstanding on our bank credit facility, $2.9 billion of senior notes and $49.0 million of senior subordinated notes. Our available committed borrowing capacity at September 30, 2018 was $452.6 million, with an additional $1.0 billion in borrowing base capacity available for increased liquidity potential. Cash is required to fund capital expenditures necessary to offset inherent declines in production and reserves that are typical in the oil and natural gas industry. Future success in growing reserves and production will be highly dependent on capital resources available and the success of finding or acquiring additional reserves. We currently believe that net cash generated from operating activities, unused committed borrowing capacity under the bank credit facility and proceeds from asset sales combined with our natural gas, NGLs and oil derivatives contracts currently in place will be adequate to satisfy near-term financial obligations and liquidity needs. While our expectation is to operate within our internally generated cash flow, to the extent our capital requirements exceed our internally generated cash flow and proceeds from asset sales, debt or equity securities may be issued to fund these requirements. Long-term cash flows are subject to a number of variables including the level of production and prices as well as various economic conditions that have historically affected the oil and natural gas business. A material decline in natural gas, NGLs and oil prices or a reduction in production and reserves would reduce our ability to fund capital expenditures, meet financial obligations and operate profitably. We establish a capital budget at the beginning of each calendar year and review it during the course of the year, taking into account various factors including the commodity price environment. Our 2018 capital budget is currently $941.2 million.

Commodity prices have remained volatile but have improved during 2018 compared to fourth quarter 2017. 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 plan to continue to work towards profitable growth within cash flows. We would expect to monitor the market and look for opportunities to refinance or reduce debt based on market conditions. We believe we are well-positioned to manage the challenges presented in a low commodity price environment and that we can endure continued volatility in current and future commodity prices by:

- exercising discipline in our capital program with the expectation of funding our capital expenditures with operating cash flow and, if required, with borrowings under our bank credit facility;
- continuing to optimize our drilling, completion and operational efficiencies; and
- continuing to manage price risk by hedging our production volumes.

***Credit Arrangements***

As of September 30, 2018, we maintained a revolving credit facility with a borrowing base of $3.0 billion and aggregate lender commitments of $2.0 billion, which we refer to as our bank credit facility. The bank credit facility, during a non-investment grade period, is secured by substantially all of our assets and has a maturity date of April 13, 2023. See Note 9 to our unaudited consolidated financial statements for additional information regarding our bank debt. Availability under the bank credit facility is subject to a borrowing base set by the lenders annually with an option to set more often in certain circumstances. Availability under the bank credit facility, during an investment grade period, is limited to aggregate lender commitments. As of September 30, 2018, the outstanding balance under our credit facility was $1.3 billion. Additionally, we had $281.4 million of undrawn letters of credit leaving $452.6 million of committed borrowing capacity available under the facility at the end of third quarter 2018, with an additional $1.0 billion in borrowing base capacity for potential increases in lender commitments.

Our bank credit facility imposes limitations on the payment of dividends and other restricted payments (as defined under our bank credit facility). The bank credit facility also contains customary covenants relating to debt incurrence, liens, investments and financial ratios. We were in compliance with all covenants at September 30, 2018. See Note 9 to our unaudited consolidated financial statements for additional information regarding our bank debt.

***Cash Dividend Payments***

On August 31, 2018, our Board of Directors declared a dividend of two cents per share ($5.0 million) on our outstanding common stock, which was paid on September 28, 2018 to stockholders of record at the close of business on September 14, 2018. The amount of future dividends is subject to discretionary declaration by the Board of Directors and primarily depends on earnings, capital expenditures, debt covenants and various other factors.

***Cash Contractual Obligations***

Our contractual obligations include long-term debt, operating leases, derivative obligations, asset retirement obligations and transportation, processing and gathering commitments. As of September 30, 2018, we do not have any capital leases. As of September 30, 2018, we do not have any significant off-balance sheet debt or other such unrecorded obligations and we have not guaranteed any debt of any unrelated party. As of September 30, 2018, we had a total of $281.4 million of undrawn letters of credit under our bank credit facility.

Since December 31, 2017, there have been no material changes to our contractual obligations other than a $55.0 million increase in our outstanding bank credit facility balance, a new pipeline brought into service in Pennsylvania and pricing changes for current contracts. Our contractual obligations for firm transportation and gathering contracts increased by approximately $2.4 billion over the next twenty years related to these changes.

**Interest Rates**

At September 30, 2018, we had approximately $4.2 billion of debt outstanding. Of this amount, $2.9 billion bore interest at fixed rates averaging 5.2%. Bank debt totaling $1.3 billion bears interest at floating rates, which was 3.9% at September 30, 2018. The 30-day LIBOR Rate on September 30, 2018 was approximately 2.3%. A 1% increase in short-term interest rates on the floating-rate debt outstanding on September 30, 2018 would cost us approximately $12.7 million in additional annual interest expense.

### Off-Balance Sheet Arrangements

We do not currently utilize any significant off-balance sheet arrangements with unconsolidated entities to enhance our liquidity or capital resource position, or for any other purpose. However, as is customary in the oil and gas industry, we have various contractual work commitments, some of 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 for the remainder of 2018 to continue to be a function of supply.

### Certain New Accounting Standards Not Yet Adopted

The effects of certain new accounting standards that have not been adopted yet are discussed in Note 3 to the consolidated financial statements.

## ITEM 3. 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. Changes in natural gas prices affect us more than changes in oil prices because approximately 67% of our December 31, 2017 proved reserves are natural gas. We are also exposed to market risks related to changes in interest rates. These risks did not change materially from December 31, 2017 to September 30, 2018.

**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 can also include collars, which establish a minimum floor price and a predetermined ceiling price. We have also entered into natural gas derivative instruments containing a fixed price swap and a sold option (referred to as a swaption in the table below). At September 30, 2018, our derivative program includes swaps, calls, collars and swaptions. The fair value of these contracts, represented by the estimated amount that would be realized upon immediate liquidation as of September 30, 2018, approximated a net unrealized pretax loss of $104.8 million. These contracts expire monthly through December 2020. At September 30, 2018, 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 |
|---|---|---|---|---|
| **Natural Gas** | | | | (in thousands) |
| 2018 | Swaps | 1,193,370 Mmbtu/day | $ 2.96 | $ (8,430) |
| 2019 | Swaps | 594,589 Mmbtu/day | $ 2.82 | $ 4,902 |
| 2018 | Calls | 70,000 Mmbtu/day | $ 3.10 (1) | $ (504) |
| 2018 | Swaptions | 160,000 Mmbtu/day | $ 3.07 (2) | $ (4,900) |
| 2019 | Swaptions | 298,014 Mmbtu/day | $ 2.86 (2) | $ 8,681 |
| 2020 | Swaptions | 10,000 Mmbtu/day | $ 2.75 (2) | $ 353 |
| **Crude Oil** | | | | |
| 2018 | Swaps | 8,500 bbls/day | $ 53.20 | $ (15,163) |
| 2019 | Swaps | 7,000 bbls/day | $ 55.26 | $ (39,055) |
| 2020 | Swaps | 1,500 bbls/day | $ 60.63 | $ (3,205) |
| 2019 | Collars | 1,000 bbls/day | $ 63.00 − $ 73.03 | $ (717) |
| **NGLs (C3-Propane)** | | | | |
| 2018 | Swaps | 11,668 bbls/day | $ 0.74/gallon | $ (16,767) |
| January – June 2019 | Swaps | 7,500 bbls/day | $ 0.92/gallon | $ (3,593) |
| 2018 | Collars | 5,000 bbls/day | $ 0.95 − $ 1.04 | $ (1,499) |
| January – March 2019 | Collars | 6,500 bbls/day | $ 0.92 − $ 1.02 | $ (1,738) |
| **NGLs (NC4-Normal Butane)** | | | | |
| 2018 | Swaps | 5,500 bbls/day | $ 0.91/gallon | $ (8,145) |
| January – March 2019 | Swaps | 2,250 bbls/day | $ 1.22/gallon | $ (78) |
| **NGLs (C5-Natural Gasoline)** | | | | |
| 2018 | Swaps | 5,402 bbls/day | $ 1.24/gallon | $ (8,290) |
| 2019 | Swaps | 2,178 bbls/day | $ 1.42/gallon | $ (6,647) |

(1) Weighted average deferred premium of $0.16.

(2) Contains a combined derivative instrument consisting of a fixed price swap and a sold option to extend or double the volume. For October through December of 2018 we 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. We have swaps in place for 2019 for 185,000 Mmbtu/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 2019 for 150,000 Mmbtu per day on which the counterparty can elect to extend the contract through December 2020 at a weighted average price of $2.81. For 2020, we have swaps in place for 10,000 Mmbtu/day on which the counterparty can elect to double the volume at a weighted average price of $2.75.

In the future, we expect our NGLs production to continue to increase. We believe NGLs prices are somewhat seasonal, particularly for propane. Therefore, the relationship 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 arrangements at Sunoco’s Marcus Hook Industrial Complex facility near Philadelphia began ethane operations in early 2016. We cannot assure you that these facilities will remain available. If we are not able to sell ethane under at least one of these agreements, we may be required to curtail production or, as we have done in the past, purchase or divert natural gas to blend with our rich residue gas.

**Other Commodity Risk**

We are impacted by basis risk, caused by factors that affect the relationship between commodity futures prices reflected in derivative commodity instruments and the cash market price of the underlying commodity. 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. Therefore, in addition to the swaps discussed above, we have entered into natural gas basis swap agreements. The price we receive for our gas production can be more or less than the NYMEX Henry Hub price because of basis adjustments, relative quality and other factors. Basis swap agreements effectively fix the basis adjustments. The fair value of the natural gas basis swaps was a loss of $1.3 million at September 30, 2018 and they settle monthly through September 2021.

At September 30, 2018, we also had propane basis contracts which lock in the differential between Mont Belvieu and international propane indices. The contracts settle monthly through December 2019 and include a total volume of 1,943,000 barrels. The fair value of these contracts was a loss of $2.0 million on September 30, 2018.

The following table shows the fair value of our swaps and basis swaps and the hypothetical changes in fair value that would result from a 10% and a 25% change in commodity prices at September 30, 2018. 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 Increase of | | Hypothetical Change in Fair Value Decrease of | |
|---|---|---|---|---|---|
| | Fair Value | 10% | 25% | 10% | 25% |
| Swaps | $ (104,471) | $ (140,424) | $ (351,057) | $ 141,359 | $ 355,408 |
| Collars | (3,954) | (6,094) | (15,689) | 5,784 | 14,633 |
| Swaptions | 4,134 | (53,839) | (167,254) | 40,971 | 93,879 |
| Calls | (504) | (1,241) | (3,954) | 366 | 487 |
| Basis swaps | (3,296) | (55) | (58) | 26 | 75 |
| Freight swaps | 301 | 303 | 758 | (303) | (766) |

Our commodity-based derivative contracts expose us to the credit risk of non-performance by the counterparty to the contracts. Our exposure is diversified primarily among major investment grade financial institutions and we have master netting agreements with 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 September 30, 2018, our derivative counterparties include twenty-one 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 our counterparties are primarily major investment grade financial institutions, the fair value of our derivative contracts has 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. Our 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 senior and senior subordinated debt and variable rate bank debt. At September 30, 2018, we had $4.2 billion of debt outstanding. Of this amount, $2.9 billion bears interest at fixed rates averaging 5.2%. Bank debt totaling $1.3 billion bears interest at floating rates, which was 3.9% on September 30, 2018. On September 30, 2018, the 30-day LIBOR Rate was approximately 2.3%. A 1% increase in short-term interest rates on the floating-rate debt outstanding on September 30, 2018, would cost us approximately $12.7 million in additional annual interest expense.

## ITEM 4. CONTROLS AND PROCEDURES

**Evaluation of Disclosure Controls and Procedures**

As required by Rule 13a-15(b) of the Securities Exchange Act of 1934, as amended (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 Quarterly Report on Form 10-Q. Our disclosure controls and procedures are designed to provide reasonable assurance that the 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 have concluded that our disclosure controls and procedures were effective as of September 30, 2018 at the reasonable assurance level.

**Changes in Internal Control over Financial Reporting**

There was no change in our system of internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the quarter ended September 30, 2018 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

# PART II – OTHER INFORMATION

## ITEM 1. LEGAL PROCEEDINGS

See Note 16 to our unaudited consolidated financial statements entitled “Commitments and Contingencies” included in Part I Item 1 above for a summary of our legal proceedings, such information being incorporated herein by reference.

**Environmental Proceedings**

Our subsidiary, Range Resources – Appalachia, LLC, was notified by the Pennsylvania Department of Environmental Protection (“DEP”), in second quarter 2015, 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 1A. RISK FACTORS

We are subject to various risks and uncertainties in the course of our business. In addition to the factors discussed elsewhere in this report, you should carefully consider the risks and uncertainties described under Item 1A. Risk Factors filed in our Annual Report on Form 10-K for the year ended December 31, 2017. There have been no material changes from the risk factors previously disclosed in that Form 10-K.

## ITEM 6. EXHIBITS

**Exhibit index**

| Exhibit Number | Exhibit Description |
|---|---|
| 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 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 Resources Corporation (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) |
| 10.1 | Sixth Amended and Restated Credit Agreement, dated April 13, 2018 among Range (as borrower) and JPMorgan Chase Bank, N.A. 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 8-K (File No. 001-12209) as filed with the SEC on April 16, 2018) |
| 10.2 | Voting Support and Nomination Agreement, dated as of July 9, 2018, by and among Range Resources Corporation, SailingStone Capital Partners LLC and SailingStone Holdings LLC (incorporated by reference to Exhibit 10.1 to Form 8-K (File No. 001-12209) as filed with the SEC on July 10, 2018) |
| 31.1* | Certification by the President and Chief Executive Officer of Range Resources Corporation Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 |
| 31.2* | Certification by the Chief Financial Officer of Range Resources Corporation Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 |
| 32.1** | Certification by the President and Chief Executive Officer of Range Resources Corporation 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 Resources Corporation Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| 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 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.

Date: October 23, 2018

RANGE RESOURCES CORPORATION

By: /s/ MARK S. SCUCCHI

**Mark S. Scucchi**
***Senior Vice President and***
***Chief Financial Officer***

Date: October 23, 2018

RANGE RESOURCES CORPORATION

By: /s/ DORI A. GINN

**Dori A. Ginn**
***Senior Vice President – Controller and***
***Principal Accounting Officer***

**Exhibit 31.1**

# CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Jeff L. Ventura, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Range Resources Corporation (the "registrant");
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 23, 2018

/s/ JEFF L. VENTURA

**Jeff L. Ventura**

***President and Chief Executive Officer***

**Exhibit 31.2**

**CERTIFICATION OF CHIEF FINANCIAL OFFICER**

I, Mark S. Scucchi, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Range Resources Corporation (the “registrant”);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: October 23, 2018

/s/ Mark S. Scucchi

**Mark S. Scucchi**
***Senior Vice President and Chief Financial Officer***

**Exhibit 32.1**

**CERTIFICATION OF
PRESIDENT AND CHIEF EXECUTIVE OFFICER
OF RANGE RESOURCES CORPORATION
PURSUANT TO 18 U.S.C. SECTION 1350 AS ADOPTED
PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report on Form 10-Q for the period ending September 30, 2018 and filed with the Securities and Exchange Commission on the date hereof (the "Report") and pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, I, Jeff L. Ventura, President and Chief Executive Officer of Range Resources Corporation (the "Company"), hereby certify that, to my knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

By: /s/ JEFF L. VENTURA
**Jeff L. Ventura**

October 23, 2018

**Exhibit 32.2**

**CERTIFICATION OF
CHIEF FINANCIAL OFFICER
OF RANGE RESOURCES CORPORATION
PURSUANT TO 18 U.S.C. SECTION 1350 AS ADOPTED
PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report on Form 10-Q for the period ending September 30, 2018 and filed with the Securities and Exchange Commission on the date hereof (the “Report”) and pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, I, Mark S. Scucchi, Chief Financial Officer of Range Resources Corporation (the “Company”), hereby certify that, to my knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

By: /s/ MARK S. SCUCCHI
**Mark S. Scucchi**

October 23, 2018